evaluating Long Island's needs relative to its on-Island ICAP Requirements and the 50% confidence level for evaluating Long Island's needs relative to its Statewide ICAP and OPCAP Requirements.

Ultimately the more stringent of the planning requirements will be used for planning the resource needs for Long Island. In this analysis the results indicate the Long Island on-Island ICAP criteria to be the more stringent and as such becomes the driver of the resource plan and the following conclusions.

7.4.1 Resource Adequacy Conclusions

Based on the results of its resource adequacy and uncertainty analyses, certain conclusions can be drawn regarding the need for additional resources during the study period. These are listed as follows:

1. **The NYISO Long Island on-Island need is the driving criteria for this resource plan.** LIPA has a need to obtain a significant portion of its required resources from on-Island resources.
2. **ELI significantly reduces the need for additional resources on Long Island.** The initial year of need is deferred for two years from 2014 to 2016 and the overall need for additional resources is reduced by nearly 900 MW by the year 2028.
3. **LIPA has a growing need to procure capacity on a statewide basis**. Under both reference need case and probabilistic assessment case assumptions, LIPA's total resource position grows increasingly deficient for the entire study period.

Based these results, LIPA has undertaken a resource type assessment to develop the power supply strategy to meet its forecast resource adequacy needs. That analysis is described in Sections 8 and 9 of this appendix.

8 Alternative Technology Assessment

This section presents a screening analysis of over 80 alternative technologies in order to narrow down the selection of technologies that are used in the development of alternative plans. The technology options evaluated include alternatives that are available today, as well as those anticipated to be available during the plan period. The technologies of interest and the approach taken to assess them are discussed in this section.

8.1 Alternative Technologies Considered

The alternative technologies shown in Exhibit 8-1 were screened during the development of the Electric Resource Plan. Options considered included peak load reduction programs, energy efficiency programs, generation options, retirement options at specified power sites, renewable resource options, repowering options at existing facilities, and transmission options both on and off Long Island. In addition to the specific options listed, multiple types of some options were evaluated (e.g. a 501 G combined cycle unit and a 7FA combined cycle unit) and combinations of technologies (such as an off-Island combined cycle unit combined with a second PJM cable).

Exhibit 8-1 Alternative Technologies Considered

Supply Options	**Transmission Options**
Generic On-Island Combined–Cycle	Loss Reduction
Generic On-Island CT LMS 100 CC	NUSCO Upgrade 1
Caithness Combined-Cycle	NUSCO Upgrade 2
Generic Off-Island Combined–Cycle	Neptune Cable (RB)
Combined-Cycle CT LM6000	Neptune Cable (UDR)
Simple-Cycle CT LM6000	PJM Cable II (RB)
Generic Off-Island Coal	PJM Cable II (UDR)
Mobile Generating Units	Neptune Cable w/Marcus Hook
Fuel Cell Stack	Cross-Sound Cable
Pratt & Whitney (Twin Pac)	Hydro Quebec Inter-tie Reinforcements
Generic Off-Island Nuclear	
Efficiency Options	**Renewable Options**
Clean Energy Initiative	Landfill Waste-to-Energy**
ELI Base Program	Barrett 1,2, Convert to B20 Diesel
ELI Advanced & Accelerated Program	East Hampton, Convert to B20 Diesel
Intelligent Metering	Resource Recovery
Time-based Pricing	Shoreham, Convert to Biodiesel
	On-Island CT Bio-Diesel

	Photovoltaic Roof
	On-Shore Wind
	Off-Shore Wind
	Off-Island Renewables
	Solar Pioneer
Repowering Options	**Retirement Options**
Barrett Repowering	Barrett Retirement
Northport Repowering	Northport Retirement
Port Jefferson Repowering	Port Jefferson Retirement
Shoreham Repowering	Shoreham Retirement
Wading River Repowering	Far Rockaway Retirement
	Glenwood Retirement
	Wading River Retirement
	Peaking CTs and Diesels

**Landfill Waste to Energy is not currently considered a renewable resource by the New York State RPS regulatory framework.

8.2 Technology Evaluation Metrics

A major part of reviewing alternative technologies is the development of the assumptions and the collecting of the the quantitative and qualitative data needed to sift among alternatives. Once the data is gathered, an extensive list of reasonable alternative resources and technologies is assembled for review and evaluation. The alternative technologies are compared on the basis of economic and environmental metrics.

The screening analysis was prepared using fuel price projections developed in the December 2008 to January 2009 time-frame. The cost of technologies was based on information originally developed in September 2008 and updated in December 2008.

Technologies within each group are evaluated and ranked on a levelized cost basis, expressed in energy ($/MWh) and capacity cost ($/kW-month). Levelized cost is a unitized cost calculated by discounting both an annual stream of costs, or "then year" dollars, which includes the effect of inflation & escalation, and an annual stream of output, or "then year" output in MWh, using a discount rate representative of LIPA's cost of debt, including inflation. Levelized total costs include fixed, production, and emission allowance costs.

The lower total cost technologies within each group are summarized by type of resource. A preferred list of selected technologies is then developed from the resources with the lowest cost and other preferred characteristics.

8.3 Screening Analysis Approach

In order to assess the relative benefits of alternative technologies LIPA uses the levelized cost approach mentioned above to evaluate technology options. This approach offers the advantages of a quick turnaround time once assumptions have been developed, a high level relative comparisons of the life cycle costs of alternative technologies and an easy analysis of sensitivity to input assumptions. This method does have some disadvantages in that it is a simplified analysis, it offers no information on implications of the dispatch of various generating units, and certain assumptions such as an assumed unit capacity factor replace detailed production simulation analysis. The performance of the technology within a power system and the impact on the operation of the rest of the system are not considered.

LIPA has devoted significant effort and attention to developing and performing this screening analysis. Exhibit 8-1 provides an extensive list of the alternative resource technologies that were assembled for evaluation. A short list of preferred technologies was selected from this list for further detailed evaluation and inclusion in the development of Alternative Resource Plans discussed in Section 9 of this appendix.

8.3.1 Analysis Phases and Groups

In order to facilitate analysis, the list of alternative technologies is broken down into five "phases" and sixteen "groups". The groupings represent similar technologies (e.g. 7FA, 501G, LMS100 LM6000 CC generator technologies) in order to facilitate like for like comparisons. The groups in turn are combined into phases that represent categories of alternatives specifically their physical location, their reproducibility and whether they are new or existing resources.

Reproducibility is delineated between "replicable" resources and "limited" resources. Replicable resources, as used herein, refer to the ability to easily replicate the resource in another location or at another point in time. For example, a series of 501G combined cycle units could be installed at various locations on Long Island over time, and the operating characteristics of each would remain very similar. Limited resources, on the other hand, are described herein as somewhat constrained resources, without the ability to expand these resources indefinitely. For example, landfill gas fired generating units are limited by the number of suitable landfill sites on Long Island. Similarly, to a lesser degree, energy efficiency, solar, and wind resources may be somewhat constrained by physical limits if the resources were to be solely relied upon to meet future load growth. Once the Efficiency Long Island program is implemented, while further energy efficiency is possible, the ELI program cannot be duplicated several times over in an identical manner.

The phase categories are:

- Phase 1 – New replicable resource located on Long Island (e.g., 7FA generator, 501G generator)
- Phase 2 - New replicable resource located off Long Island (e.g., Upstate New York Combined Cycle)
- Phase 3 – New limited resource located on Long Island (e.g., Efficiency Long Island ("ELI"), Automated Meter Initiative ("AMI"))
- Phase 4 – Existing resource located on Long Island (e.g., Neptune Cable, Northport)
- Phase 5 – Repowered resource located on Long Island (e.g., Barrett Repower)

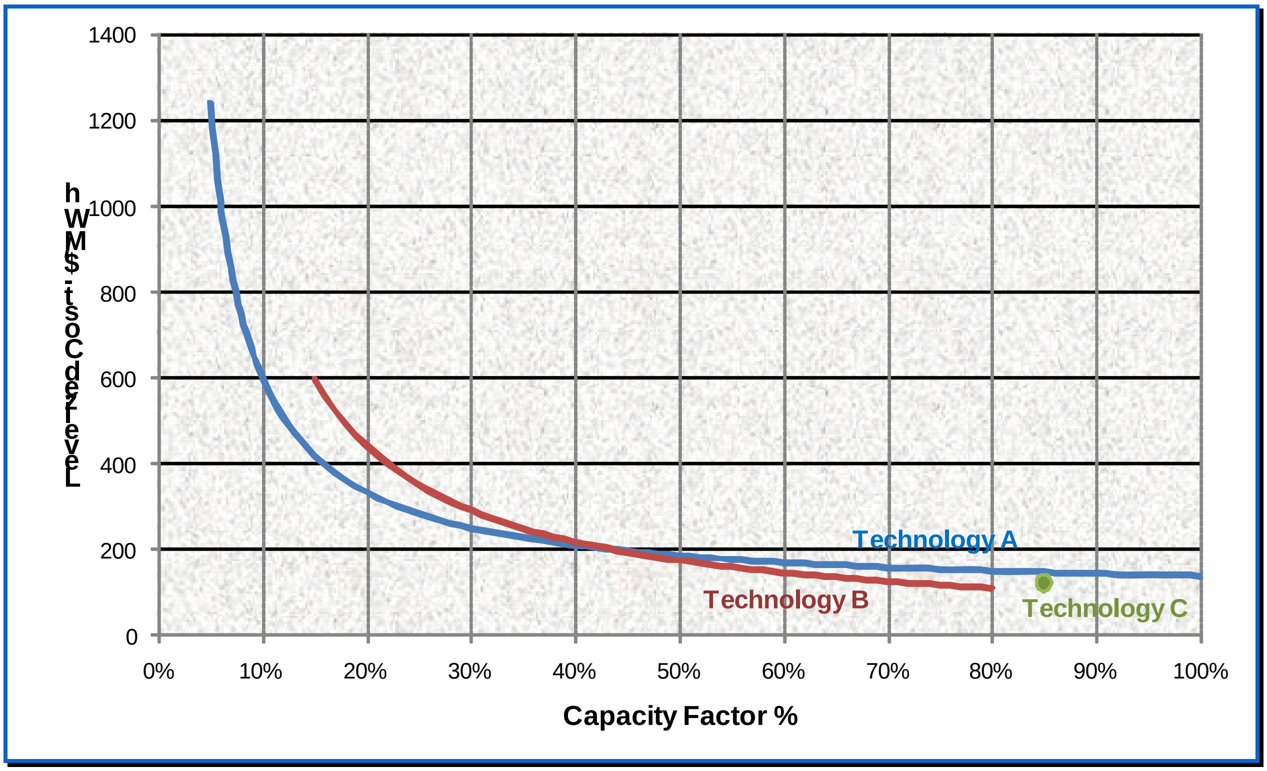
8.3.2 Sample Analysis

The analysis for each group contains a graph, a table, and a discussion. A sample graph containing hypothetical technologies is shown in Exhibit 8-2. Many technologies are dispatchable; in that the amount of energy produced can be varied depending upon how much energy is required. Since each technology has a different mix of fixed and variable costs, the levelized cost per kWh varies differently for each technology. This graph shows how each technology performs in terms of the total dollars per megawatt-hour of energy produced. In our example graph:

- Technology A is a dispatchable resource with has low variable costs and high fixed costs (e.g., combined cycle)
- Technology B has high variable costs and low fixed costs (e.g., peaker); and
- Technology C is a non-dispatchable resource that produces a fixed amount of energy (e.g., fuel cell).

When compared on the example graph below, Technology A performs best when it its run at a high capacity factor (percentage of maximum possible output) and Technology B performs best at lower capacity factors. In addition, at its fixed capacity factor, Technology C is less expensive than Technology A and more expensive than Technology B. If these hypothetical examples were the only options available, the best plan would consist of a mix of technology A for intermediate and peaking purposes and technology B for base load purposes. Technology C would not be pursued unless it had other unique features such as low emissions or other attributes that made it attractive for policy reasons.

Exhibit 8-2 Sample Graph



A sample table is shown in Exhibit 8-3. This table shows the following information:

- ICAP MW – is the installed capacity value of the technology in megawatts. The greater the installed capacity the greater the potential to generate energy.
- Name – a descriptive title for a technology.
- Levelized Cost - Technologies within each group are evaluated and ranked on a levelized cost basis, expressed in energy ($/MWh) and capacity cost ($/kW-month) Levelized cost is a unitized cost calculated by discounting both an annual stream of costs ("then year" dollars, that include the

effect of inflation & escalation) and an annual stream of output ("then year" output in MWh) using a discount rate representative of LIPA's cost of debt, including inflation. Levelized total costs include fixed, production, and emission allowance costs. The lower total cost technologies within each group are summarized by type of resource. A "short-list" of selected technologies is then developed from the resources with the lowest cost and other preferred characteristics.

 - Capacity $/kW-mo – reflects the fixed costs (e.g., capital, fixed O&M, PILOTS) associated with a technology. Typically, higher capital costs are indicative of larger generating facilities which are called on in many hours, resulting in higher capacity factors.
 - Energy $/MWh – reflects the variable costs (e.g., fuel, emissions allowances, variable O&M) associated with a technology. Higher energy costs typically reflect peaking units which are called on to run only on a limited basis, resulting in lower capacity factors.
 - Total $/MWh – reflects the overall cost (fixed and variable) of operating a technology over a range of capacity factors.

- Environmental Emissions – reflects the emission rate associated with a technology. The levelized cost previously mentioned includes the actual cost of emission allowances based on varying levels of output.
 - CO_2 lb/MWh – pounds of CO_2 emitted for every megawatt-hour generated
 - NOx lb/MWh - pounds of NOx emitted for every megawatt-hour generated
 - SO_2 lb/MWh - pounds of SO_2 emitted for every megawatt-hour generated

Exhibit 8-3 Sample Table

ICAP MW	Name	Levelized Cost				Environmental Emissions		
		Capacity $/kW-mo	Energy $/MWh	Capacity Factor	Total $/MWh	CO_2 lb/MWh	NOx lb/MWh	SO_2 lb/MWh
100	Technology A	$34.54	$127.74	14%	$456.11	1137	0.0904	0.0066
250	Technology B	$21.37	$ 0	35%	$115.89	0	0.0000	0.0000
10	Technology C	$37.32	$97.51	78%	$163.18	862	0.0834	0.0051

Following each of these exhibits, which contain both a graph and a table, is a discussion of the results of the analysis of that particular grouping of technologies. The discussion describes the technologies, compares and contrasts their respective results, and then states conclusions and/or observations about those results.

8.4 Phase 1 – New Replicable Resource On-Island

The Phase 1 series of exhibits analyzes technologies which include new replicable technologies potentially to be located off Long Island.

- Group A: Reference 2x1 7FA, Reference 1x1 501G, Reference 1x1 7FA, Reference LMS100, LM6000 CC
- Group B: Pratt & Whitney SC, LM6000 SC, Emergency Diesels

8.4.1 Group A

Exhibit 8-4, Group A compares the levelized costs of conventional gas fired technologies. Many of the supply options in the LIPA Electric Resource Plan utilize either gas turbine or combined cycle technologies.

Gas turbines in the power industry require smaller capital investment than combined cycle or coal plants and can be designed to generate small or large amounts of power. Also, the actual construction process can take as little as several weeks to a few months, compared to years for base load plants. Their other main advantage is the ability to be turned on and off within minutes, supplying power during peak demand. The simple cycle gas turbines are modeled as a single unit or in a two unit configuration and range in size from 45 MW to 105 MW (2 units. These gas turbines can be configured to run in either simple cycle or combined cycle mode which significantly increases their efficiency. For purposes of this group, a distinction is made between the smaller gas turbines that can run in combined cycle mode and the large combined cycle power plants that are designed for base load. There are two General Electric gas turbine configurations utilized in the LIPA Draft Electric Resource Plan, a single unit with a steam turbine (GE LM6000) and a larger gas turbine in simple cycle mode (GE LMS100).Combined cycle power plants (also referred to as combined cycle gas turbine plants) is an integration of two types of prime movers, the gas turbine and the steam turbine, combining many of the advantages of both. The combined cycle recovers heat from the gas turbine's exhaust, uses the heat to generate steam in a heat recovery steam generator, then the steam is used to generate electricity. A combined cycle can provide large amounts of power on short notice with its quick start-up time and, with a higher fixed cost than gas turbines, the cost and time involved for construction remain below other similar sized coal or steam units. Additional combined-cycle advantages include reductions in NOx emissions, lower heat rates, and improved unit operability.

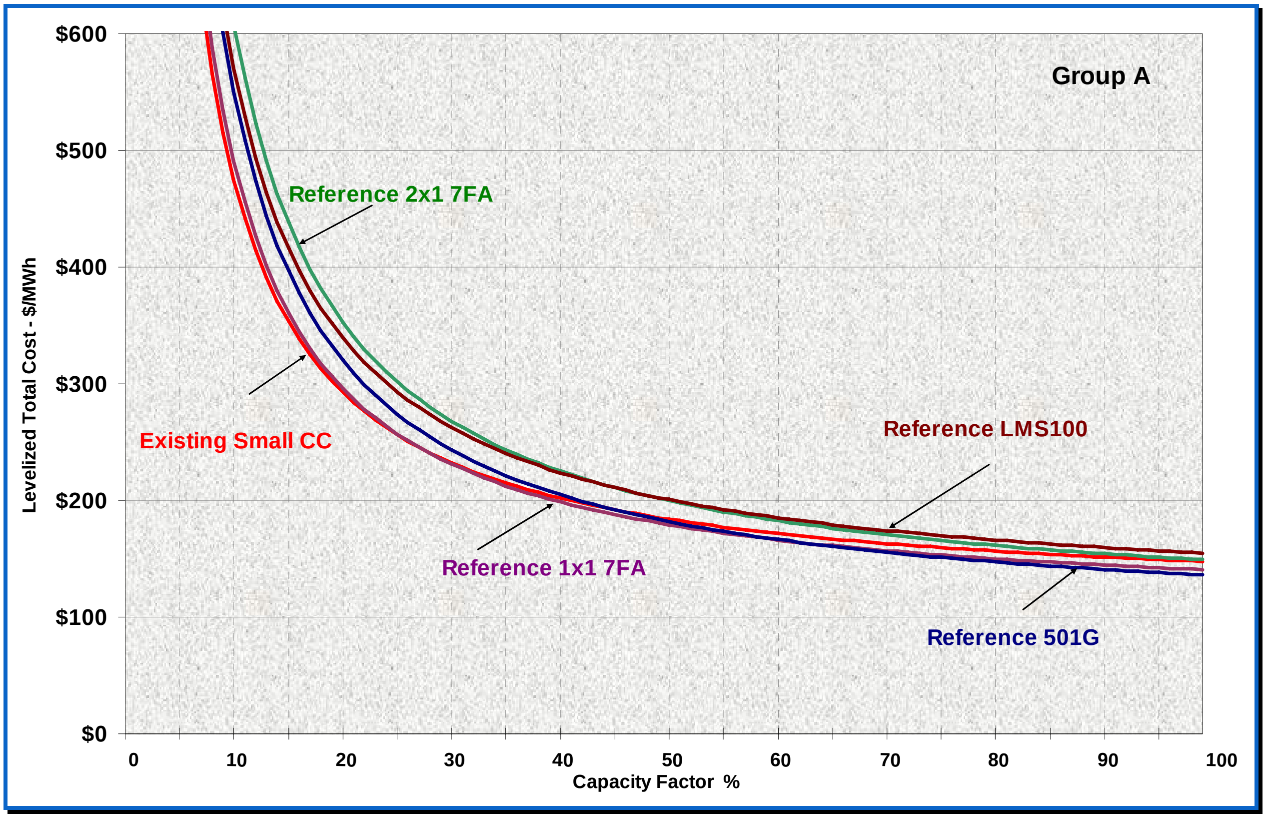
There are three combined cycle configurations utilized in the LIPA Draft Electric Resource Plan. Units from General Electric include a single unit (1x1 GE 7FA) at 250 MW, and a two unit configuration (2x1 GE 7FA) at 538 MW. Additionally a new 501G Siemens gas turbine is modeled in a 1x1 configuration with a power output of 378 MW. The 501G is a newer, less mature gas turbine design that is capable of attaining higher efficiencies. These higher efficiencies are achieved through a higher gas turbine exhaust temperature as well as through closed-loop steam cooling. The higher temperatures and increased cycle complexities may result in lower reliability and availability as compared to an "F" class machine, but the increased efficiencies should compensate for these factors.

The Group A supply side resource options included in the Electric Resource Plan are:

1. Existing Small CC (LM6000 Gas Turbine with Steam Turbine)
2. Reference LMS100 Gas Turbines
3. Reference 1x1 7FA Combined Cycle Power Plant
4. Reference 501G Combined Cycle Power Plant
5. Reference 2x1 7FA Combined Cycle Power Plant

The operating characteristics and costs for the above have been developed using a state of the art power plant software model. These units will be utilized in the modeling of new generation sites and in options that include repowering or replacing existing on-Island generation.

Exhibit 8-4 New Replicable Resource Located On Long Island – Group A



ICAP MW	Name	Levelized Cost				Environmental Emissions		
		Capacity $/kW-mo	Energy $/MWh	Capacity Factor	Total $/MWh	CO2 lb/MWh	NOx lb/MWh	SO2 lb/MWh
75	Existing Small CC	$26.55	$111.09	79%	$157.10	973	0.0887	0.0048
105	Reference LMS100	$33.75	$108.19	42%	$218.22	1125	0.8700	0.0068
240	Reference 1x1 7FA	$28.46	$101.20	75%	$153.30	875	0.0825	0.0053
367	Reference 501G	$33.63	$89.73	82%	$145.76	828	0.0575	0.0042
480	Reference 2x1 7FA	$37.32	$97.51	78%	$163.18	862	0.0834	0.0051

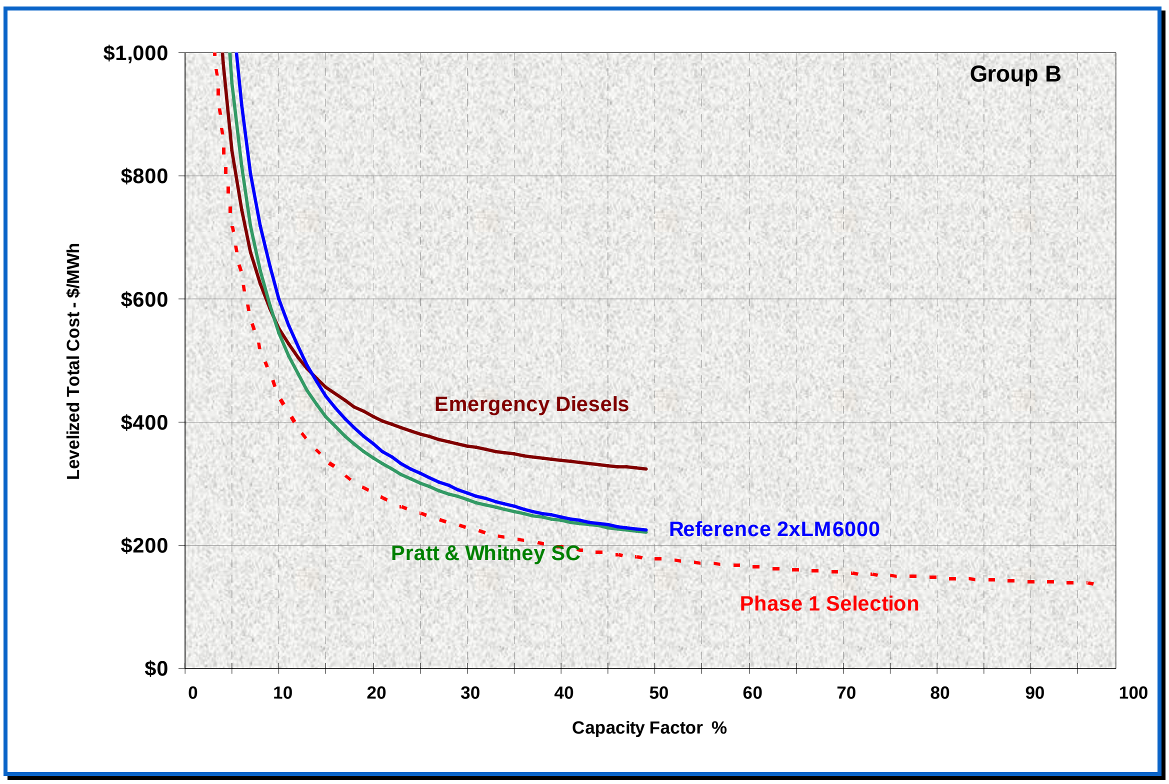
Analysis of the Group A results in Exhibit 8-4 reveals a relatively small but significant economic advantage to the GE 7FA and the Siemens 501G technologies dependant on their range of operation. The 7FA is the more cost effective than the 501G operating at capacity factors below 50% due to its lower fixed costs. Above 50% capacity factor, the range in which these technologies typically operate, the higher efficiencies of the 501G machine make it the lower cost choice. In terms of their likely dispatch within the Long Island market the table at the bottom of the exhibit confirms the technology preferences stated previously with the 501G as the lowest cost followed by the 7FA. From an environmental emissions standpoint the picture is much the same with the 501G having a consistently lower emissions profile followed by the 7FA. Existing small CCs are attractive options at capacity factors below 20% due to their relatively small scale and lower capital costs.

8.4.2 Group B

Exhibit 8-5, Group B, compares the levelized costs for replicable conventional gas fired peaking technologies to be located potentially on Long Island. These technologies included Emergency Diesels, LM6000's and the Pratt & Whitney simple cycle combustion turbine technology.

The cost comparison shows a small but clear economic advantage to the Pratt & Whitney simple cycle combustion turbine technology for capacity ranges below 50% within this group. The dotted line shows the cost of the Phase 1 Selection technology, a combination of the lowest cost technologies of Group A. However, this advantage is eliminated if the comparison group is expanded to include Group A technologies, specifically the 7FA. The 7FA is the economic choice at capacity factors below 50%. At capacity factors below 5% peaking technologies such as the Emergency Diesels and the Pratt & Whiney technologies become attractive alternatives. Intermediate to base load technologies such as combined cycle units are not attractive options at these very low capacity factors due to their comparatively high capital costs.

Exhibit 8-5 New Replicable Resource Located On Long Island – Group B



ICAP MW	Name	Levelized Cost				Environmental Emissions		
		Capacity $/kW-mo	Energy $/MWh	Capacity Factor	Total $/MWh	CO2 lb/MWh	NOx lb/MWh	SO2 lb/MWh
44	Emergency Diesels	$20.97	$265.82	1%	$3,137.28	0	0.0000	0.0000
55	Pratt & Whitney SC	$29.64	$138.98	8%	$619.37	1669	3.0297	0.0154
80	Reference 2xLM6000 SC	$34.54	$127.74	14%	$456.11	1137	0.0904	0.0066

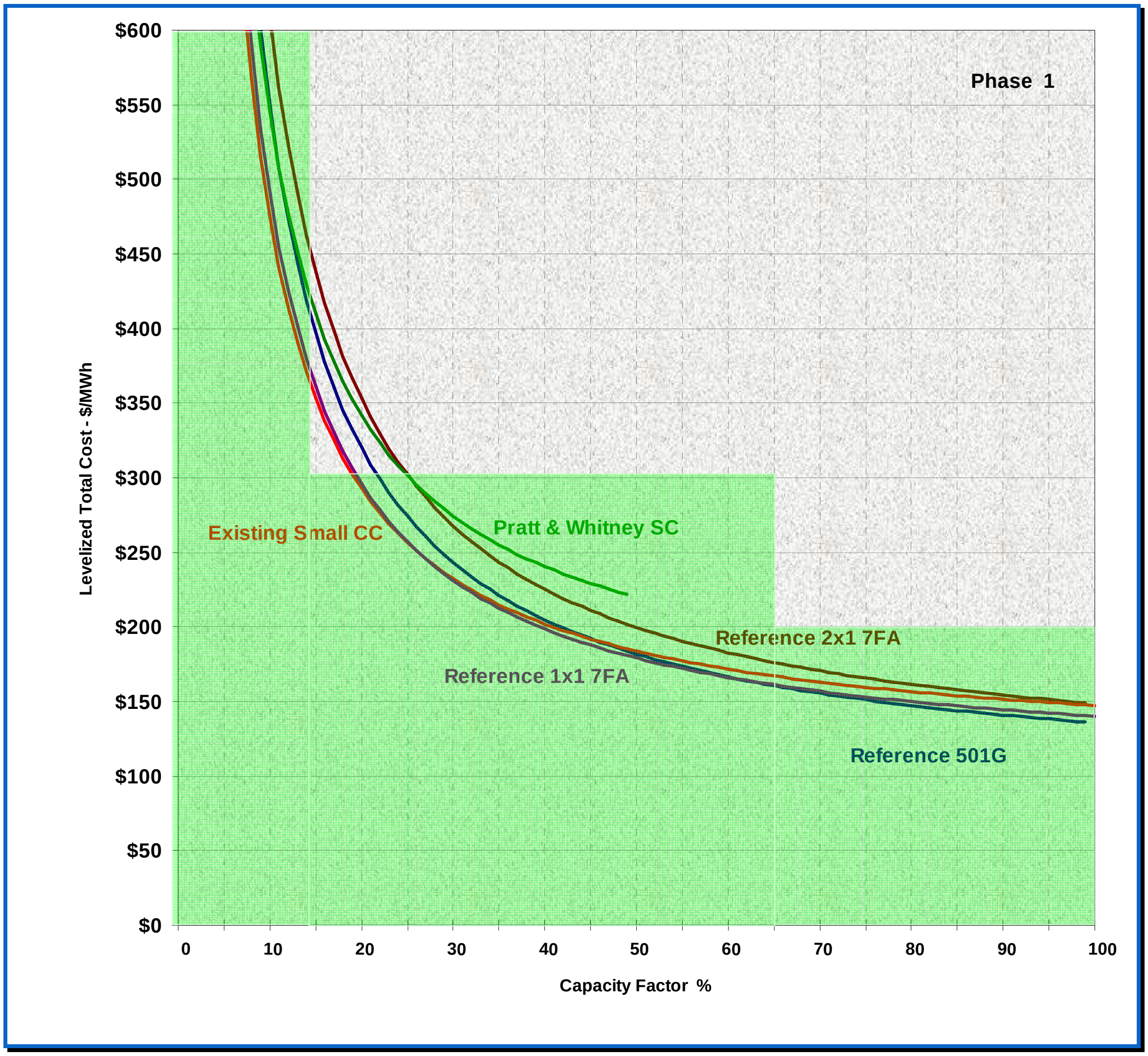
At the predicted dispatch level for the Long Island market, the LM6000 SC is lower cost technology in Group B on a levelized total dollar per megawatt-hour basis. The LM6000 is somewhat higher in capital cost but it is also more efficient than the Pratt & Whitney. This higher level of production efficiency has the effect of increasing the predicted level of dispatch which in turn results in a lower overall cost on a total dollar per megawatt-hour basis.

Environmentally the Pratt & Whitney produces significantly higher levels of NOx emissions in comparison to the other technologies in both A and B Groups which is a significant disadvantage.

8.4.3 Phase 1 Summary

Exhibit 8-6 combines the results of the Group A & B levelized cost comparison. Taken in combination the top performers in Groups A and B, the 501G and 7FArepresent a technology “threshold” or “frontier” that is used as a baseline for all other technology comparisons. For the purpose of this analysis this “threshold” will be referred to as the Phase 1 selection. To the extent other technologies costs of operation and emissions profile are below this technology frontier they would be preferable. To the extent emissions and costs of a technology are both higher, the technology is not considered a candidate for the next step in the planning process, the development of alternative resources plans for more detailed analysis.

Exhibit 8-6 New Replicable Resource Located On Long Island – Phase 1



8.5 Phase 2 – New Replicable Resource Off-Island

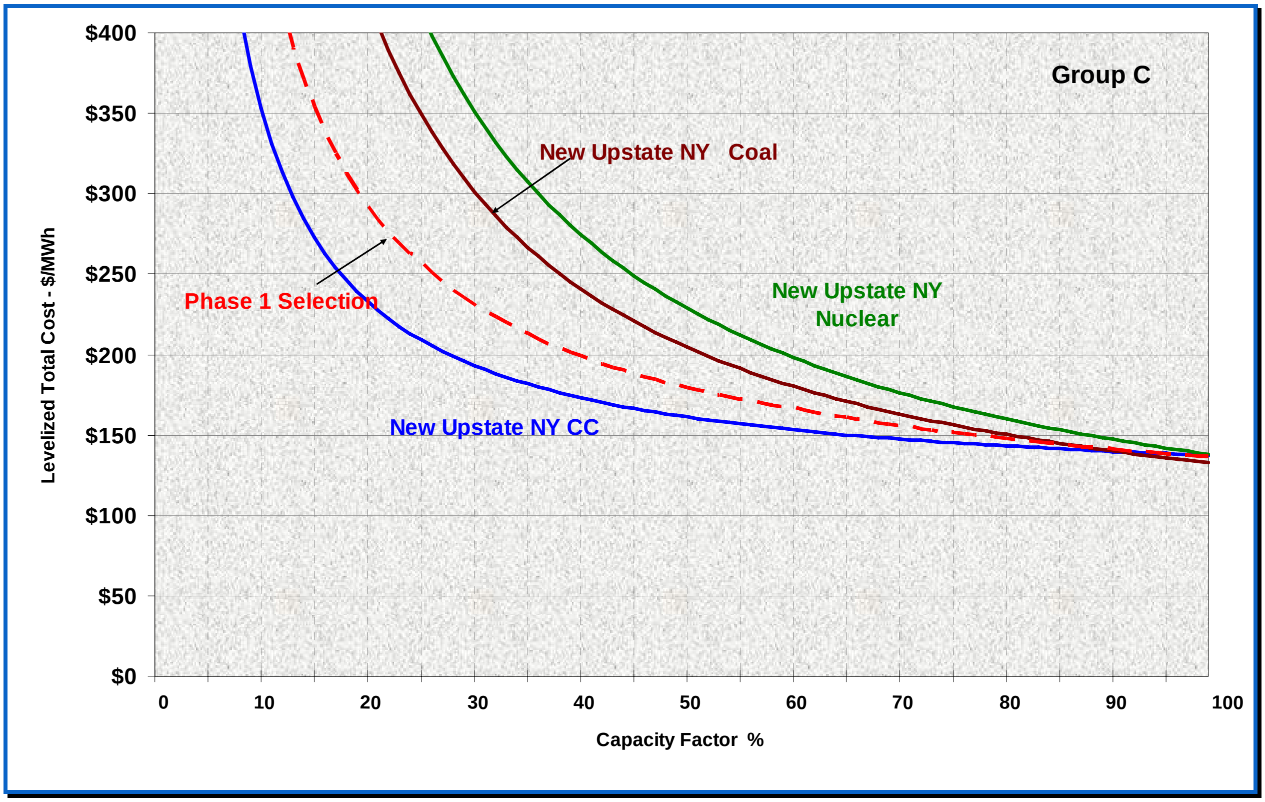
The next series of exhibits analyze the Phase 2 technologies which include new replicable technologies potentially to be located off Long Island. This includes Groups C through G.

- Group C: Upstate NY New Nuclear, Coal, or CC with transmission congestion costs
- Group D: PJM Cable II RB, PJM Cable II UDR, NUSCO Upgrade 1, NUSCO Upgrades 1&2
- Group E: Merchant Upstate NY Cable with New Nuclear, Coal, CC, or Energy
- Group F: NYPA Upstate NY Cable with New Nuclear, Coal, CC, or Energy
- Group G: PJM Cable II with New Nuclear, Coal, or CC

8.5.1 Group C

The composite Phase 1 Selection curve is depicted in Exhibit 8-7 as a dashed red line along with the Group C technologies. Group C represents new conventional replicable technologies potentially to be located off Long Island in upstate New York. They include coal, nuclear and combined cycle technologies all of which would incur substantial transmission congestion costs in order to deliver energy to the Long Island market.

Exhibit 8-7 New Replicable Resource Located Off Long Island – Group C



ICAP MW	Name	Levelized Cost				Environmental Emissions		
		Capacity $/kW-mo	Energy $/MWh	Capacity Factor	Total $/MWh	CO2 lb/MWh	NOx lb/MWh	SO2 lb/MWh
500	New Upstate NY Coal	$72.35	$28.49	86%	$144.08	1941	0.6440	1.2900
502	New Upstate NY CC	$36.95	$82.21	82%	$142.60	828	0.0575	0.0042
1350	New Upstate NY Nuclear	$86.89	$14.33	88%	$149.52	0	0.0000	0.0000

Results show that combined cycle technology has a clear economic advantage over both coal and nuclear technologies at capacity factors below 90%. An advantage that becomes more pronounced as the capacity factor is reduced. At capacity factors above 90% the economics of coal, nuclear and combined cycle technologies tend to merge together, with new nuclear having an emissions advantage over the other fossil fuel burning technologies and new coal having a very small economic advantage.

8.5.2 Group D

Exhibit 8-8, Group D expands the comparison group to include transmission options. A second 660 MW HVDC interconnection with PJM was evaluated. The connection point on Long Island was evaluated at the Far Rockaway plant site. The planned conversion of the existing Valley Stream – Hewlett – Far Rockaway 33 kV circuit to 69 kV together with the two existing Valley Stream – Far Rockaway 69 kV circuits would facilitate a new 660 MW HVDC interconnection at Far Rockaway. This second 660 MW HVDC line was evaluated as providing its entire capacity to LIPA. The alternatives for this second HVDC line from PJM are summarized as follows:

1. PJM Cable II, UDR - A second 660 MW HVDC line from PJM with LIPA claiming capacity deliverability rights or UDR(s)
2. PJM Cable II, RB - A second 660 MW HVDC line from PJM with LIPA claiming reliability benefits or RB(s)

Two cable upgrade alternatives to Connecticut were also studied. In 2008 LIPA replaced the oil-filled cables that ran from Northport to Norwalk Harbor (NUSCO Cable) built in 1969 with a new solid dielectric cable. This new cable system is designed to be more reliable and more environmentally friendly than the original cable. Both the new and the old cable were rated at 300 MVA or 286 MW. However, constraints on the land based transmission system limit imports to 200 MW.

1. NUSCO Upgrade 1 – would improve the transmission system to remove the land-based constraints and allow operation up to 286 MW. The result would be a net increase of 86 MW of import capability.
2. NUSCO Upgrades 1 and 2 (combined)– would reconfigure the existing cable system[1] to increase transfer capability up to 450 MVA (429 MW). Land based transmission constraints would also be removed to allow the 429 MVA to be delivered to and from Long Island. The net increase of capacity would be for an incremental increase of 143 MW over Option 1 for a total of a 229 MW increase from Options 1 and 2 combined.

The NYISO provides the option of claiming a cable as either a UDR or RB on an annual basis. This distinction is purely financial and has nothing to do with the technology of the cable. When a cable is claimed as a UDR, it has to be “backed up” by firm capacity and it is then specifically reserved as a “LIPA only” resource for purposes of meetings its reliability requirement. When a cable is claimed as a RB, it doesn’t have to be “backed up” with firm capacity, and would in effect share the benefit of the cable with the NYISO as a whole. Overall LIPA’s reserve requirements are less when claiming the cable as a UDR. Because it results in a deferral of the need to build or procure additional resources, the UDR option is a financially more attractive alternative. When comparing the second PJM cable options to the Phase 1 Selection benchmark, the PJM II UDR option is more economic for capacity factors above 55% and merits more detailed review.

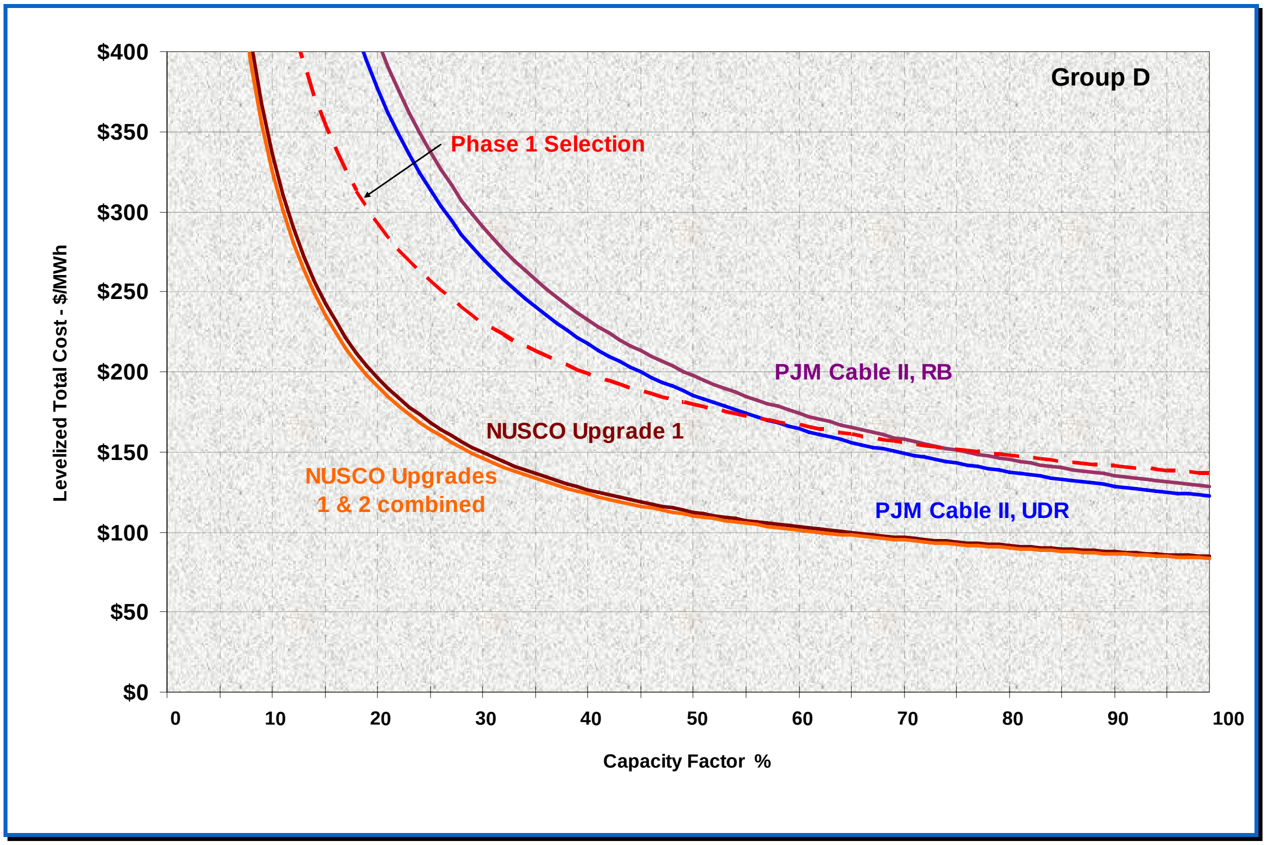
The NUSCO alternatives compare very favorably in this comparison group. NUSCO Upgrade 1 as well as NUSCO Upgrades 1 and 2 (combined) are both less costly across the entire range of assumed capacity factors. Both NUSCO Upgrade options remain strong candidates for more detailed analysis. At higher capacity factors, a PJM Cable II is more cost effective than the Phase 1 selection group. However, the

[1] A back-up cable would be used for normal power transfers. In the event that one cable failed, transfer capability would revert to 300 MVA.

projected capacity factor for this option is less than the level at which the second cable becomes economic.

Emissions have not been factored into the screening analysis for these Group D alternatives because the cables in this comparison group do not directly produce emissions. More detailed assessments in section 9 capture the environmental impacts of importing power over these cables.

Exhibit 8-8 New Replicable Resource Located Off Long Island – Group D

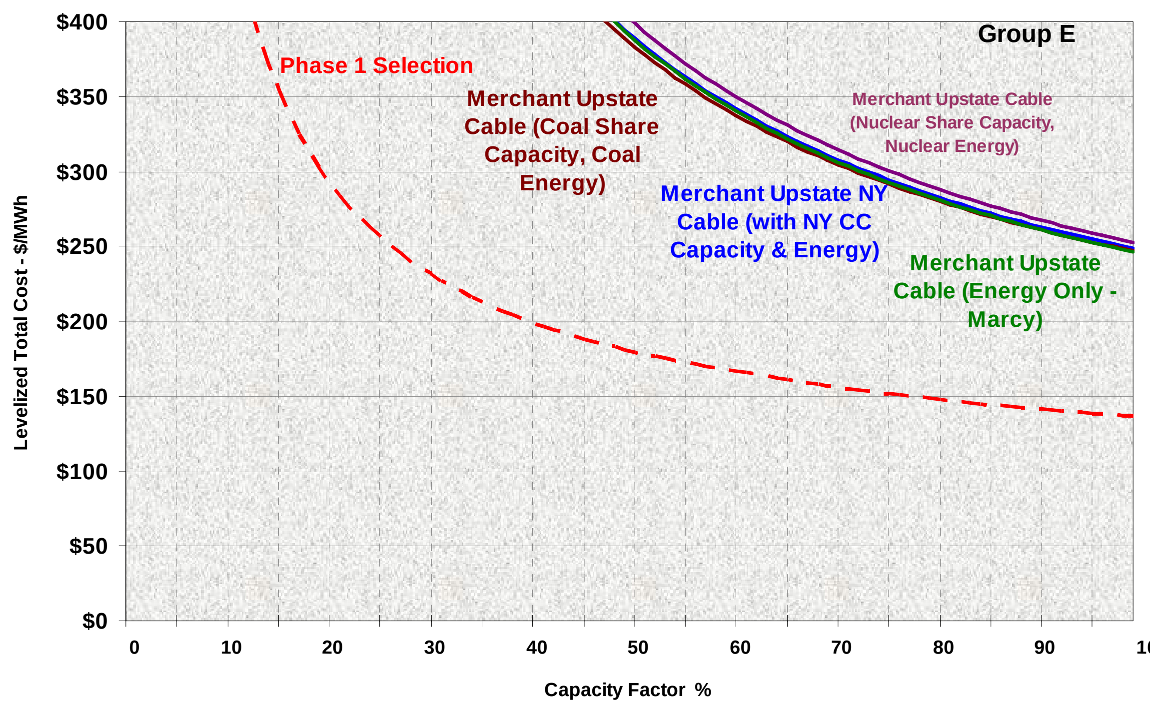


ICAP MW	Name	Levelized Cost				Environmental Emissions		
		Capacity $/kW-mo	Energy $/MWh	Capacity Factor	Total $/MWh	CO2 lb/MWh	NOx lb/MWh	SO2 lb/MWh
86	NUSCO Upgrade 1	$22.22	$56.46	50%	$112.45	0	0.0000	0.0000
229	NUSCO Upgrades 1 and 2 (combined)	$21.35	$56.46	50%	$110.25	0	0.0000	0.0000
1038	PJM Cable II, RB	$55.47	$57.79	45%	$214.79	0	0.0000	0.0000
1038	PJM Cable II, UDR	$46.66	$57.79	45%	$201.33	0	0.0000	0.0000

8.5.3 Group E

Exhibit 8-9, Group E, represents new conventional replicable technologies potentially to be located off Long Island in upstate New York combined with transmission improvements to deliver the power to Long Island. Similar to Group C, this Group includes coal, nuclear and combined cycle technologies. The difference is in the manner in which the transmission requirements are treated. In previously presented Group C, it is assumed that the existing transmission infrastructure is adequate to provide the needed throughput to deliver energy to Long Island and that the only implication for LIPA would be increased costs due to transmission congestion penalties that would be incurred in the process. Group E assumes the transmission infrastructure is not adequate and that additional transmission infrastructure construction would be necessary in order to deliver energy to the Long Island market. In addition Group E also includes a transmission only option which would take advantage of lower cost energy available in upstate New York.

Exhibit 8-9 New Replicable Resource Located Off Long Island – Group E



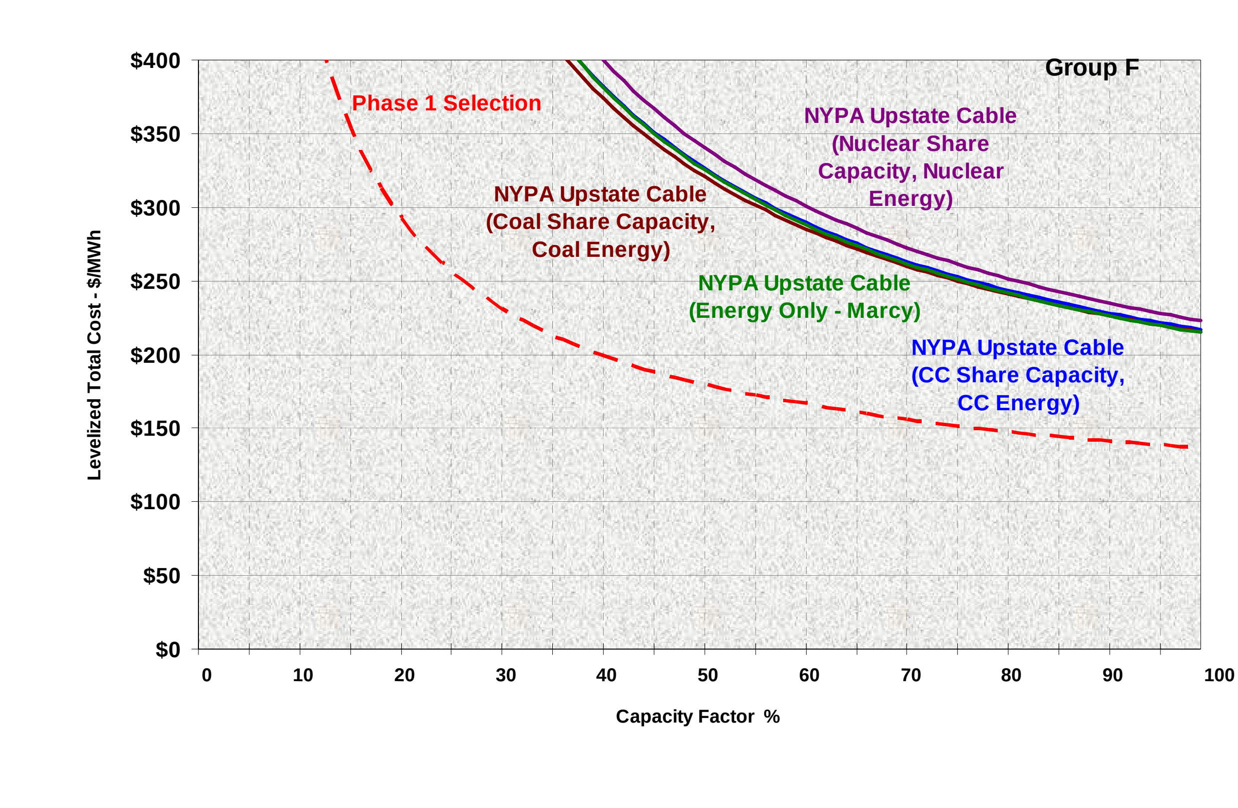
ICAP MW	Name	Levelized Cost				Environmental Emissions		
		Capacity $/kW-mo	Energy $/MWh	Capacity Factor	Total $/MWh	CO2 lb/MWh	NOx lb/MWh	SO2 lb/MWh
345	Merchant Upstate NY Cable – Energy Only	$113.39	$102.18	45%	$423.13	0	0.0000	0.0000
345	Merchant Upstate NY Cable + New Nuclear	$163.69	$22.86	88%	$258.75	0	0.0000	0.0000
345	Merchant Upstate NY Cable + New Coal	$147.56	$40.13	86%	$252.79	1941	0.6440	1.2900
345	Merchant Upstate NY Cable + New CC	$109.95	$96.07	82%	$254.52	828	0.0575	0.0042

The results in Exhibit 8-9 clearly show that the economics of the additional merchant transmission infrastructure makes this group a very unattractive alternative as compared to building generation locally on Long Island. The Merchant Upstate NY Cable – Energy Only alternative is particularly unattractive on a dollar per megawatt-hour basis with a total cost nearly double that of the other alternatives in this comparison group as shown in the Exhibit 8-9 table. This cost differential is driven largely by the much lower capacity factor associated with the cable only alternative. None of these alternatives merit further detailed analysis.

8.5.4 Group F

Exhibit 8-10 compares the same group of alternatives as in Exhibit 8-9 with one variation. In this group the new transmission infrastructure is assumed to be built by NYPA. The lower cost of capital available to NYPA has the effect of lowering the capital costs of these alternatives as a group. However, while the costs have been reduced, these alternatives are still not cost competitive in comparison to the Phase 1 Selection alternatives discussed previously.

Exhibit 8-10 New Replicable Resource Located Off Long Island – Group F

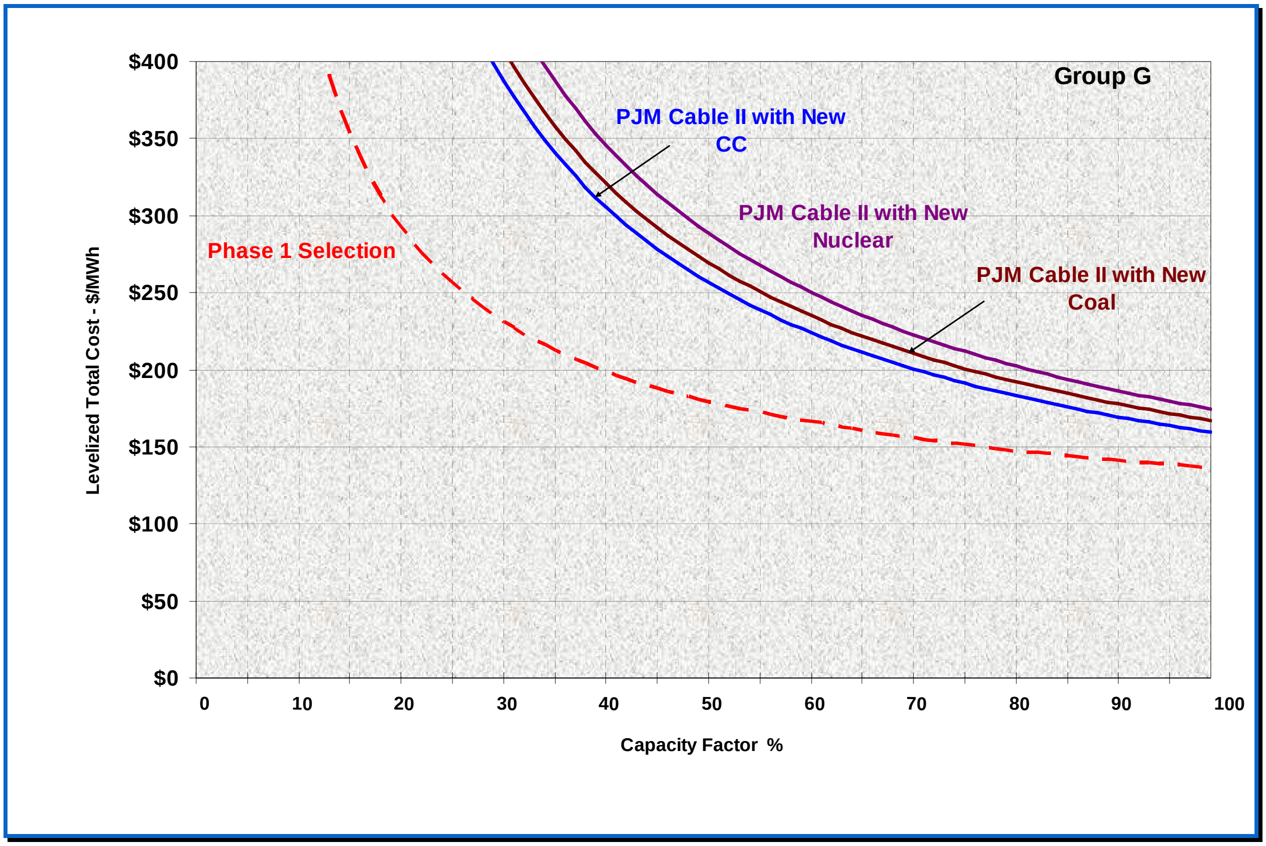


ICAP MW	Name	Levelized Cost				Environmental Emissions		
		Capacity $/kW-mo	Energy $/MWh	Capacity Factor	Total $/MWh	CO2 lb/MWh	NOx lb/MWh	SO2 lb/MWh
345	NYPA Upstate NY Cable – Energy Only	$88.59	$102.18	45%	$352.94	0	0.0000	0.0000
345	NYPA Upstate NY Cable + New Nuclear	$140.87	$24.95	86%	$227.97	0	0.0000	0.0000
345	NYPA Upstate NY Cable + New Coal	$124.75	$40.13	86%	$219.91	1941	0.6440	1.2900
345	NYPA Upstate NY Cable + New CC	$87.13	$96.07	82%	$221.64	828	0.0575	0.0042

8.5.5 Group G

Exhibit 8-11, Group G looks at the option of building new generation in the PJM region and importing the power over a second PJM transmission interconnection. Technologies are the same as in Exhibit 8-8, the only difference is the location of the generation.

Exhibit 8-11 New Replicable Resource Located Off Long Island – Group G



ICAP MW	Name	Levelized Cost				Environmental Emissions		
		Capacity $/kW-mo	Energy $/MWh	Capacity Factor	Total $/MWh	CO2 lb/MWh	NOx lb/MWh	SO2 lb/MWh
1038	PJM Cable II with New CC	$111.92	$14.91	88%	$189.83	0	0.0000	0.0000
1038	PJM Cable II with New Coal	$96.04	$30.80	88%	$180.90	1941	0.6440	1.2900
1038	PJM Cable II with New Nuclear	$57.76	$82.21	77%	$172.49	828	0.0575	0.0042

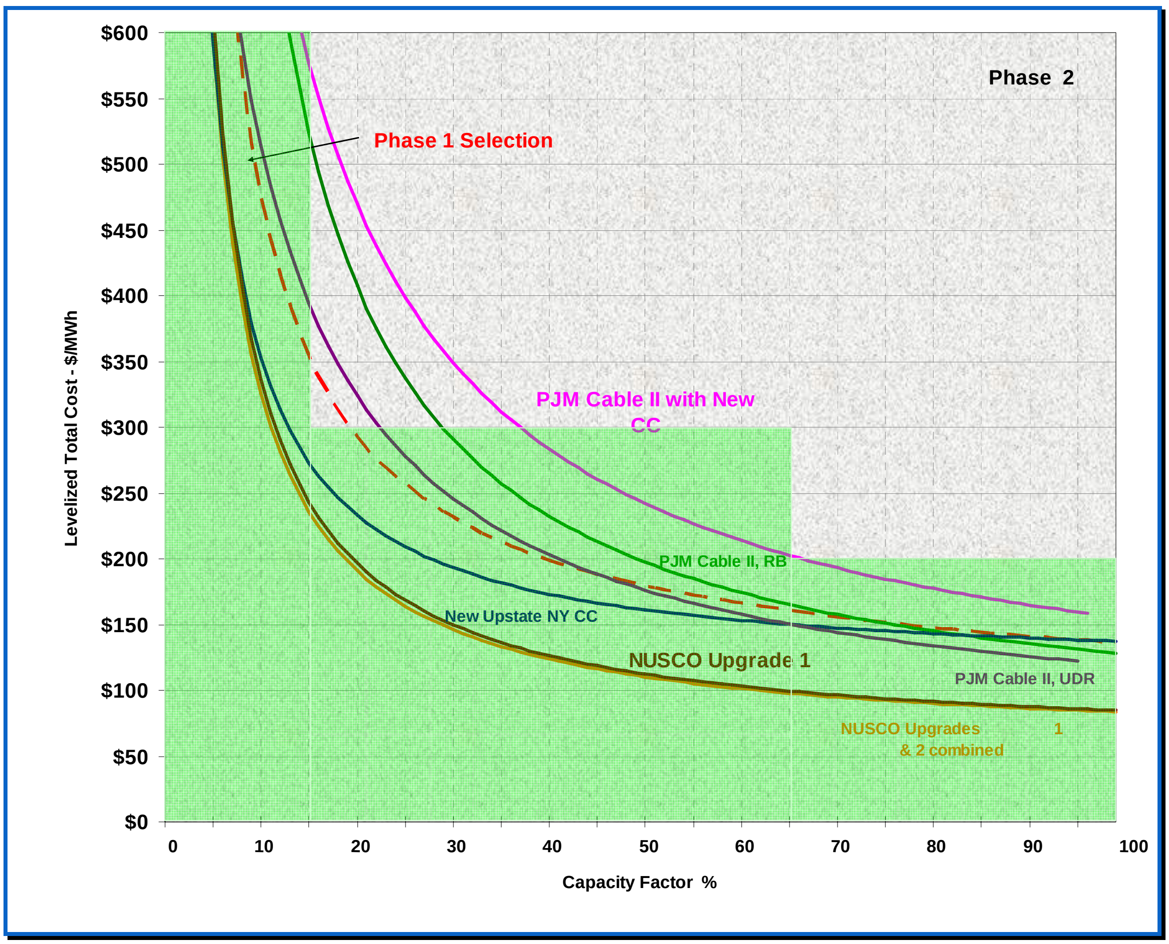
The results are consistent with the previous exhibits that looked at building generation in Upstate New York. Once again the cost of building generation and the required additional transmission exceeds any potential benefit that may be derived from lower costs of labor and fuel pricing that may be available off Long Island.

8.5.6 Phase 2 Summary

Exhibit 8-12 summarizes the results for this phase of the screening analysis by comparing the levelized cost of each alternative across a range of assumed capacity factors. The green shaded area loosely categorizes the range of capacity factors as peaking (<15%), intermediate (15-65%) or base load (>65%) for comparative purposes. When comparing the new replicable resource alternatives potentially to be located off Long Island in Phase 2 against the Phase 1 Selection technologies located on Long Island the alternatives that merit further analysis are as follows:

- Upstate New York Combined Cycle (congestion pricing)
- NUSCO Upgrade 1
- NUSCO Upgrade 1 & 2
- Second PJM Cable

Exhibit 8-12 New Replicable Resource Located Off Long Island – Phase 2



8.6 Phase 3 New Limited Resource Located On-Island

Phase 3 of the screening analysis addresses new limited resources located on Long Island. The term limited as used here describes the somewhat constrained ability to expand these resources indefinitely. The following table lists the technologies and the associated groupings in Phase 3.

- Group H: Energy Efficiency Technologies – CEI, ELI Base, ELI Advance, Automated Meter Initiative
- Group I: Wind and Solar Technologies – Off-shore Long Island Wind Farm, On-Long Island Wind Turbine, Long Island Solar Roof, PJM II New Wind, Upstate NY New Wind, Merchant Upstate NY Cable with New Wind, NYPA Upstate NY Cable with New Wind, PJM Cable II with New Wind
- Group J: Other Renewable Technologies – Landfill Gas, On-Island Fuel Cell, Refuse, East Hampton Biofuel, Barrett Steam Biofuel, New CT Biofuel, Shoreham CT Biofuel

8.6.1 Group H

Exhibit 8-13, Group H compares the cost of the existing Clean Energy Program, Efficiency Long Island Base and Advanced Programs, and the Automated Metering Infrastructure development effort against the Phase 1 Selection technologies.

Advanced Meter Infrastructure (AMI) offers the promise of revolutionary improvements in the accessibility of information to both electric customers and utilities. Meter reading, load control, customer response, outage tracking and restoration are just a few of the potential benefits.

The Clean Energy Initiative (CEI), LIPA's first major energy efficiency program, was a ten year program from 1998 through 2008 and demonstrated LIPA's commitment to demand side management. CEI included programs for customers, distributors, and energy service companies, so that appropriate delivery markets would develop in support of the initiative. Over the course of these past 10 years, CEI resulted in:

- Installations of more than 42,600 high efficient central air conditioning units;
- More than 1,600 customers installing photovoltaic systems through participation in its Solar Pioneer Program; and
- Over 750 Energy Star® homes built on Long Island through LIPA's program delivery and incentives.

CEI achieved demand reductions of 170 MW at times of peak demand when the cost of electricity generation is the highest. Also, CEI's energy savings of 701 GWh resulted in emissions savings of more than 1.5 million tons of CO_2, over 2,110 tons of NO_X, and more than 5,560 tons of SO_2. The energy savings to date translate into an equivalent fuel savings of more than 3.9 million barrels of oil, or more than 24 million dekatherms of gas.

Efficiency Long Island (ELI) is a ten year comprehensive energy efficiency program that builds upon and expands efficiency programs and is one component that can support New York's 15 x 15 energy efficiency goals. ELI differs from the LIPA's earlier approach by targeting the continued achievement of energy savings in the new construction process while also targeting the significant energy efficiency potential in retrofitting and upgrading existing homes and businesses. ELI is comprised of six initiatives as described below:

1. Efficiency Products – incentivizes the purchase of Energy Star® or other high efficiency lighting, appliances, consumer electronics and pool pumps by residential customers from retail outlets.

2. Energy Star® Labeled Homes – promotes efficient building shell structures, HVAC, hot water, duct sealing, lighting and high efficiency appliance upgrades beyond the New York State Building Code in new residential construction.

3. Existing Homes – rebates and incentives for duct sealing and tune-ups for central air conditioners, whole house retrofit assistance through certified efficiency contractors, addresses low-income households through Residential Energy Affordability Program (REAP) and other enhanced efforts. Provides incentives for properly installed higher-than-code efficiency central air and heat pump equipment.

4. C&I New Construction – rebates and incentives for comprehensive improvements in efficiency in construction of all new buildings and major renovations through the use of technical experts and financial incentives provided via the program.

5. C&I Existing Buildings – rebates and incentives for increasing efficiency of equipment purchases stemming from natural replacement at the end of useful life and promoting early retrofits, or discretionary replacement of functioning inefficient equipment prior to the end of its useful life, in existing facilities.

6. LEED Ratings – Both C&I new construction and existing buildings may apply for Leadership in Energy and Environmental Design (LEED) Rating System incentives that are designed to move the building community towards a focus on environmentally friendly and sustainable buildings. LIPA's incentives include commissioning services, building modeling and LEED energy points.

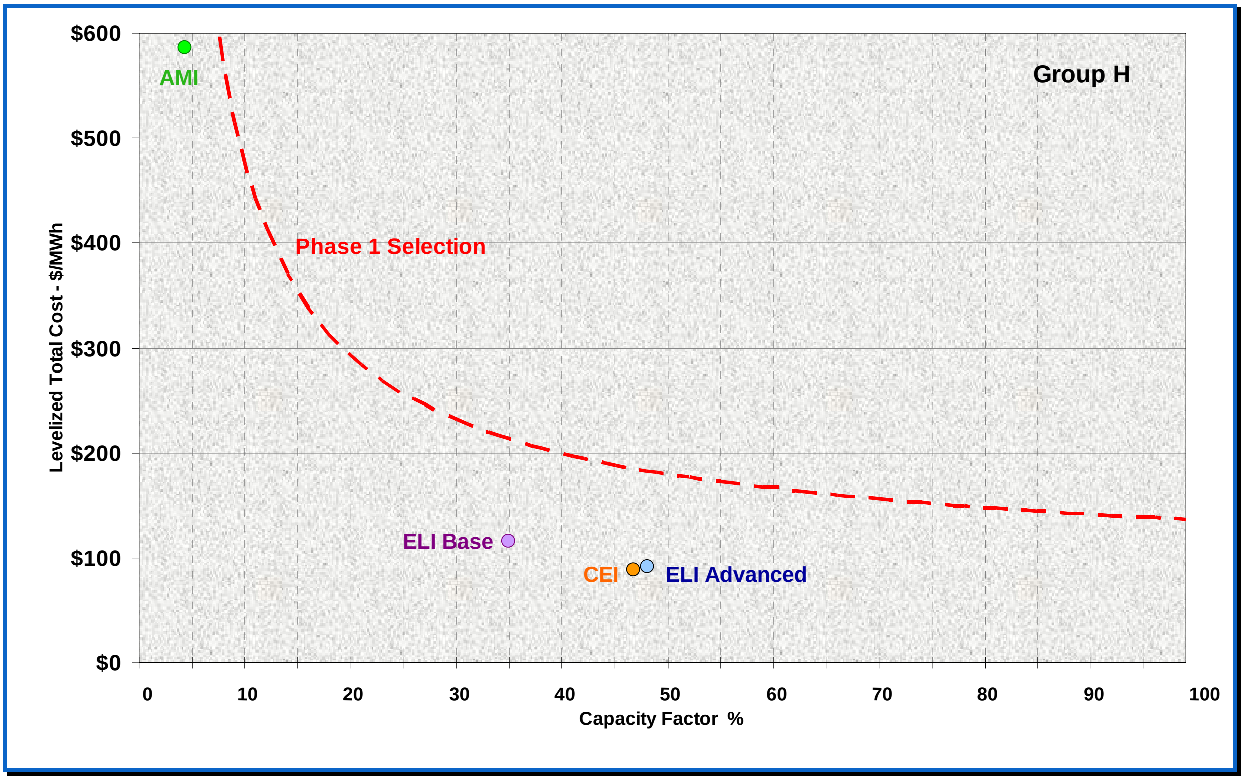
As shown in Exhibit 8-13 all technologies in this Group offer the benefit of zero direct combustion emissions (i.e. CO_2, NO_X and SO_2). On a cost basis as a group they offer lower costs than the Phase 1 Selection alternatives.

While programs such as ELI hold much promise and are significant in their forecasted contribution toward deferring the need for additional resources they will likely need to be supplemented in order to meet LIPA's need for electricity in the long run. All programs in this group merit additional more detailed analysis.

Because of the promise AMI holds, LIPA has already begun implementation of two AMI pilot installations in 2008 which will continue in 2009. Installations are located at residential and commercial customer sites, with each pilot program consisting of about 100 meters at the Hauppauge industrial park and the Bethpage area. LIPA intends to continue to investigate the opportunities that may result from the introduction of AMI system wide through its pilot programs and by assessing the implications when complete.

Similarly, in 2008, LIPA's Board of Trustees announced the approval of the ELI Program. The program began implementation on January 1, 2009.

Exhibit 8-13 New Limited Resource Located On Long Island – Group H



ICAP MW	Name	Levelized Cost				Environmental Emissions		
		Capacity $/kW-mo	Energy $/MWh	Capacity Factor	Total $/MWh	CO_2 lb/MWh	NOx lb/MWh	SO_2 lb/MWh
156	Automated Meter Initiative (AMI)	$15.19	$ 0	4%	$584.36	0	0.0000	0.0000
200	Clean Energy Initiative (CEI)	$26.09	$ 0	47%	$87.66	0	0.0000	0.0000
813	ELI Base - Block 8	$21.37	$ 0	35%	$115.89	0	0.0000	0.0000
316	ELI Advanced – Block 10	$29.56	$ 0	48%	$96.56	0	0.0000	0.0000

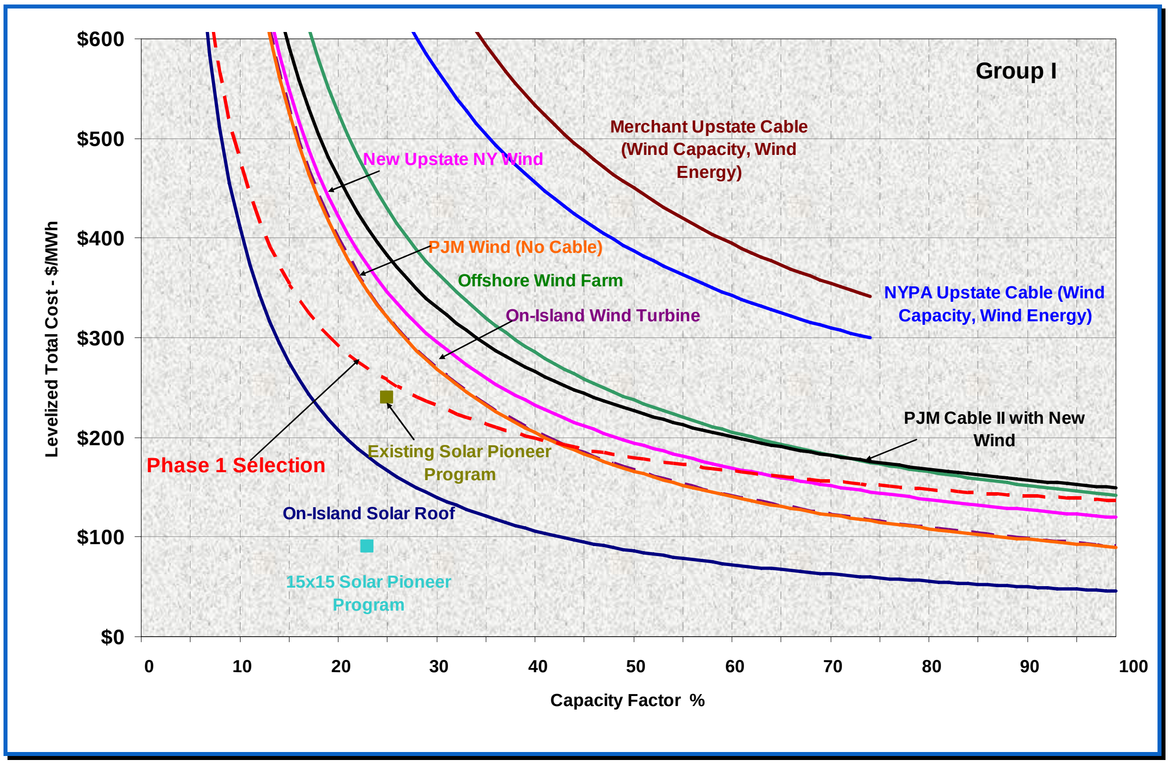
8.6.2 Group I

Exhibit 8-14, Group I, compares solar resources and new wind resources located on and off Long Island in multiple combinations of location and ownership. The wind resources are analyzed assuming alternate locations; PJM Interconnection, off-shore Long Island, Upstate New York, and on-shore Long Island. Two different ownership assumptions, merchant and NYPA, were considered for the required new transmission infrastructure associated with the Upstate New York alternatives.

As with the alternatives in Group H, the renewable alternatives in this group offer the advantage of zero combustion emissions.

In order to understand the cost implications it is important to focus attention on the viable operating range or capacity factor for this group of technologies. As a class, these technologies have the potential to make a significant impact on LIPA's need for additional resources; however, it is equally important to keep in mind their intermittent nature and inability to operate at capacity factors above 30% on an annual basis. Focusing on the 0-30% capacity factor range in Exhibit 8-14, it is evident that only a few of the alternatives studied are cost effective in comparison to the Phase 1 Selection alternatives. Specifically, the Solar Pioneer programs and the on-Island Solar Roof initiative show the greatest potential benefit to LIPA. Due to the size of LIPA's RPS targets and CO_2 footprint targets, additional renewable resources are likely to be needed in LIPA's renewable energy mix. As a result, the off-shore wind alternative are also considered as a measure to help reach RPS and CO_2 footprint targets.

Exhibit 8-14 New Limited Resources Located On and Off Long Island – Group I



ICAP MW	Name	Levelized Cost				Environmental Emissions		
		Capacity $/kW-mo	Energy $/MWh	Capacity Factor	Total $/MWh	CO2 lb/MWh	NOx lb/MWh	SO2 lb/MWh
1	Existing Solar Pioneer Program	$29.56	$ 0	26%	$240.43	0	0.0000	0.0000
150 / 38	15x15 Solar Pioneer Program	$12.68	$ 0	24%	$90.15	0	0.0000	0.0000
150 / 38	On-Island Solar Roof	$29.58	$4.94	15%	$274.92	0	0.0000	0.0000

160 / 38	PJM Cable II, Wind	$58.58	$68.07	25%	$158.18	0	0.0000	0.0000
160 / 38	On-Island Wind Turbine	$225.90	$12.17	25%	$321.44	0	0.0000	0.0000
150 / 38	New Upstate NY Wind	$244.00	$12.17	25%	$346.23	0	0.0000	0.0000
150 / 38	PJM Wind (No Cable)	$224.98	$12.17	25%	$320.19	0	0.0000	0.0000
150 / 38	Merchant Upstate Cable (Wind Capacity & Energy)	$130.07	$104.48	25%	$291.93	0	0.0000	0.0000
150 / 38	NYPA Upstate Cable (Wind Capacity & Energy)	$107.26	$104.48	25%	$259.05	0	0.0000	0.0000
144 / 50	Offshore Wind Farm	$200.71	$45.11	36%	$314.83	0	0.0000	0.0000

8.6.3 Group J

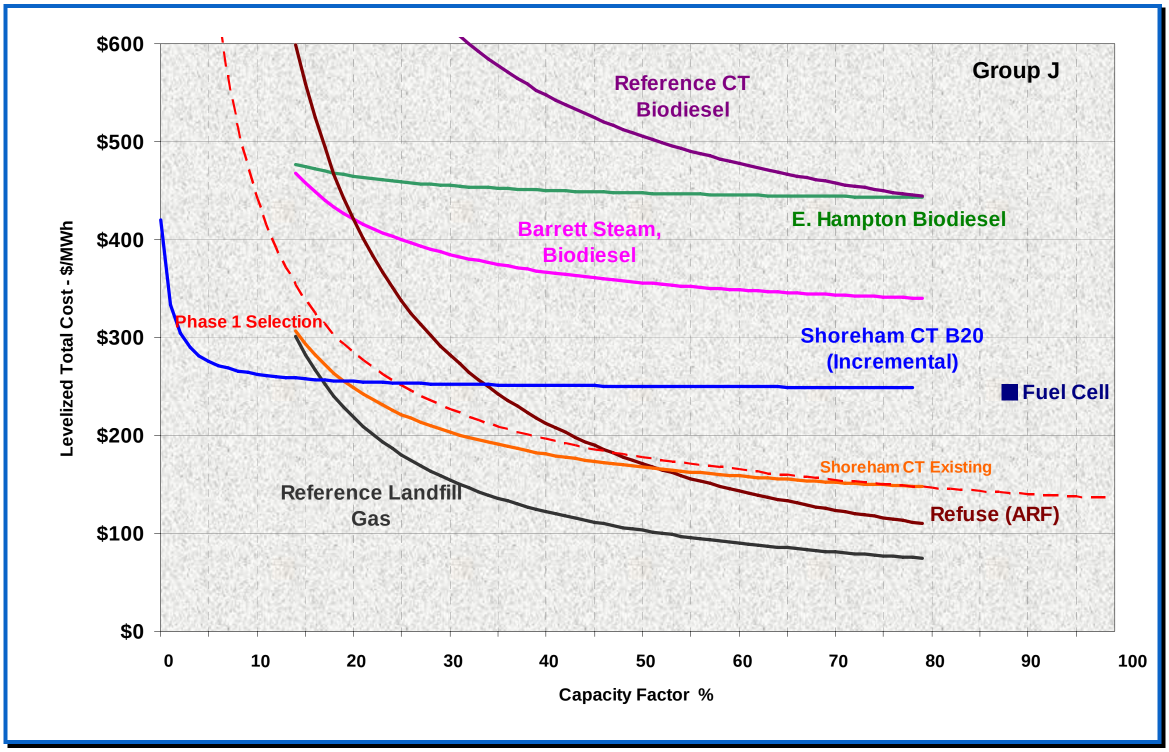
Exhibit 8-15, Group J compares landfill gas, fuel cell, refuse and biofuel generation alternatives. Landfill gas is the lowest cost resource in this group, driven largely by lower capital requirements and fuel costs. However, the number of available untapped landfills on Long Island is very limited.

Biofuels have the advantage of lower emissions rates (20% reduction in NO_X and SO_2) in comparison to conventional carbon-based fuels at the expense of somewhat higher fuel costs. The biofuel diesel offers the advantage of a 20% reduction in NO_X and SO_2 emissions by virtue of its 20% mixture of bio-derived fuel.

Benefits from burning biofuel at East Hampton are minimized by the very low, 1% annual capacity factor at which it would project to operate. At Barrett Steam, the benefits are greater than East Hampton, but are sill not attractive. The cost and emissions profile for the Reference CT Biodiesel in this analysis is based on a 10 MW Solar Mars machine. Refuse is shown as cost effective at capacity factors above 50%, however, at an expected operating level well below 50%, this option is not attractive.

The Shoreham CT is the most attractive alternative for biofuel, it provides the best combination efficiency and capacity factor in comparison to the other CT's in this group. Based on these results the only alternatives that merit further more detailed analysis are the Shoreham CT on biofuel and the landfill gas resource.

Exhibit 8-15 New Limited Resource Located On Long Island – Group J



ICAP MW	Name	Levelized Cost				Environmental Emissions		
		Capacity $/kW-mo	Energy $/MWh	Capacity Factor	Total $/MWh	CO2 lb/MWh	NOx lb/MWh	SO2 lb/MWh
80	Shoreham CT Existing	$19.72	$113.48	9%	$413.40	1137	0.0904	0.0066
6	Reference Landfill Gas	$28.12	$ 25.85	25%	$ 179.84	0	0.0887	0.0048
10	Reference CT Biofuel	$61.09	$338.27	2%	$4,520.32	1517	2.8500	0.0123
21	E. Hampton Biofuel	$ 4.23	$435.79	1%	$1,014..27	1410	39.7902	3.0616
118	Refuse (ARF)	$60.76	$ 4.82	6%	$1,391.16	1170	1.9000	0.3000
382	Barrett Steam, Biofuel	$15.91	$312.34	34%	$ 375.84	1018	1.1382	0.0065
38	Shoreham CT B20 (Incremental)	$1.26	$246.80	9%	$266.04	910	0.0723	0.0053
77	Fuel Cell	$65.75	$145.78	89%	$ 244.89	934	0.0000	0.0000

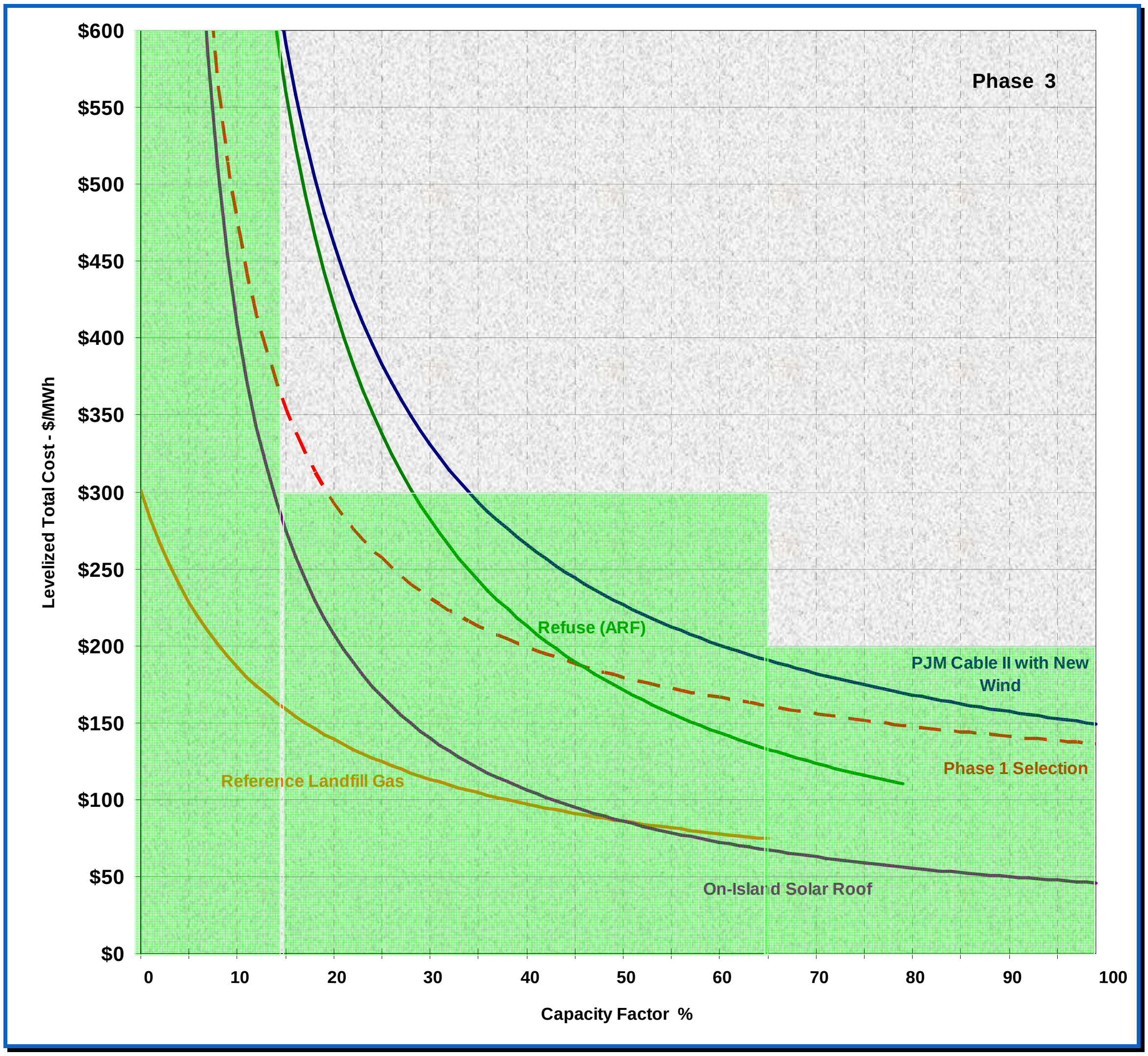
8.6.4 Phase 3 Summary

Exhibit 8-16 summarizes the results for this phase of the screening analysis by comparing the levelized cost of each alternative across a range of assumed capacity factors. When comparing the new limited resource alternatives to be located both on and off Long Island in Phase 3 against the Phase 1 Selection technologies located on Long Island the alternatives that merit further analysis are as follows:

- Automated Metering Infrastructure (AMI)
- Clean Energy Initiative (CEI)
- ELI Base
- ELI Advanced
- Solar Roof
- Solar Pioneer
- Shoreham CT on Biofuel
- Landfill Gas
- On-Island Wind Turbine
- Upstate New York Wind
- PJM Wind
- Offshore Wind

As a group CEI, ELI Base, and ELI Advanced are lower in cost than the majority of future supply based resources available and offer the additional advantage of zero emissions. Landfill gas is the lowest cost resource in this group, driven largely by lower capital requirements and fuel costs. However, the number of available untapped landfills on Long Island is very limited. Similarly solar is also an attractive though limited option that offers the advantage of zero combustion emissions.

Exhibit 8-16 New Limited Resource Located On and Off Long Island – Phase 3



8.7 Phase 4 – Existing Resource Located On-Island

Phase 4 of the screening analysis addresses existing resources located on Long Island. The intent here is to compare existing resources to the Phase 1 Selection alternatives in order to identify resources that may be potential targets for retirement or upgrade. The analysis is focused on determining whether it is more cost efficient to replace or upgrade these units, or to allow their continued operation as currently configured. The technologies and the associated groupings in Phase 4 are listed below.

Group K: Transmission Interconnections – Neptune RB, Neptune UDR, Cross-Sound Cable RB, Cross-Sound Cable UDR

Group L: Steam Unit – Barrett, Northport, Port Jefferson, Far Rockaway, Glenwood, Caithness

Group M: Larger Combustion Turbines – Barrett, Holtsville, Wading River

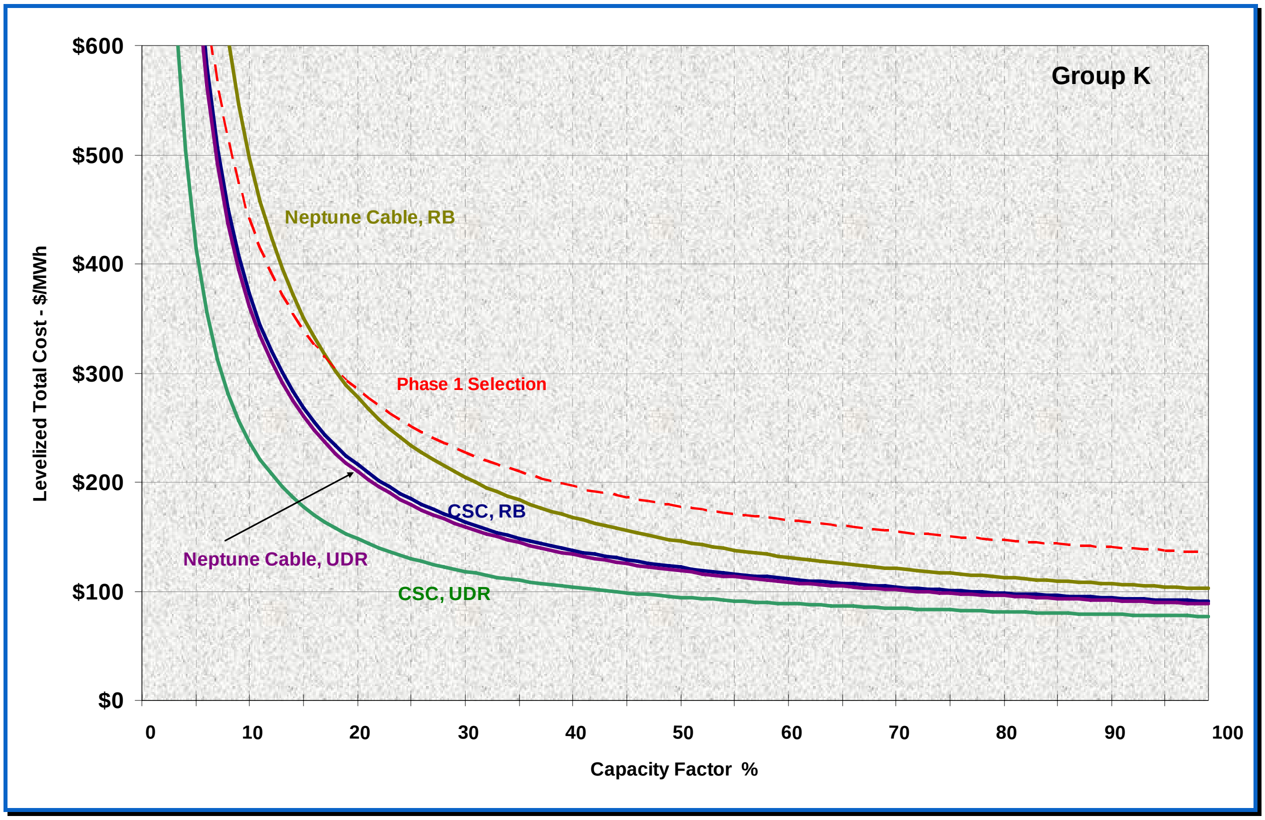
Group N: Smaller Combustion Turbines – Shoreham, East Hampton, Glenwood, Southampton, Southold, West Babylon 4, Northport, Port Jefferson, 2xLM6000 FTU

Group O: Diesel Generators - East Hampton • Montauk

8.7.1 Group K

Exhibit 8-17, Group K compares the cost and emissions profile of the existing Neptune and Cross Sound transmission cables under UDR and RB assumptions against the Phase 1 Selection technologies. Both the Neptune cable to PJM and the CSC to ISO-NE offer cost effective alternatives to LIPA as expected across the entire range of capacity factor assumptions. The lower installed cost of the CSC makes it the lowest cost resource in this comparison group. Consistent with previous discussion, UDRs are once again the choice over RBs for both the Neptune and Cross Sound cables.

Exhibit 8-17 Existing Resource Located On Long Island – Group K

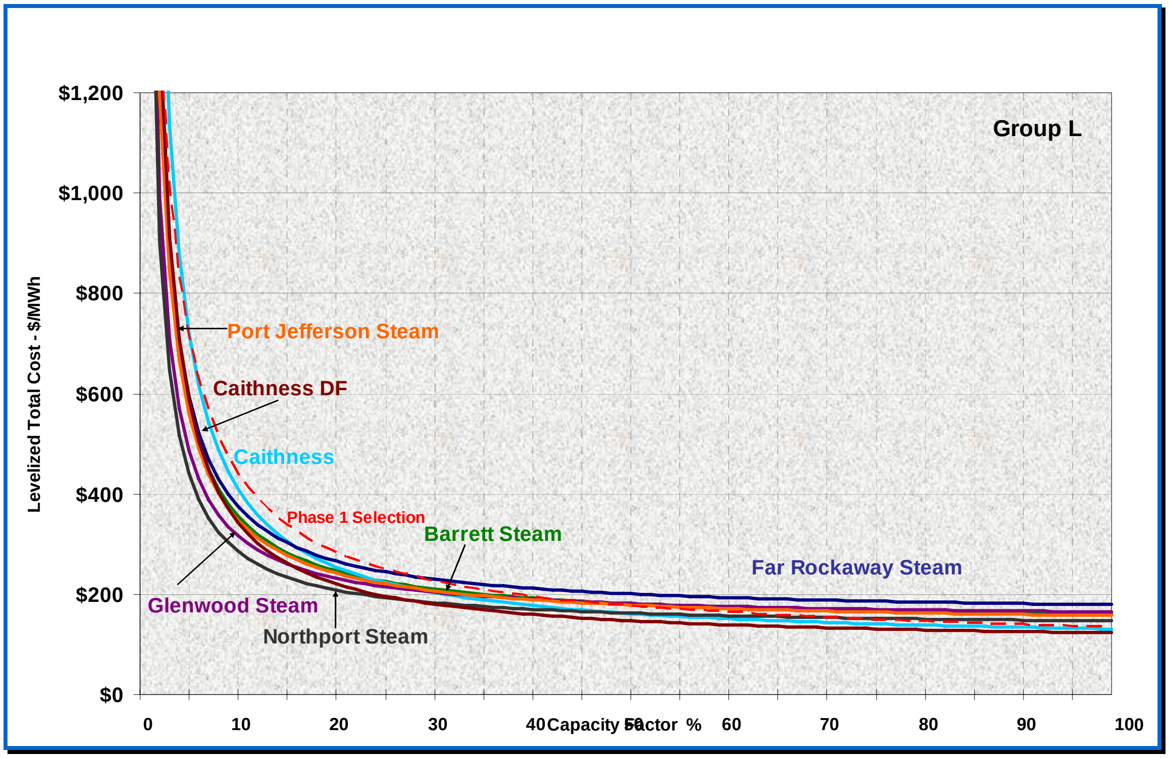


ICAP MW	Name	Levelized Cost				Environmental Emissions		
		Capacity $/kW-mo	Energy $/MWh	Capacity Factor	Total $/MWh	CO2 lb/MWh	NOx lb/MWh	SO2 Lb/MWh
345	Cross-Sound Cable, RB	$24.90	$59.03	65%	$107.27	0	0.0000	0.0000
345	Cross-Sound Cable, UDR	$12.98	$59.03	65%	$ 86.37	1170	1.9000	0.3000
685	Neptune, RB	$34.89	$57.79	89%	$107.16	0	0.0000	0.0000
685	Neptune, UDR	$22.17	$57.79	89%	$ 91.89	0	0.0000	0.0000

8.7.2 Group L

Exhibit 8-16, Group L compares the cost of existing fossil-fired steam resources on Long Island to the cost of the Phase 1 Selection resources. Caithness is the lowest cost resource in this group for capacity factors in excess of 35%. It is also the most recent addition to LIPA's resource portfolio utilizing state-of-the-art combustion turbine technology in a combined cycle configuration. Northport Steam is the most cost effective resource in the 15%-35% capacity factor range. Glenwood and Far Rockaway Steam units are the most cost effective resources for capacity factors below 15%. The Far Rockaway load pocket dictates the limited but necessary operation of this resource, transmission alternatives under evaluation could potentially eliminate the need for this facility. In general, for utilization levels above 35%, existing resources (other than Caithness) are not as cost effective as the newer combined cycle technology alternatives. Below 35% existing steam plant resources are more cost effective than new power plants. This implies that a mix of new and old resources would be most cost effective for most LIPA customers.

Exhibit 8-18 Existing Resource Located On Long Island – Group L



ICAP MW	Name	Levelized Cost				Environmental Emissions		
		Capacity $/kW-mo	Energy $/MWh	Capacity Factor	Total $/MWh	CO2 lb/MWh	NOx lb/MWh	SO2 lb/MWh
36	Caithness DF	$20.15	$98.41	15%	$261.61	1137	0.0904	0.0066
108	Far Rockaway Steam	$15.96	$157.13	7%	$469.28	1350	1.0922	0.0069
230	Glenwood Steam	$12.33	$147.68	15%	$260.23	1396	0.7879	0.0071
271	Caithness	$22.67	$ 99.56	78%	$139.36	859	0.0500	0.0044
382	Barrett Steam	$15.91	$137.94	35%	$200.17	1272	1.1382	0.0065
384	Port Jefferson Steam	$15.49	$136.06	36%	$194.99	1277	1.6326	0.0065
1540	Northport Steam	$11.27	$131.49	28%	$186.61	1275	1.6042	0.0065

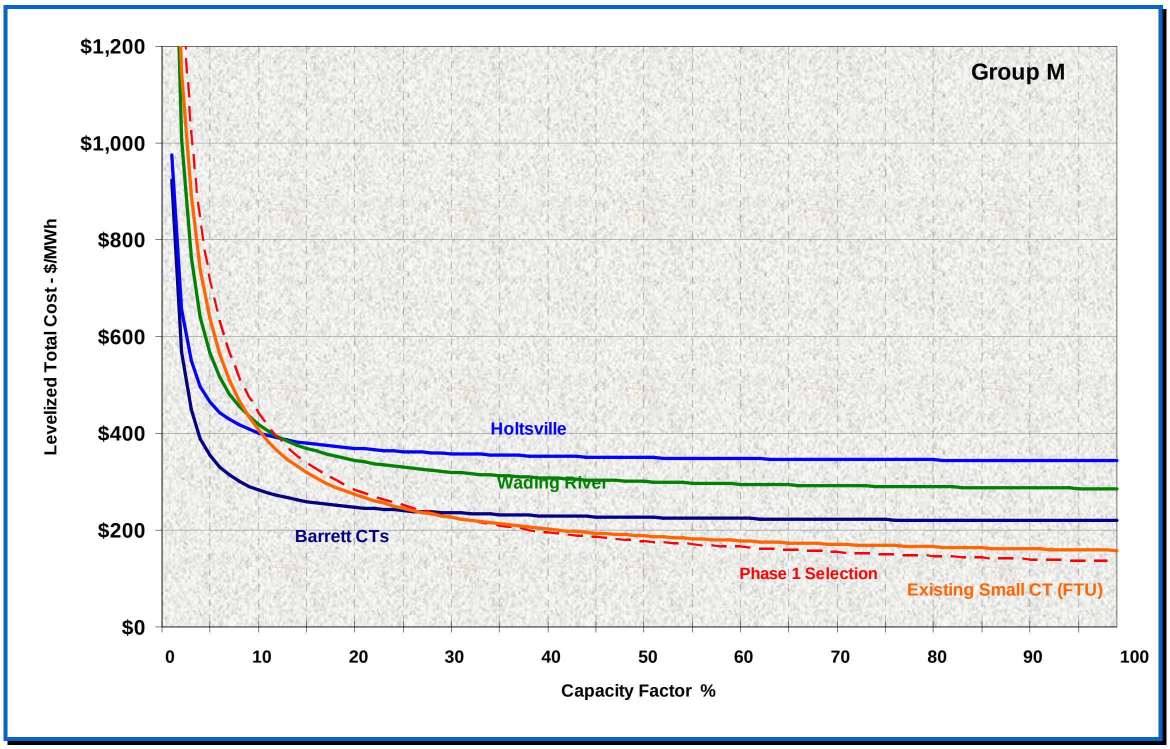
8.7.3 Group M

Exhibit 8-19, Group M compares the cost of the larger existing fossil-fired combustion turbine peaking resources on Long Island to the cost of the Phase 1 Selection resources. With the exception of the newer combustion turbines built in the early 2000s, peaking resources as a class, are high variable cost resources that are not counted on to meet the majority of the LIPA system's energy requirements, but rather they are called upon to generate less than 10% of the time, playing a critical role in meeting customer demand during periods of very high demand or unforeseen system disturbances. In this 10% or less capacity factor range, they are more cost effective than new generation resources from the Phase 1 selection.

Barrett, Holtsville and Wading River are relatively high cost and high emitting resources however in comparison to the other peaking units in the LIPA portfolio they rank favorably, please refer to Exhibits 8-20 and 8-21 for a comparison of the other peaking resources on Long Island.

The new combustion turbines built in the early 2000s are more cost effective than the above units and are competitive against the Phase 1 selection up to a capacity factor of about 30%. The air emissions of these newer units are much lower due to greater efficiency and more advanced pollution control technology.

Exhibit 8-19 Existing Resource Located On Long Island – Group M



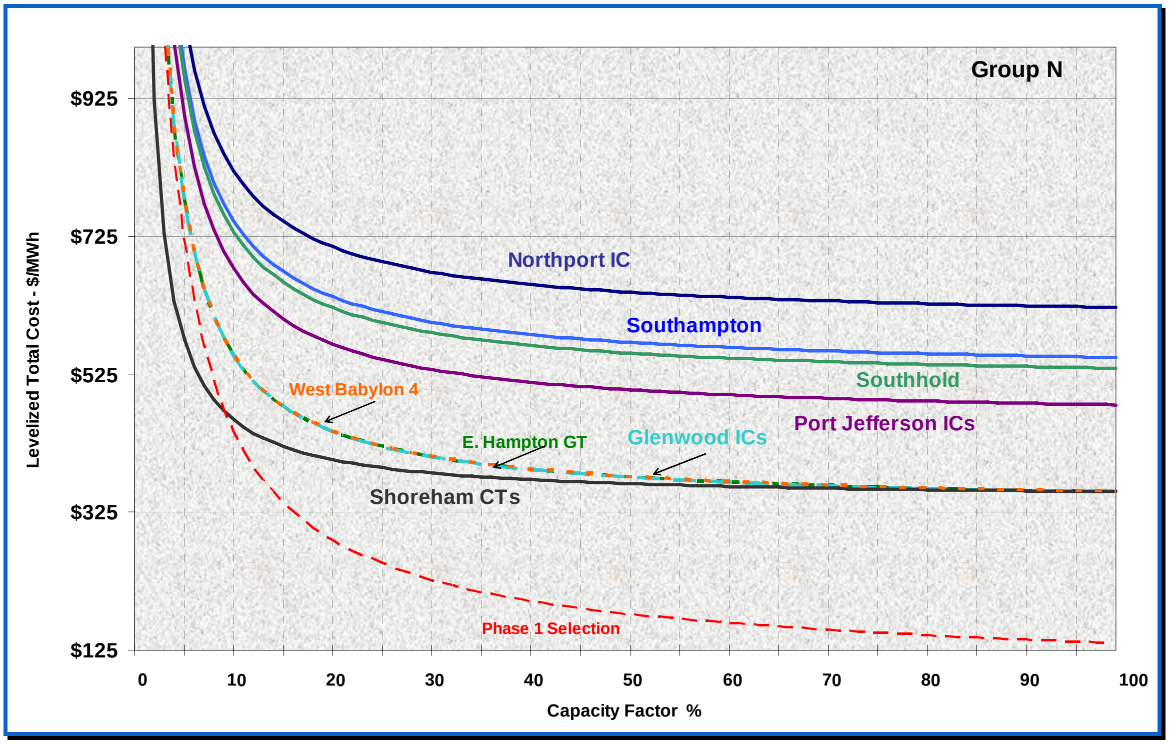
ICAP MW	Name	Levelized Cost				Environmental Emissions		
		Capacity $/kW-mo	Energy $/MWh	Capacity Factor	Total $/MWh	CO2 lb/MWh	NOx lb/MWh	SO2 lb/MWh
270	Wading River	$10.79	$270.81	2%	$1,009.66	2041	2.8387	3.5451
333	Barrett CTs	$ 5.20	$211.94	3%	$ 496.45	1925	9.4577	0.0099
594	Holtsville	$ 4.67	$337.04	1%	$ 975.86	2291	9.4300	4.1596

80	Existing Small CT (FTU)	$22.33	$127.74	9%	$467.49	1137	0.0904	0.0066

8.7.4 Group N

Exhibit 8-20, Group N compares the cost of existing smaller fossil-fired combustion turbine peaking resources on Long Island to the cost of the Phase 1 Selection resources. The small CTs are generally more expensive than Phase 1 selection technologies for capacity factors above 5%. While the newer technologies are less expensive to operate, given the very low 1% capacity factors of these units the total dollars saved will be minimal resulting in very long investment pay back periods.

Exhibit 8-20 Existing Resource Located On Long Island – Group N



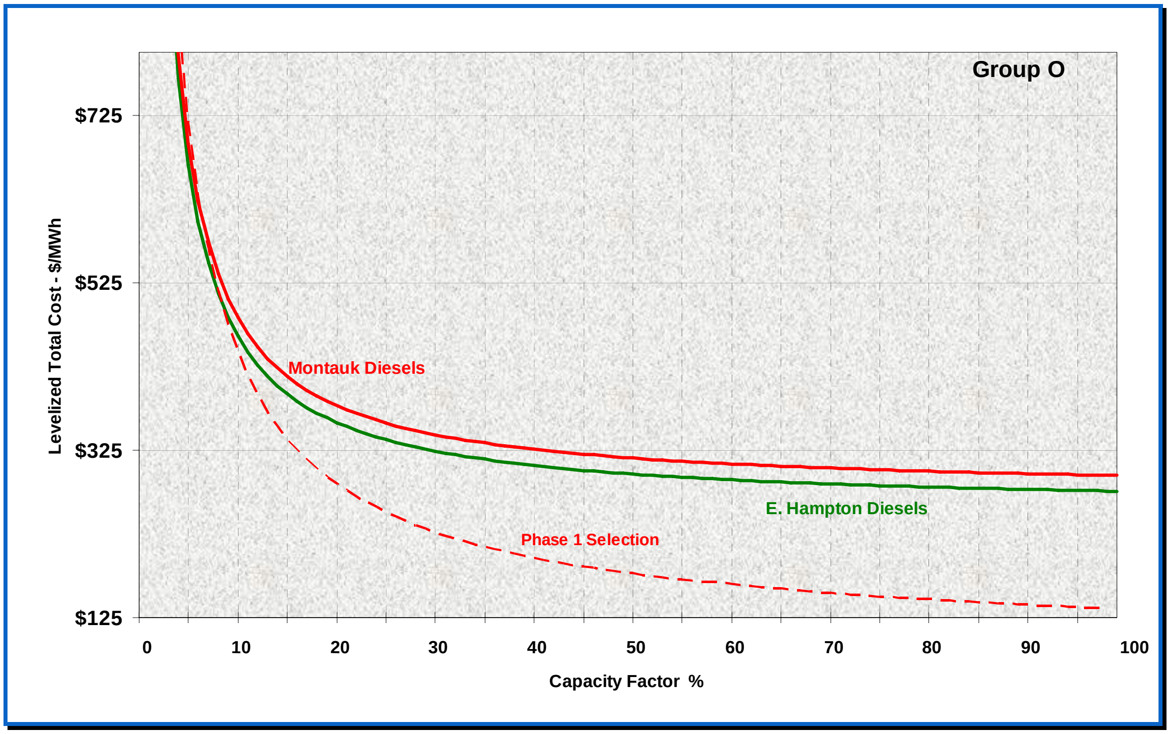
ICAP MW	Name	Levelized Cost				Environmental Emissions		
		Capacity $/kW-mo	Energy $/MWh	Capacity Factor	Total $/MWh	CO2 lb/MWh	NOx lb/MWh	SO2 lb/MWh
9	Southampton CT	$16.08	$527.61	1%	$2,728.93	3598	12.8457	6.2499
14	Southold CT	$16.08	$512.03	1%	$2,713.36	3493	12.1820	6.0673
15	Northport CT	$16.08	$600.25	1%	$2,801.57	4095	14.2843	7.1144
15	Port Jefferson CTs	$16.08	$458.75	1%	$2,660.07	3128	10.9113	5.4344
21	E. Hampton CT	$16.08	$331.81	1%	$2,533.13	2246	11.6458	3.9013
55	West Babylon 4	$16.08	$332.50	1%	$2,533.83	2268	7.3080	3.9396

76	Shoreham CTs	$ 8.46	$343.39	1%	$1,500.97	2343	8.5915	4.2555
132	Glenwood CTs	$16.08	$331.35	1%	$2,532.67	2256	8.1601	3.9185

8.7.5 Group O

Exhibit 8-21, Group O compares the cost of existing diesel peaking resources on Long Island to the cost of the Phase 1 Selection resources. These resources are cost effective for capacity factors below 5%. These units provide an essential reliability service for the eastern end of Long Island. However, the East Hampton and Montauk diesels have the highest NO_X emission rates of the Long Island generation fleet.

Exhibit 8-21 Existing Resource Located On Long Island – Group O

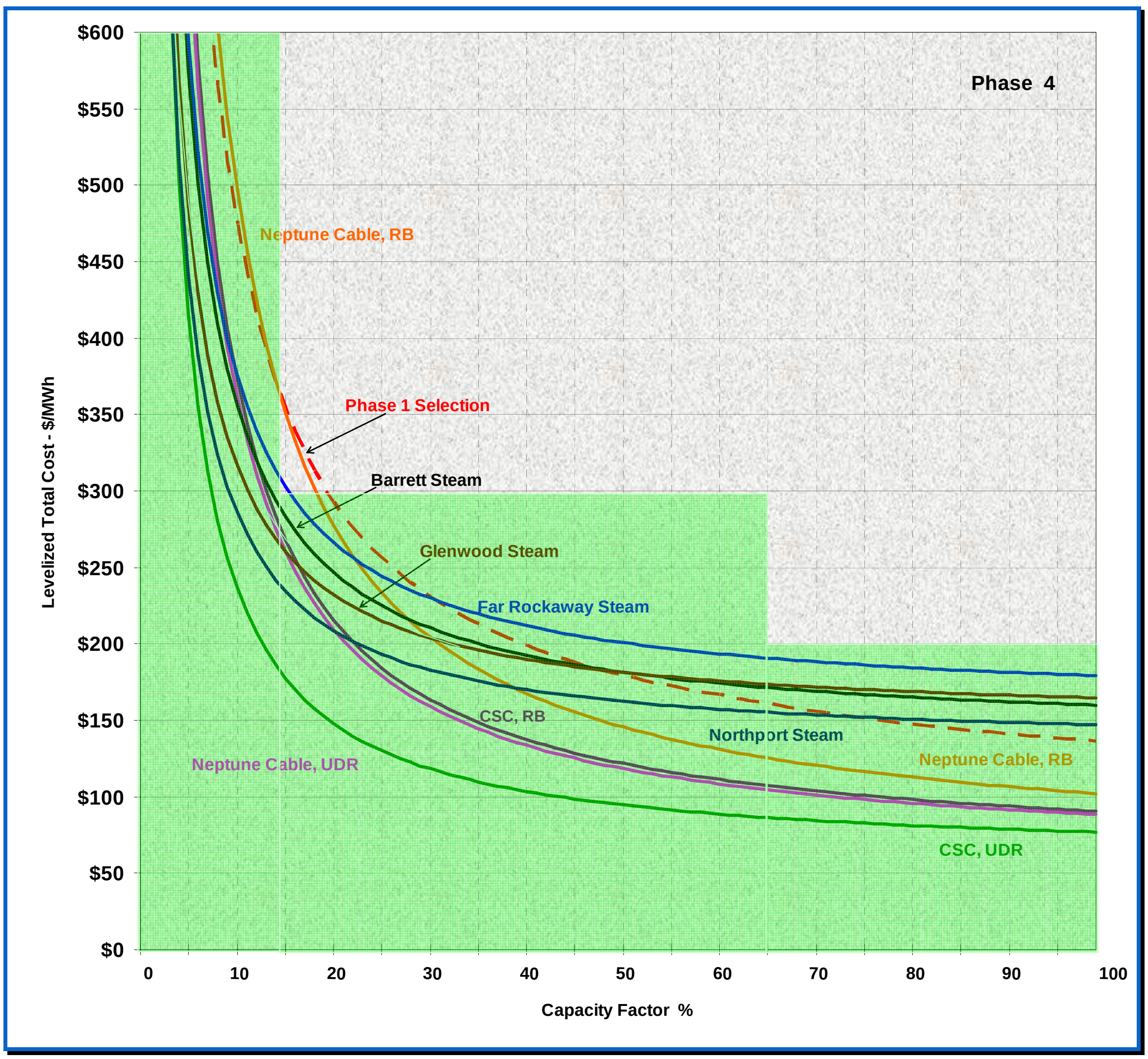


ICAP MW	Name	Levelized Cost				Environmental Emissions		
		Capacity $/kW-mo	Energy $/MWh	Capacity Factor	Total $/MWh	CO2 lb/MWh	NOx lb/MWh	SO2 lb/MWh
6	E. Hampton IC	$15.00	$255.24	1%	$2,308.83	1762	39.7902	3.0616
6	Montauk IC	$15.26	$273.68	1%	$2,363.30	1896	41.3440	3.2932

8.7.6 Phase 4 Summary

Exhibit 8-22 summarizes the results for this phase of the screening analysis by comparing the levelized cost of existing resources against each other and the Phase 1 selection. Not unexpectedly, the newest resources are cost effective against the Phase 1 technologies at higher capacity factors the older units in the Long Island fleet. Both Cross-Sound and Neptune Cables are low cost resources in comparison to other supply options available to LIPA. Caithness is a low cost resource comparable to new state-of-the-art alternatives. At lower capacity factors the existing older units are more cost effective than the Phase 1 selection units. Some exceptions are the smaller older combustion turbine units at Northport, Southold and Southampton. However, operational consideration may require continued use of these units to maintain reliability.

Exhibit 8-22 Existing Resource Located On Long Island – Phase 4



8.8 Phase 5 – Repowering Existing Resource Located On-Island

Phase 5 of the screening analysis addresses the potential for repowering existing fossil-fired steam resources located on Long Island.

Repowering refers to the process of upgrading existing generation turbines located on existing plant sites with new state-of-the-art, cleaner and more efficient generation equipment. Repowering alternatives fall into two major categories:

- "Conventional or Hybrid Repowering" which involves the re-utilization of existing steam turbine facilities using new or existing condensers, and
- "Backyard or Site Repowering" which involves the building of a standalone new combined cycle capacity on the site with a new steam turbine generator. In this case certain supporting site facilities are typically considered for re-use in the design.

Often, repowering requires temporarily shutting down the facility while the improvements are made. Depending on the circumstances this shutdown may result in adverse reliability impacts or a period of increased costs during the shutdown. In the vast majority of cases, the new technology installed is a gas-fired combined cycle power plant which results in more electricity being generated in a more efficient and environmentally friendlier manner. Repowering is advantageous for other reasons as well. Land use is less of an issue because existing sites are reused which reduces the need for siting new generation facilities. Electric delivery and fuel supply infrastructure are also already in-place at the existing site. Finally, the environmental benefits can be significant because older technologies are replaced with cleaner power solutions. It should be noted, however, that increasing the plant capacity and/or converting from one fuel source to another may require the addition of costly infrastructure improvements, such as upgrades to the electrical transmission system and/or the installation of new fuel delivery capability. While a repowered plant typically is a combined cycle plant, conventional or hybrid repowered plants are often less efficient and more expensive on a $/kW basis than new combined cycle plants. Re-using the older plant components in combination with the newer components often results in a less than optimum design. The economics of repowering versus building new on a greenfield site must be carefully analyzed. LIPA is investigating the repowering of older power plants on Long Island to produce more electricity with fewer emissions from the same amounts of fuel.

The intent here is to compare repowering existing resources to the Phase 1 Selection alternatives in order to identify resources that may be potential targets for repowering. The analysis is focused on determining whether it is more cost efficient to repower these units or to allow their continued operation as currently configured. The following table lists the technologies and the associated groupings in Phase 5.

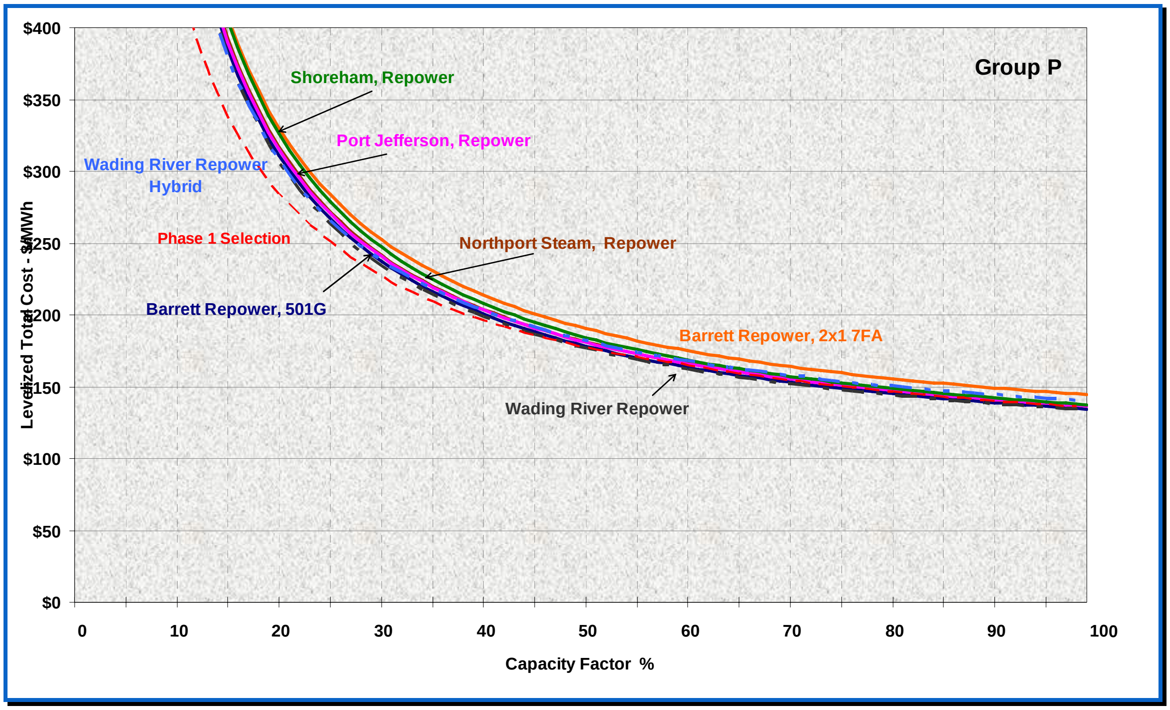
Group P

Wading River	- Conventional and Backyard repowering with 501G technology
Barrett	- Backyard repowering with 501G technology in a 1x1 configuration
	- Backyard repowering with 7FA technology in a 2x1 configuration
Port Jefferson	- Backyard repowering with 7FB technology in a 1x1 configuration
Shoreham	- Backyard repowering with 501G technology
Northport	- Backyard repowering with 7FB technology in a 3x1 configuration

8.8.1 Group P

Exhibit 8-23 shows the overall economics and emissions profile of the repowered alternatives studied. Since all of these options involve building new gas fired combined cycle units, the results of all options are very similar. The differences are very small and final determination of resource needs to be done in a more detailed simulation analysis. Several general conclusions can be reached from this screening analysis. 501G turbine technology is more cost effective and produces lower emissions than F-based technologies. The hybrid repowering of Wading River is more expensive, less efficient, and operates at a lower capacity factor than other options.

Exhibit 8-23 Repowered Resource Located On Long Island – Group P



ICAP MW	Name	Levelized Cost				Environmental Emissions		
		Capacity $/kW-mo	Energy $/MWh	Capacity Factor	Total $/MWh	CO2 lb/MWh	NOx lb/MWh	SO2 lb/MWh
127	Wading River Repower 501G	$91.69	$89.73	82%	$143.03	828	0.0575	0.0042
139	Wading River Repower - Hybrid	$83.78	$97.47	65%	$162.18	861	0.0801	0.0052
172	Barrett Repower, 1x1 501G	$69.27	$89.73	82%	$143.66	828	0.0575	0.0042
246	Port Jefferson, Repower 1x1 7FB	$32.72	$91.31	81%	$146.34	883	0.0557	0.0130

285	Barrett Repower, 2x1 7FA	$57.33	$97.51	78%	$157.31	862	0.0834	0.0051
303	Shoreham, Repower 501G	$41.81	$89.73	82%	$147.26	828	0.0575	0.0042
743	Northport Steam, Repower 3x1 7FB	$33.07	$90.66	82%	$145.97	877	0.0550	0.1284

8.9 Technology Short List

Based on the above screening analysis and policy guidance, a shortlist of technologies was selected for the alternative plan analysis in Section 9. The guiding principal for selection was whether the technology was among the best performing in its group or phase, was under active consideration as an alternative or was under consideration for policy decisions. Exhibit 8-24 shows the selected technologies.

Exhibit 8-24 Short List of Technologies Used in Alternative Plans

Supply Options	Transmission Options
Generic On-Island Combined–Cycle	Loss Reduction
Mobile Generating Units	NUSCO Upgrade 1 and 2 (Combined)
Fuel Cell Stack	Neptune Cable (UDR)
Generic Off-Island Nuclear	PJM Cable II (UDR)
Efficiency Options	**Renewable Options**
Clean Energy Initiative	Off-Shore Wind
ELI Base Program	Off-Island Renewables
ELI Advanced & Accelerated Program	Photovoltaic Roof
Intelligent Metering	Solar Pioneer
Repowering Options	**Retirement Options**
Barrett Repowering	Barrett Retirement
Northport Repowering	Northport Retirement
Port Jefferson Repowering	Port Jefferson Retirement
	Far Rockaway Retirement
	Glenwood Retirement

9 Development of the Electric Resource Plan

The Draft Electric Resource Plan presented a comparison of two electric resource plans - the Reference Plan and the Representative Plan. This section describes the process LIPA used to evaluate alternative plans, and presents the analysis and rationale that LIPA used to develop the Representative Plan. To make it easier to understand the results of the analysis, each alternative plan that was evaluated was grouped with other plans to form "analysis groups". Section 9.1 provides an essential guide to what was evaluated, including a key in section 9.1.4, which lists the alternative plans considered, the groups they belong to, and the section numbers where additional information and analysis can be found.

9.1 Alternative Plan Analysis

Section 8 of this appendix describes a screening analysis of a broad range of technology options. While a screening analysis determines the relative ranking of different types of technologies, it is not an effective tool for determining the best resource plan. The screening analysis does not capture the effect of the power system on the performance of the technology, nor does it pick up the effect of the technology on the power system. Important information like the effect on system-wide air emissions, impacts to customer bills and rates, and effects on system efficiency are not captured by a screening analysis. Detailed modeling of alternative plans picks up the system-wide effects by rigorously modeling the interaction of the plan resources with the existing power system. However, the detailed modeling of alternative plans is a complex, time consuming process that cannot be used to test every option. To develop the Draft Electric Resource Plan, the screening analysis was used to develop a short list of the most economic alternatives among each type, or group, of technologies. This short list of technologies is then tested in the context of the electric system using detailed modeling of alternative plans.

Detailed computer simulation models are used to capture the costs and benefits of alternative plans. These are the same models that are used to evaluate proposals from power suppliers, evaluate environmental compliance strategies, guide LIPA's participation in the power markets, as well as develop and monitor budgets. This analysis incorporates input following separate models:

- **Capacity Market Model** – Models the need for new resources, determines the timing of new resources and projects the prices in the capacity markets.
- **Production Simulation Model** – Models the detailed operation of the NYISO, ISO-NE and PJM Interconnection power systems including transmission constraints, individual plant operation, Location Based Marginal Pricing (LBMP) and Transmission Congestion Contracts (TCC). Data from this model is used to extract detailed information related to LIPA's transactions in the ISO markets and the fuel consumptions and air emissions of each generating unit.
- **Power Purchase Contract Model** – Simulates the finances of Independent Power Producers to project the price that LIPA might be charged for a contract for a specific type of generating unit.
- **Financial Model** – Integrates the financial data from the above models to determine the projected integrated impacts on revenue requirements, average rates and average customer bills.

While these models can be effective for short term decisions like budgeting and market participation where most of the conditions are relatively well known, using these models for long term planning needs to be done with caution. Since many of the input variables are based on forecasts and projections that may or may not materialize, the results of the analysis are not likely to be accurate forecasts. The results should be used to gauge the relative merits of various alternative plans and should be tempered with judgment to help guide the development of a resource plan.

This report is targeted at identifying the actions that LIPA should take in the 2009 to 2018 period. However, some power supply options like energy efficiency programs and new power plants, can take as long as a decade to contract, license, implement, and build. Furthermore, some types of electric resources take several years before they begin to save the customer money. As a result, the resource planning analysis is conducted over a longer period, from 2009 to 2028, to allow for identification of the actions that need to be taken, and to allow for evaluation of the impacts of those actions made in the 2009 to 2018 time period.

9.1.1 Evaluation Metrics

In order to assess the benefits of each alternative planning option, LIPA has established a list of metrics or criteria that are important for designing a successful electric plan. Exhibit 9-1 provides a summary of the evaluation metrics considered. LIPA uses four major categories of evaluation metrics: economic, production efficiency, reliability implications, and environmental measures. These are described in this section and each is used to demonstrate the relative benefits of the options considered.

Exhibit 9-1 Evaluation Metrics

Economic
Net Present Value (NPV) total revenue requirements in 2009 dollars
Annual revenue requirements
Annual average electric rates
Production Efficiency
Average heat rate of LIPA contracted resources
Reliability Metrics
Surplus or deficit compared to probability weighted NYSRC Total Statewide Requirements for LIPA
Surplus or deficit compared to probability weighted NYISO Locational Requirement for Long Island
Environmental Metrics
Projected SO_2 allowances compared to SO_2 emissions from LIPA contracted units
Projected NO_X allowances compared to NO_X emissions from LIPA contracted units
Energy weighted share of statewide CO_2 RGGI emissions allowances compared to CO_2 emissions from LIPA contracted units
Total LIPA footprint of CO_2 emissions from LIPA contracted units plus market purchases of energy at ISO/RTO incremental emissions per MWh
Assess alternative plans on $/ton carbon reduced or increased from the Reference Plan

Economic Metrics

The economic factors evaluated are net present value of total revenue requirements in 2009 dollars, annual revenue requirements, and annual average electric rates.

- The net present value (NPV) of the total revenue requirements metric incorporates annual revenue requirements over the entire planning period and renders them comparable across plans by taking the net present value of each plan's stream of revenues. The NPV, or discounted value, is used to eliminate the effects of the time value of money and better reflect the value of a course of action in "today's" dollars.
- Annual Revenue Requirements are the total amount of annual revenue that LIPA must recover from customers' billings in order to cover its costs of operation, which includes both operating and capital costs.
- An annual average electric rate provides the unit cost that will be borne by customers and is simply calculated as the cost per kWh.

Production Efficiency Metrics

Production efficiency is evaluated using a comparison of the average heat rate between options. This allows LIPA to compare the efficiency of alternative opportunities while meeting the electricity needs of its customers.

Reliability Metrics

Reliability implications are evaluated through an assessment of resource adequacy using criteria established by NYSRC, NYISO and LIPA, each of which ensures that required reliable resources are in place to serve customer peak demand for electricity. LIPA plans to meet the requirement that is most restrictive, or that which requires the earliest and largest level of resource additions given the current and projected circumstances[1]. In the development of this Draft Electric Resource Plan, the following criteria were found to be most binding.

- **NYSRC Total Statewide Reserve Margin Requirements for LIPA** – This criteria which is followed by all load serving companies within the state, is used to assure that there is adequate power supply to meet the customer's demand for energy at the time of the NYISO system peak load.
- **NYISO Zone K Locational Requirements for Long Island** – Due to constraints of the New York State transmission system, only a portion of Long Island's electricity needs can be imported to Long Island. The remaining energy must be produced on Long Island. This criteria assures that the combined transmission import capability combined with Long Island generating capacity provide adequate power supply to meet the customer's demand for electricity at the time of the Long Island system peak.

Environmental Metrics

Environmental metrics address emissions by comparing the plans' emissions of SO_2, NO_X, and CO_2 from LIPA contracted plants and the impact on LIPA's total carbon footprint from the CO_2 emissions of all of LIPA's contracted plants.

[1] In the 2004-2013 Energy Plan, a LIPA criterion called OPCAP-C was the most binding planning criteria. In this plan the NYISO criteria was the most binding planning criteria. For simplicity LIPA is presenting only the NYSRC and NYISO criteria. LIPA will continue to monitor the OCAP-C criteria and, if it becomes more binding in the future, may use it to determine need for resources.

9.1.2 Reference Plan Description

The Reference Plan is a hypothetical plan that establishes a benchmark for comparison against other plans. These alternative plans are developed to evaluate differing approaches to meeting the projected resource need. In order to compare the various alternative plans, LIPA develops a Reference Plan against which other plans can be benchmarked, referred to in these documents as the "Reference Plan". This Reference Plan does not represent LIPA's preferred plan, but is simply a means to measure the relative attractiveness of the alternative plans. Alternative plans are developed to test various strategies such as:

- Relying upon specific types of resources such as energy efficiency, repowering, or renewables;
- Achieving certain objectives such as reducing CO_2 emissions, minimizing rate impacts or reducing the impacts of fuel price volatility; or
- Combining strategies based on the information gained from evaluating other strategies.

The Reference Plan provides a benchmark that alternative plans may be compared to on a differential basis to determine the relative attractiveness of a given approach. It does not in any way represent LIPA's preferred Electric Resource Plan. The Reference Plan assumes that:

- The existing Clean Energy Initiative is allowed to lapse at the end of 2008;
- No new energy efficiency initiatives are implemented;
- No new resources are procured for LIPA's RPS Program; and
- Any additional need for resources is met exclusively with Long Island-based gas-fired combustion turbine technology in a combined cycle configuration.

The Reference Plan and all the alternative plans, unless specific differences are noted, contain many common assumptions including:

- Underlying escalation rates
- Fuel price forecasts
- Load growth forecasts (before the effects of energy efficiency programs)
- Forecasted emission credit costs
- If an existing contract with LIPA expires, the resource remains in operation without the contract.
- The existing portfolio of resources remains in operation through the end of the planning period.
- The Trustee approved Marcus Hook Contract, Brookfield Energy Hydro Contract and PPL Landfill Gas Contract begin deliveries as scheduled.

Exhibit 9-2 summarizes the major components of the Reference Plan that differentiate it from other plans. This type of table is used to present summaries of the various alternative plans in each of the group analysis sections. This exhibit shows that the Reference Plan has no additional energy efficiency, no RPS or other renewable additions, adds eight new 367 MW (Summer Rating) 501-G generating units over the study period starting with the first unit in 2014. Additionally it repowers and retires no units and does not improve interconnections.

Exhibit 9-2 Summary of Plans – Reference Plan

ID	Plan Name	Energy Efficiency	Renewables				Upgrade Fleet			Inter-connection
			RPS	Wind	Fuel Cell	Solar	New	Repower	Retire	
A	Reference Plan	None	None	None	None	None	8 501G Starting in 2014	None	None	None

9.1.3 Reference Plan Results

The results for each analysis group are presented in a standardized dashboard format. Exhibit 9-3 displays the dashboard results for the Reference Plan. The dashboard displays the following information.

Plan – Short description of the plan under study, including its letter identification for quick reference.

New Generation – This metric depicts the total megawatts of new generating capacity added over the study period.

Capacity Criteria - The reliability metric measure of the number of years in which alternative resource plans are projected to meet or exceed the projected New York ISO Long Island Locational Capacity Criteria for reliability. This metric is shaded to indicate the number of years in compliance. Green is for 20 years at or above compliance, yellow is for more than 10, but less than 20 years at or above compliance, and finally red is for fewer than 10 years at or above compliance targets. The same type of color coding scheme is used for environmental emissions.

Cumulative Annual Revenue Requirements - Revenue requirements are the total amount of annual revenue that LIPA must recover from customer billings in order to cover its costs of operation, which includes both operating and capital costs over the study period.

Cumulative Annual Revenue Requirements on a Net Present Value (NPV) basis – This metric allows comparisons of the projected NPV of the annual revenue requirements. The NPV, or discounted value, is used in this metric to eliminate the effects of the time value of money, and to better reflect the value of a course of action in today's dollars. The NPV rate is 5.643%.

Average Annual Revenue Rate (cents/kWh) - This metric provides the ability to assess the potential impact on average customer rates. Annual average electric rates are calculated by dividing projected annual revenue requirements by projected total sales of electricity.

Sales of Electricity in 2018 and 2028 (TWh) – Total LIPA sales of electricity measured in terms of Terawatt-hours (millions of Megawatt-hours) for both the short (2018) and long-term (2028).

Average Long Island System Heat Rate in 2018 and 2028 (BTU/kWh) - The average system heat rate measures how much energy is required to produce a kWh of electricity. A lower system heat rate indicates a more efficient system. Heat rate is defined as the ratio of fuel burned to electricity produced and is typically described in units of Btu/kWh. Results are presented for both 2018 and 2028 in order to gauge both the short and long-term implications.

SO_2 Emissions Target - This metric measures the number of years that sulfur dioxide (SO_2) emissions from LIPA contracted units are below target levels. Planning targets are based on existing and/or best estimates of projected regulations for SO_2. This metric is shaded in the same manner as the capacity criteria above, to indicate the number of years below target

NO_X Emissions Target - This metric measures the number of years that nitrogen oxides (NO_X) emissions from LIPA contracted units are below target levels. Planning targets are based on existing and/or best estimates of projected regulations for NO_X. This metric is shaded in the same manner as the capacity criteria above, to indicate the number of years below target

CO_2 Compliance Emissions Target – This metric measures the number of years that carbon dioxide (CO_2) emissions from LIPA contracted units are below target levels. Planning targets are based on existing and/or best estimates of projected regulations for CO_2. This metric is shaded in the same manner as the capacity criteria above, to indicate the number of years below target

CO_2 Footprint Emissions Target - This metric measures the carbon dioxide (CO_2) footprint emissions covering both LIPA contracted units and market purchases of energy from neighboring systems. This metric measures the number of years that CO_2 footprint emissions are below target levels. This metric is shaded in the same manner as the capacity criteria above, to indicate the number of years below target

CO_2 Cumulative Compliance Emissions - This metric addresses the total number of tons of CO_2 emitted in total over the study period from LIPA contracted units.

CO_2 Cumulative Footprint Emissions - This metric addresses the total number of tons of CO_2 emitted in total over the study period from LIPA contracted units and market purchases of energy from neighboring systems.

CO_2 Net Cost or Savings for Footprint Emissions ($/Ton) - Depicts the cost of reducing CO_2 emissions. This metric is calculated by dividing the cost difference between the Reference Plan and an Alternate Plan by the change in CO_2 emissions between the two plans. A positive number indicates how much consumers are paying per ton of CO_2 emission reduced while a negative number indicates how much consumers are saving per ton of CO_2 emission reduced.

Exhibit 9-3 Dashboard Results – Reference Plan

	Reliability		Cost			Case (2018 / 2028)				Emissions Target Years Met				CO_2 Emissions		
Plans	New Generation (MW)	Capacity Criteria	Cum. Annual Rev. Req. ($Bil)	Cum. Annual Rev. Req., NPV	Avg. of Ann. Rev Rate (Cents/kW)	2018 Sales of Electricity (TWh)	2028 Sales of Electricity (TWh)	Avg. LI Sys Heat Rate, 2018 (BTU/kWh)	Avg. LI Sys Heat Rate, 2028 (BTU/kWh)	SO_2	NO_X	CO_2 Compliance	CO_2 Footprint	Cum. Compliance (mTons)	Cum Footprint (mTons)	Net Cost (Savings) per Footprint Reduction ($/ton)*
A) Reference Plan	3,191	20	115.7	66.9	22.7	24.7	30.5	9,013	8,099	20	20	6	0	191	295	-

9.1.4 Summary of Analysis Groups

Exhibit 9-4 provides a guide to the analysis that is presented in the remainder of this section of this appendix. Each plan that is used in the analysis is shown on an individual row. An "X" indicates which analysis group each plan is used in. While some plans are used in just one group, other plans are used in multiple groups. Each section includes a more detailed description of each group, as well as the results of the analysis and the findings and conclusions associated with those results for each group of plans.

Exhibit 9-4 Summary of Analysis Groups

Letter	Name	Scenario Group Analysis										
		9.2 Renewable Portfolio Analysis	9.3 Energy Efficiency Options	9.4.1 Repowering Options	9.4.2 Barrett Repowering Technology Alternatives	9.4.3 Repowering Finance Alternatives	9.4.4 Port Jefferson Repowering Technology Alternatives	9.4.5 Northport Repowering Technology Alternatives	9.5 Retirement Options	9.6 Efficiency/Repowering Combinations	9.7.1 Alternative Strategies Phase I	9.7.2 Alternative Strategies Phase II
A	Reference Plan	X									X	X
B	Reference Plan 25% RPS	X	X									
C	Reference Plan 30% RPS	X										
D	Continue CEI		X								X	
E	ELI		X	X					X	X		
F	15 x 15		X							X	X	X
G	ELI + Repower Barrett 1 with 2x1 7FA			X		X						
H	Port Jefferson 3 Repowering 7FB ACC			X			X					
I	Northport 1 Repowering 3x1 7FB ACC			X				X				
J	ELI + Repower Barrett 1 with 501G ACC				X	X				X		
K	ELI + Repower Barrett 1 & 2 with 2x1 7FA				X	X						
L	ELI + Tax Exempt Repower Barrett 1 with 501G					X						
M	ELI + Tax Exempt Repower Barrett 1 with 2x1 7FA					X						
N	ELI + Tax Exempt Repower Barrett 1 & 2 with 2x1 7FA					X						
O	Port Jefferson 3 Repowering 501G OTC						X					
P	Northport 4 Repowering 2x1 501G OTC							X				
Q	Northport 1&2 Repowering 3x1 7FB ACC							X				
R	Northport 3&4 Repowering 2x1 501G OTC							X				
S	Retire Barrett 1								X			
T	Retire Far Rockaway								X			
U	Retire Glenwood 4&5								X			
V	Retire Glenwood 4&5 and Far Rockaway								X			
W	15x15 + Repower Barrett 1 with 2X1 7FA									X		
X	CEI + Repowering Focus										X	
Y	Low Operating Cost Focus										X	
Z	Environmental Focus										X	X
AA	Market Access Focus										X	
BB	15 x15 Repowering Plan											X
CC	15 x 15 Retirement Plan											X
DD	Representative Plan											X
EE	Representative Plan with Oil Ban											X

The analysis groups are as follows

- **Renewable Portfolio Standard Group** – This group evaluates the impact of using different Renewable Portfolio Standard Targets
- **Energy Efficiency Group** – This group evaluates the impact of using different levels of energy efficiency
- **Repowering Groups** – This consists of 5 groups of alternative plans that study the performance of repowering, repowering financing options, and technology options at the major sites.
- **Retirement Options** – This examines the performance of plans that involve retiring power plants at various sites.
- **Efficiency/Repowering Combination**s – Examines the interaction of repowering and energy efficiency.
- **Alternative Strategies** – The above groups mostly focused on a single strategy like renewables, energy efficiency or repowering. The two Alternative Strategy groups examine how different strategies, including those that combine options from multiple groups compare with each other. Phase I group were performed first and then knowledge gained from the Phase I group was used to create the Phase II group.

9.2 Renewable Portfolio Standard Group

This group is used to assess the projected performance of Renewable Portfolio Standards (RPS). The NYS Public Service Commission implemented a standard of achieving 25% renewable energy statewide by 2013[2]. Although LIPA is not regulated by the PSC and thus not obligated to participate in the PSC RPS program, LIPA has decided to voluntarily implement its own program to do its share in meeting the statewide target. Unlike the PSC RPS program, which is implemented for investor owned utilities by NYSERDA; LIPA is implementing its own program. There are two major differences between the programs:

- NYSERDA's program purchases only renewable energy credits (RECs). LIPA's program purchases both RECs and renewable energy.
- NYSERDA's program requires the energy be delivered to New York State. LIPA's program requires delivery to Long Island.

As part of his 45 x 15 program, Governor Patterson has asked the Public Service Commission to consider implementing a RPS standard of 30% renewables statewide by 2015.

Description of Alternative RPS Plans

Exhibit 9-5 shows the three alternative plans used to investigate the impacts of different levels of RPS programs. The scenarios are identical to the Reference Plan except that they have different levels of RPS programs. All three scenarios assume no energy efficiency programs, no repowering or retirement of

[2] This program took credit for the renewable resources that existed in New York State in 2003. Since these resources already provided about 17% of the State's energy, an additional amount of about 8% was needed by 2013. The program assumed 1% would come from Green Choice programs and the remaining 7% from the RPS program. After 2013, additional load growth would be supplied by 25% renewable energy.

existing units and no additional interconnections. Since the RPS program purchases RECs as well as renewable energy but not capacity, the expansion plans for all scenarios are identical. The three plans are:

- **The Reference Plan –** described in detail in Section 9.1.2 above. This plan assumes that the current and Trustee approved contracts for Energy and RECs continue, but that no additional contracts for RPS are added.
- **The Reference Plan 25% RPS** – assumes that LIPA continues to implement the program to achieve its share of the additional energy required by 2013 to provide for its share of the 25% statewide goal and provides 25% of its load growth from renewable energy.
- **The Reference Plan 30% RPS** – assumes that the RPS program would be expanded to have LIPA contribute its share toward achieving the 30% statewide goal by 2015 and would provide 30% of its load growth from renewable energy thereafter.

In both RPS Plans the RPS power is assumed to be produced off Long Island and imported to Long Island over its interties. This power is assumed to be procured at a premium over the cost of regular energy. This representation is similar to LIPA's current RPS contracts. When LIPA implements its RPS Plan, LIPA is likely to use a mix of off-Island resources, on-Island resources like PV projects, or ocean-based resources connected directly to Long Island.

Exhibit 9-5 Summary of Plans – RPS Group

ID	Plan Name	Energy Efficiency	Renewables				Upgrade Fleet			Inter-connection
			RPS	Wind	Fuel Cell	Solar	New	Repower	Retire	
A	Reference Plan	None	None	None	None	None	8 501G Starting in 2014	None	None	None
B	Reference Plan 25% RPS	None	25% x 2013	None	None	None	8 501G Starting in 2014	None	None	None
C	Reference Plan 30% RPS	None	30% x 2015	None	None	None	8 501G Starting in 2014	None	None	None

Results of Alternative RPS Plans

Exhibit 9-6 displays the dashboard results for the three alternative plans. The first line shows the absolute values for each metric of the Reference Plan. The second and third line shows the change between the Reference Plan and the alternative plans. These changes are calculated by subtracting the alternative plan from the Reference Plan. The compliance indicators (red, green or yellow boxes) are not subtracted since differences in these indicators are relatively easy to determine.

In evaluating these results, it is important to keep in mind that implementing energy efficiency programs will reduce the cost of RPS compliance by reducing load growth and thereby reducing the amount of renewable resource that will need to be procured.

In both RPS Plans, customer bills and rates are higher because of the cost of purchasing renewable energy to meet the RPS standards. The cumulative cost impact of implementing RPS over 20 years is projected to be $1.7 billion in the 25% RPS Plan and $2.4 billion in the 30% RPS Plan. The projected rate impacts average 0.3 cents per kWh and 0.5 cents per kWh respectively for the 25% RPS Plan and 30% RPS Plan. The projected cumulative CO_2 footprint RPS reductions are 30 million tons in the 25% RPS Plan and 42 million tons in the 30% RPS Plan. The average cost per ton of CO_2 reductions for both the 25% RPS Plan and 30% RPS Plan is $57/ton, which is higher than most CO_2 allowance cost projections. While the CO_2 emissions savings are significant, RPS programs alone are not sufficient to allow the CO_2 footprint target to be met in any year.

Exhibit 9-6 RPS Group – Results and Findings (2009-2028)

	Reliability		Cost			Plan (2018 / 2028)				Emissions Target Years Met				CO_2 Emissions		
Plan	New Generation (MW)	Capacity Criteria	Cum. Annual Rev. Req. ($Bil)	Cum. Annual Rev. Req., NPV	Avg. of Ann. Rev Rate (Cents/kW)	2018 Sales of Electricity (TWh)	2028 Sales of Electricity (TWh)	Avg. LI Sys Heat Rate, 2018 (BTU/kWh)	Avg. LI Sys Heat Rate, 2028 (BTU/kWh)	SO_2	NO_x	CO_2 Compliance	CO_2 Footprint	Cum. Compliance (mTons)	Cum Footprint (mTons)	Net Cost (Savings) per Footprint Reduction ($/ton)*
A) Reference Plan	3,191	20	115.7	66.9	22.7	24.7	30.5	9,013	8,099	20	18	6	0	191	295	-
B) Reference Plan 25% RPS	0	20	1.7	0.8	0.3	0.0	0.0	0	0	20	18	6	0	0	-30	57
C) Reference Plan 30% RPS	0	20	2.4	1.2	0.5	0.0	0.0	0	0	20	18	6	0	0	-42	57

Findings from Alternative RPS Plans Analysis

This evaluation of the Alternative RPS Plans reaches the following findings:

- This analysis shows the worst case impact of RPS on customer costs and the best case on CO_2 reduction potential. As is demonstrated in other Plan Groups, the costs of CO_2 reductions from RPS alone are higher than when RPS is combined with energy efficiency.
- Implementation of the 25% RPS is projected to increase average customer rates by an average of 0.3 cents or 1.3% over the study period and reduce CO_2 footprint tons by 30 million tons or 10.2%.
- Implementation of the 30% RPS is projected to increase average customer rates by an average of 0.5 cents or 2.2% over the study period and reduce CO_2 footprint tons by 42 million tons or 14.2%.
- The cost per ton of implementing RPS programs is higher than the CO_2 allowance cost per ton that is projected to result from proposed Climate Change Legislation.

9.3 Efficiency Options Group

This group is used to assess the projected performance of various energy efficiency programs. LIPA completed its 10 year Clean Energy Initiative at the end of 2008. In 2009, LIPA began implementation of the $926 million Efficiency Long Island program which targets over 500 MW of peak load reductions. Section 5 of the Draft Electric Resource Plan report describes the proposed ELI program in more detail. As part of the Governor's 45 x 15 program, energy efficiency savings from 2007 to 2015 have been targeted at 15% of what the projected load would have been without the program. A preliminary plan for addressing the 15% energy efficiency goal is contained in Section 5 of the Draft Electric Resource Plan report. The ELI program is one of the first steps that LIPA is taking to help achieve this goal.

Description of Efficiency Options Plans

Exhibit 9-7 shows the four alternative plans used to investigate the impacts of different levels of Energy Efficiency programs. All four of the plans assume that LIPA continues to pursue implementation of the current 25% RPS program. Since energy efficiency reduces the amount of renewable energy needed to meet the RPS targets, the benefits of energy efficiency will be even greater if LIPA implements a program to reach the 30% RPS goal. None of the plans have any specific wind, fuel cell or solar PV projects. They also do not have any repowering, retirements or additional interconnections. The four plans are:

- **Reference Plan 25% RPS** – This is the same as the second scenario in section 9.2 above. It assumes that no new energy efficiency programs are implemented after December 31, 2008. The effects of programs that were implemented prior to this date continue to provide their benefits. This plan requires the construction of eight new 501 G power plants over the 20 year study period.

- **Continue CEI** – This plan assumes that a program similar to the recently completed CEI program is implemented throughout the study period. The CEI program targets energy savings. It provides 174 MW of peak reduction and 714 MWh of energy savings by 2018 and 174 MW of peak reduction and 714 MWh of energy savings by 2028. The total cost of the program is $321 million through 2018 and $688 million through 2028. This plan requires the construction of seven new 501 G power plants over the 20 year study period, one less than in the Reference Plan 25% RPS.

- **ELI** – This plan assumes implementation of the currently approved ELI throughout the study period. The ELI program targets peak reductions in order to defer the construction of new power plants. It provides 508 MW of peak reduction and 1,663 MWh of energy savings by 2018 and 880 MW of peak reduction and 2,063 MWh of energy savings by 2028. The total cost of the program is $926 million through 2018 and $2,500 million through 2028. This plan requires the construction of five new 501 G power plants over the 20 year study period, three less than in the Reference Plan 25% RPS.

- **15 x 15** – This plan assumes that an aggressive energy efficiency program is implemented to achieve the Governor's 15 x 15 goal. This program, which targets energy savings includes, a broad array of energy savings measures discussed more fully at the end of Section 5 of the Electric Resource Plan. It provides 1,359 MW of peak reduction and 4,534 MWh of energy savings by 2018 and 1,886 MW of peak reduction and 5,704 MWh of energy savings by 2028. The total cost of the program is $2,448 million through 2018 and $6,229 million through 2028. Due to the much more aggressive efficiency efforts, this plan requires the construction of only two new 501 G power plants over the 20 year study period, six less than in the Reference Plan 25% RPS.

Exhibit 9-7 Summary of Plans – Efficiency Options

ID	Plan Name	Energy Efficiency	Renewables				Upgrade Fleet			Inter-connection
			RPS	Wind	Fuel Cell	Solar	New	Repower	Retire	
B	Reference Plan 25% RPS	None	25% x 2013	None	None	None	8 501G Starting in 2014	None	None	None
D	Continue CEI	CEI	25% x 2013	None	None	None	7 501G Starting in 2015	None	None	None
E	ELI	ELI	25% x 2013	None	None	None	5 501G Starting in 2016	None	None	None
F	15 x 15	15 x 15	25% x 2013	None	None	None	2 501G Starting in 2025	None	None	None

Results of Efficiency Options Plans

Exhibit 9-8 displays the dashboard results for the alternative efficiency option plans, which is a similar dashboard to the one previously displayed. The first line of Exhibit 9-8 differs in that it shows the absolute values for the Reference Plan 25% RPS instead of the Reference Plan. Similar to the previously discussed dashboard, the remaining lines show the change between the alternative plans and the Reference Plan 25% RPS.

In general, energy efficiency has the effect of deferring the need for new generation, decreasing the revenue requirements from customers (and thus reducing average customer bills), increasing the rates of customers, increasing the power production heat rate, and reducing the amount of CO_2 emissions. Since the CO_2 emissions decrease and costs decrease at the same time, customers, in effect, save money for each ton of emissions reduced.

Compared to the Reference Plan 25% RPS, the efficiency programs presented here result in reductions in both sales and annual revenue requirements. Customers consume fewer kWh and therefore average bills decrease. However, average electric rates increase. Compared to the Reference Plan 25% RPS, customers would save about \$2.1 billion under the CEI Plan, \$6 billion under the ELI Plan, and \$13.2 billion under the 15 x15 Plan.

Energy Efficiency results in deferral of the need for new capacity, resulting in an older, less efficient generating fleet. This results in the system on Long Island generating fewer megawatts, less efficiently. However, the overall fuel consumption required to meet customer demand decreases. The CEI Plan defers 367 MW of capacity, reduces sales by 0.7 TWh in 2018, and decreases Long Island generation efficiency by almost 0.9% in 2018. The ELI Plan defers 1,101 MW of capacity, reduces sales by 1.5 TWh in 2018, and decreases Long Island generation efficiency by almost 3.6% in 2018. The 15 x 15 Plan defers 2,202 MW of capacity, reduces sales by 4.0 TWh in 2018, and decreases Long Island generation efficiency by almost 8.7% in 2018

In each of the plans presented in Exhibit 9-8, Plan CO_2 emissions exceed LIPA's projected energy weighted share of statewide CO_2 RGGI emissions allowances in most years. The RGGI program is auction based, and has no planned "allocation" to meet its compliance target. LIPA would purchase additional credits in the RGGI auctions. Both the CEI Plan and ELI Plan reduce CO_2 from contractual plants. The 15 x 15 Plan reduce CO_2 emissions from contractual plants five times more than the ELI Plan.

LIPA's CO_2 footprint also shows much bigger reductions for the 15 x 15 Plan compared to the CEI and ELI Plans. All three efficiency plan show that consumers save money for each ton of CO_2 reduced. These programs offer the best performance of any single Plan studied.

Exhibit 9-8 Efficiency Options - Results and Findings (2009-2028)

Plan	Reliability		Cost			Plan (2018 / 2028)				Emissions Target Years Met				CO_2 Emissions		
	New Generation (MW)	Capacity Criteria	Cum. Annual Rev. Req. ($Bil)	Cum. Annual Rev. Req., NPV	Avg. of Ann. Rev Rate (Cents/kW)	2018 Sales of Electricity (TWh)	2028 Sales of Electricity (TWh)	Avg. LI Sys Heat Rate, 2018 (BTU/kWh)	Avg. LI Sys Heat Rate, 2028 (BTU/kWh)	SO_2	NO_x	CO_2 Compliance	CO_2 Footprint	Cum. Compliance (mTons)	Cum Footprint (mTons)	Net Cost (Savings) per Footprint Reduction ($/ton)*
B) Reference Plan 25% RPS	3,191	20	117.4	67.8	23.0	24.7	30.5	9,013	8,099	20	18	6	0	191	265	-
D) Continue CEI	-367	20	-2.1	-1.0	0.1	-0.7	-0.7	75	-30	20	16	6	0	-5	-4	-460
E) ELI	-1,101	20	-6.0	-2.8	0.1	-1.5	-1.9	294	171	20	16	7	0	-9	-6	-1,042
F) 15x15	-2,202	20	-13.2	-6.2	0.9	-4.0	-5.0	703	800	20	19	13	0	-47	-21	-631

Findings from Efficiency Options Analysis

This evaluation of the Efficiency Options reaches the following findings:

- The benefits of energy efficiency will be even greater if LIPA implements a program to reach the 30% RPS goal.
- Relative to the Reference Plan with 25% RPS, Energy Efficiency saves customers money and reduces average customer bills. However average rates increase.
- Taken in isolation, end use energy efficiency decreases Long Island Power production efficiency.
- Energy efficiency helps reduce the CO_2 emissions from LIPA contractual plants.
- Energy efficiency helps reduce LIPA's CO_2 footprint.

9.4 Power Plant Repowering Groups

Power plant repowering is one of the most extensively evaluated options in this Appendix because the results of the repowering studies contained in Appendix D-2c and D-2d were incorporated into the analysis. Because repowering is site-specific and technology-dependent, many options can be evaluated. All of the analysis presented in this subsection is based on LIPA's current policy of implementing the ELI program and the 25% RPS program. Changes in the RPS program are not anticipated to impact the results of the repowering decisions. Decisions on energy efficiency plans do interact with repowering decisions and are examined in Section 9.6. The following five repowering groups were examined:

- 9.4.1 – **Repowering Options** – Examines repowering at Barrett, Port Jefferson and Northport using the same technology.

- 9.4.2 – **Barrett Repowering Technology Alternatives** – Examines the use of alternative generating technologies and configurations at the Barrett site.
- 9.4.3 – **Repowering Finance Alternatives** – Examines the options of using tax exempt financing for various Barrett Repowering options.
- 9.4.4 – **Port Jefferson Repowering Technology Alternatives** – Examines the use of alternative generating technologies and configurations at the Port Jefferson site.
- 9.4.5 – **Northport Repowering Technology Alternatives** – Examines the use of alternative generating technologies and configurations at the Northport site.

The findings for all five of these repowering groups are summarized in Section 9.4.6.

9.4.1 Repowering Options Group

The Repowering Options Group is designed to assess repowering of Barrett, Port Jefferson and Northport using combined cycle units with air cooled condensers (ACC). It is assumed that completely new plants are built at the plant location and an existing unit or units are retired.

Description of Repowering Options Plans

Exhibit 9-9 shows four alternative plans used for the assessment of repowering at the various power plants. All four scenarios are identical in having the ELI efficiency program and 25% RPS program, but differ by having repowering occur at different power stations. Because the net change in power output at the stations varies from plan to plan, the timing of the expansion plan after the repowering may vary.

- **ELI** – This plan, identical to the ELI Plan in the Efficiency Options Group, contains no repowering. It establishes a benchmark for comparing other repowering alternatives. This plan requires the construction of five new 501 G power plants over the 20 year study period.
- **Repower Barrett 1 with 2x1 7FA ACC** – This plan is similar to the ELI plan with the addition of Barrett Unit 1 repowering, which repowers the existing steam unit with a gas fired 2x1 7FA combined cycle generator in 2016. The net output of the Barrett Station increases by 303 MW. This plan requires the construction of four new 501 G power plants over the 20 year study period.
- **Port Jefferson 3 Repowering 7FB ACC** – This plan is similar to the ELI plan with the addition of Port Jefferson 3 repowering, which repowers the existing steam unit with a gas fired 1x1 7FA combined cycle generator in 2016. The net output of the Port Jefferson Station increases by 149 MW. This plan requires the construction of five new 501 G power plants over the 20 year study period.
- **Northport 1 Repowering 3x1 7FB ACC** – This plan is similar to the ELI plan with the addition of Northport 1 repowering, which repowers the existing steam unit with a gas fired 3x1 7FA combined cycle generator in 2016. The net output of the Northport Station increases by 342 MW. This plan requires the construction of four new 501 G power plants over the 20 year study period.

Exhibit 9-9 Summary of Plans – Repowering Options

ID	Plan Name	Energy Efficiency	Renewables				Upgrade Fleet			Inter-connection
			RPS	Wind	Fuel Cell	Solar	New	Repower	Retire	
E	ELI	ELI	25% x 2013	None	None	None	5 501G Starting in 2016	None	None	None
G	ELI + Repower Barrett 1 with 2x1 7FA	ELI	25% x 2013	None	None	None	4 501G Starting in 2019	Barrett 1 2016	None	None
H	Port Jefferson 3 Repoweri ng 7FB ACC	ELI	25% x 2013	None	None	None	5 501G Starting in 2017	Port Jefferson 2016	None	None
I	Northport 1 Repoweri ng 3x1 7FB ACC	ELI	25% x 2013	None	None	None	4 501G Starting in 2020	Northport 2016	None	None

Results of Repowering Options Plans

In general, repowering to varying degrees has the effect of increasing the power output from the repowered stations deferring the need for new "greenfield" generation, increasing the revenue requirements from customers, increasing the rates of customers, improving the power production efficiency, and reducing the amount of CO_2 emissions.

Exhibit 9-10 displays the dashboard results for the Repowering Options plans. The first line of Exhibit 9-10 shows the absolute values for the ELI Plan. Similar to the previously discussed dashboard, the remaining lines show the change between the alternative plans and the ELI Plan.

Compared to the ELI Plan, the repowering programs presented here result in improved power production efficiency and reduced CO_2 emissions. However, both the total revenue required and the resulting electric rates increase in comparison the ELI Plan while sales remains the same. Compared to the ELI Plan, customers would incur additional costs totaling approximately $0.4 billion under the Barrett 1 Repowering Plan, $1.1 billion under the Port Jefferson 3 Repowering Plan, and $1.3 billion under the Northport 1 Repowering Plan.

Exhibit 9-10 Repowering Options – Results and Findings (2009-2028)

Plan	Reliability		Cost			Plan (2018 / 2028)				Emissions Target Years Met				CO_2 Emissions		
	New Generation (MW)	Capacity Criteria	Cum. Annual Rev. Req. ($Bil)	Cum. Annual Rev. Req., NPV	Avg. of Ann. Rev Rate (Cents/kW)	2018 Sales of Electricity (TWh)	2028 Sales of Electricity (TWh)	Avg. LI Sys Heat Rate, 2018 (BTU/kWh)	Avg. LI Sys Heat Rate, 2028 (BTU/kWh)	SO_2	NO_x	CO_2 Compliance	CO_2 Footprint	Cum. Compliance (mTons)	Cum Footprint (mTons)	Net Cost (Savings) per Footprint Reduction ($/ton)*
E) ELI	2,090	20	111.5	65.0	23.1	23.2	28.6	9,307	8,269	20	16	7	0	172	259	-
G) ELI + Repower Barrett 1 with 2x1 7FA ACC	131	20	0.4	0.2	0.1	0.0	0.0	-198	-176	20	20	7	0	-3.4	-11	41
H) Port Jefferson 3 Repowering 7FB ACC	237	20	1.1	0.6	0.2	0.0	0.0	-280	-71	20	20	7	0	0.3	-4	292
I) Northport 1 Repowering 3x1 7FB ACC	368	20	1.3	0.7	0.3	0.0	0.0	-499	-271	20	20	7	0	0.1	-8	178

9.4.2 Barrett Repowering Technology Alternatives Group

This Repowering Option Group examines what happens with different repowering configurations are employed at the Barrett site and the number of units retired is varied.

Description of Barrett Repowering Technology Alternatives Plans

Exhibit 9-11 shows three alternative plans used for the assessment of different repowering technologies at the Barrett power plant. All three scenarios are identical in having the ELI efficiency program and 25% RPS program, but differ by using different repowering technology configurations. Because the net change in power output at the stations varies from plan to plan, the timing of the expansion plan after the repowering may vary.

- **ELI + Repower Barrett 1 with 2x1 7FA - ACC** – This plan is the repowering technology used in Section 9.4.1. This plan Repowers Barrett 1 with a gas fired 2x1 7FA combined cycle generator in 2016. The net output of the Barrett Station increases by 303 MW. Like the 501G Plan below, this plan requires the construction of four new 501 G power plants over the 20 year study period, but the timing of the expansion plan varies.

- **Repower Barrett 1 with 501G ACC** –Barrett Unit 1 is repowered with a gas fired 501G combined cycle generator in 2016. The net output of the Barrett Station increases by 172 MW. This plan requires the construction of four new 501 G power plants over the 20 year study period

- **Repower Barrett 1 & 2 with 2x1 7FA** – This plan differs from the first plan in that it retires both the Barrett 1 and Barrett 2 units when the repowered unit comes on line. The same gas fired 2x1 7FA combined cycle generator is used in 2016. The net output of the Barrett Station increases by 115 MW. Because of the larger smaller net capacity gain, the ELI + Repower Barrett 1 &2 with 2x1 7FA scenario, requires the construction of five new 501 G power plants over the 20 year study period, one more than in the ELI + Repower Barrett with 501G Plan.

Exhibit 9-11 Summary of Plans – Barrett Repowering Technology Alternatives

I	Plan Name	Energy	Renewables	Upgrade Fleet	Inter-

D		Efficiency	RPS	Wind	Fuel Cell	Solar	New	Repower	Retire	connection
G	ELI + Repower Barrett 1 with 2x1 7FA	ELI	25% x 2013	None	None	None	4 501G Starting in 2019	Barrett 1 2016	None	None
J	ELI + Repower Barrett 1 with 501G ACC	ELI	25% x 2013	None	None	None	4 501G Starting in 2018	Barrett 1 2016	None	None
K	ELI + Repower Barrett 1 & 2 with 2x1 7FA	ELI	25% x 2013	None	None	None	5 501G Starting in 2018	Barrett1& 2 2016	None	None

Results of Barrett Repowering Technology Alternatives Plans

Exhibit 9-12 displays the dashboard results for the Barrett Repowering Technology Alternatives plans. The first line of Exhibit 9-12 shows the absolute values for the ELI + Repower Barrett 1 with 2x1 7FA - ACC plan the remaining lines show the change between the alternative plans and the ELI + Repower Barrett 1 with 2x1 7FA - ACC Plan.

Compared to the ELI + Repower Barrett 1 with 2x1 7FA - ACC Plan, the repowering technology alternatives presented here result in fairly consistent results with only minor variations. This is to be expected given the relative minor variations in design performance between the 501G and 7FA technologies.

The 2x1 7FA alternative has a $0.1 billion revenue requirement advantage over the study period and a small improvement in production efficiency by 2028. Repowering both Barrett 1 and 2 with 7FA technology provides additional generating capacity at an additional cost of $0.6 billion in revenue requirement over the study period which translates to a higher average annual rate requirement of 0.1 cents/kWh. Production efficiency is improved while the CO_2 footprint emissions are higher.

Exhibit 9-12 Barrett Repowering Technology Alternatives – Results and Findings (2009-2028)

Plan	Reliability		Cost			Plan (2018 / 2028)				Emissions Target Years Met				CO_2 Emissions		
	New Generation (MW)	Capacity Criteria	Cum. Annual Rev. Req. ($Bil)	Cum. Annual Rev. Req., NPV	Avg. of Ann. Rev Rate (Cents/kW)	2018 Sales of Electricity (TWh)	2028 Sales of Electricity (TWh)	Avg. LI Sys Heat Rate, 2018 (BTU/kWh)	Avg. LI Sys Heat Rate, 2028 (BTU/kWh)	SO_2	NO_x	CO_2 Compliance	CO_2 Footprint	Cum. Compliance (mTons)	Cum Footprint (mTons)	Net Cost (Savings) per Footprint Reduction ($/ton)*
G) ELI + Repower Barrett 1 with 2x1 7FA	2,221	20	111.9	65.2	23.2	23.2	28.6	9,109	8,093	20	20	7	0	169	248	-
J) ELI + Repower Barrett 1 with 501G ACC	-131	20	0.1	0.0	0.0	0.0	0.0	-146	25	20	19	7	0	1.0	6	-13
K) ELI + Repower Barrett 1 & 2 with 2x1 7FA	367	20	0.6	0.3	0.1	0.0	0.0	-286	-90	20	20	7	0	0.9	31	-18

9.4.3 Repowering Finance Alternatives Group

With the exception of this group, all of the repowering analysis has been done via a third party PPA contract with a taxable contractor. This group examines the effect of using tax exempt financing to build repowering projects.

Description of Repowering Finance Alternatives Plans

The same three plans as in Barrett Repowering Technology Alternatives are examined with and without tax exempt financing. The resulting six plans are as follows:

- **ELI + Repower Barrett 1 with 501G** – Barrett Unit 1 is repowered with a gas fired 501G combined cycle generator in 2016. The net output of the Barrett Station increases by 172 MW. This plan requires the construction of four new 501 G power plants over the 20 year study period
- **ELI + Tax Exempt Repower Barrett 1 with 501G** – This plan is identical to the ELI + Repower Barrett 1 with 501G Plan with the exception that is assumed to be financed with the use of tax exempt debt.
- **ELI + Repower Barrett 1 with 2x1 7FA** – Barrett Unit 1 is repowered with a gas fired 2x1 7FA combined cycle generator in 2016. The net output of the Barrett Station increases by 303 MW. Like the 501G Plan above, this plan requires the construction of four new 501 G power plants over the 20 year study period, but the timing of the expansion plan varies.
- **ELI + Tax Exempt Repower Barrett 1 with 2x1 7FA** – This plan is identical to the ELI + Repower Barrett 1 with 2x1 7FA Plan with the exception that is assumed to be financed with the use of tax exempt debt.
- **ELI + Repower Barrett 1 & 2 with 2x1 7FA** –Barrett 1 and Barrett 2 units are repowered with A gas fired 2x1 7FA combined cycle generator is used in 2016. The net output of the Barrett Station increases by 115 MW. This plan requires the construction of five new 501 G power plants over the 20 year study period.
- **ELI + Tax Exempt Repower Barrett 1 & 2 with 2x1 7FA** – This plan is identical to the Tax Exempt Repower Barrett 1 & 2 with 2x1 7FA Plan with the exception that is assumed to be financed with the use of tax exempt debt.

Exhibit 9-13 Summary of Plans – Repowering Finance Alternatives

ID	Plan Name	Energy Efficiency	Renewables				Upgrade Fleet			Inter-connection
			RPS	Wind	Fuel Cell	Solar	New	Repower	Retire	
J	ELI + Repower Barrett 1 with 501G ACC	ELI	25% x 2013	None	None	None	4 501G Starting in 2018	Barrett 1 2016	None	None
L	ELI + Tax Exempt Repower Barrett 1 with 501G	ELI	25% x 2013	None	None	None	5 501G Starting in 2016	Barrett 1 2016	None	None

G	ELI + Repower Barrett 1 with 2x1 7FA	ELI	25% x 2013	None	None	None	4 501G Starting in 2019	Barrett 1 2016	None	None
M	ELI + Tax Exempt Repower Barrett 1 with 2x1 7FA	ELI	25% x 2013	None	None	None	4 501G Starting in 2019	Barrett1&2 2016	None	None
K	ELI + Repower Barrett 1 & 2 with 2x1 7FA	ELI	25% x 2013	None	None	None	5 501G Starting in 2018	Barrett1&2 2016	None	None
N	ELI + Tax Exempt Repower Barrett 1 & 2 with 2x1 7FA	ELI	25% x 2013	None	None	None	5 501G Starting in 2018	Barrett1&2 2016	None	None

Results of Repowering Finance Alternatives Plans

Exhibit 9-14 displays the dashboard results for the Repowering Finance Alternatives plans. The first line of Exhibit 9-14 shows the absolute values for the ELI plus Repowering Barrett 1 with 501G Plan the second line show the change when tax exempt financing is utilized. The third and fourth lines provide a tax exempt comparison to the Repowering Barrett 1 with 7FA technology and the final two lines provide a tax exempt comparison to the Repowering Barrett 1&2 with 7FA technology.

Given this analysis is focused exclusively on the benefits of tax exempt financing there is no impact on system operations, capacity added or environmental emissions. Overall, tax exempt financing would reduce the cost and associated rate impact of all of these repowering alternatives.

Compared to the ELI plus Repowering Barrett with 501G Plan, tax exempt financing would provide a revenue requirement savings of $0.8 billion over the study period and an associated $0.2 cents/kWh reduction in average annual rates.

Compared to Repowering Barrett with 2x1 7FA technology, tax exempt financing would provide a revenue requirement savings of $1.1 billion over the study period and an associated $0.2 cents/kWh reduction in average annual rates.

Compared to Repowering both Barrett 1 and 2 with & 7FA technology, tax exempt financing would provide a revenue requirement savings of $1.2 billion over the study period and an associated $0.2 cents/kWh reduction in average annual rates.

In addition to demonstrating that tax exempt financing saves LIPA customers money, these plans indicate that tax exempt financing can make repowering more cost effective than expansion with traditionally financed 501G technology units. The ELI Plan without repowering had a cumulative revenue requirement of $111.5 billion. The repowering plans with tax exempt financing show cumulative revenue requirements of $111.2 billion, $110.8 billion and $111.3 billion respectively for the Barrett 1 2x1 7FA repowering, Barrett 1 501G repowering and the Barrett 1&2 2x1 7FA repowering.

Exhibit 9-14 Repowering Finance Alternatives – Results and Findings (2009-2028)

Plan	Reliability		Cost			Plan (2018 / 2028)				Emissions Target Years Met				CO_2 Emissions		
	New Generation (MW)	Capacity Criteria	Cum. Annual Rev. Req. ($Bil)	Cum. Annual Rev. Req., NPV	Avg. of Ann. Rev Rate (Cents/kW)	2018 Sales of Electricity (TWh)	2028 Sales of Electricity (TWh)	Avg. LI Sys Heat Rate, 2018 (BTU/kWh)	Avg. LI Sys Heat Rate, 2028 (BTU/kWh)	SO_2	NO_x	CO_2 Compliance	CO_2 Footprint	Cum. Compliance (mTons)	Cum Footprint (mTons)	Net Cost (Savings) per Footprint Reduction ($/ton)*
J) ELI + Repower Barrett 1 with 501G ACC	2,090	20	112.0	65.3	23.2	23.2	28.6	8,963	8,118	20	19	7	0	170	255	
L) ELI + Tax Exempt Repower Barrett 1 with 501G	0	20	-0.8	-0.4	-0.2	0.0	0.0	0	0	20	19	7	0	0.0	0	
G) ELI + Repower Barrett 1 with 2x1 7FA	2,221	20	111.9	65.2	23.2	23.2	28.6	9,109	8,093	20	20	7	0	169	248	-
M) ELI + Tax Exempt Repower Barrett 1 with 2x1 7FA	0	20	-1.1	-0.5	-0.2	0.0	0.0	0	0	20	20	7	0	0.0	0	-
K) ELI + Repower Barrett 1 & 2 with 2x1 7FA	2,588	20	112.5	65.5	23.3	23.2	28.6	8,823	8,003	20	20	7	0	170	279	-
N) ELI + Tax Exempt Repower Barrett 1 & 2 with 2x1 7FA	0	20	-1.2	-0.6	-0.2	0.0	0.0	0	0	20	20	7	0	0.0	0	-

9.4.4 Port Jefferson Repowering Technology Alternatives Group

The Repowering Option Group in Section 9.4.1 examined repowering using two repowering configurations along with two cooling technologies. This group examines what happens when the configurations and cooling technology used at the Port Jefferson site is varied.

Description of Port Jefferson Repowering Technology Alternatives Plans

Exhibit 9-15 shows two alternative plans used for the assessment of different repowering technologies at the Port Jefferson power plant. Both scenarios are identical in the fact that they incorporate the ELI efficiency program and 25% RPS program, but they differ by using different repowering and cooling technology configurations. Because the net change in power output at the stations varies from plan to plan, the timing of the expansion plan after the repowering may vary.

- **ELI + Port Jefferson 3 Repowering 7FB ACC** – This plan is the repowering technology used in Section 9.4.1. Port. Port Jefferson Unit 3 is retired in 2013 and the repowered unit, a gas fired 1x1 7FB ACC combined cycle generator comes online in 2016. The net output of the Port Jefferson Station increases by 44 MW. The configuration uses an Air-Cooled Condenser ("ACC") which cools the steam from the generator through the use of ambient air. ACC operate at a higher temperature than water cooled versions and save water at the expense of a reduction in efficiency. This plan requires the constructions of five new 501 G power plants over the 20 year study period**.**
- **Port Jefferson 3 Repowering 501G OTC** – This plan is similar to the ELI + Port Jefferson 3 Repowering 7FB **Plan**. In this plan, Port Jefferson 3 is retired in 2015 and the repowered unit, a

gas fired 501 G OTC combined cycle generator comes online in 2016. Rather than the use of ACC, this plan configuration uses Once-Through Cooling ("OTC") where water is drawn into the plan to absorb heat and then discharged at elevated temperature. The net output of the Port Jefferson Station increases by 157 MW. This plan requires the constructions of five new 501 G power plants over the 20 year study period.

Exhibit 9-15 Summary of Plans – Port Jefferson Repowering Technology Alternatives

ID	Plan Name	Energy Efficiency	Renewables				Upgrade Fleet			Inter-connection
			RPS	Wind	Fuel Cell	Solar	New	Repower	Retire	
H	Port Jefferson 3 Repowering 7FB ACC	ELI	25% x 2013	None	None	None	5 501G Starting in 2017	Port Jefferson 2016	None	None
O	Port Jefferson 3 Repowering 501G OTC	ELI	25% x 2013	None	None	None	5 501G Starting in 2018	Port Jefferson 2016	None	None

Results of Port Jefferson Repowering Technology Alternatives Plans

Exhibit 9-16 displays the dashboard results for the Port Jefferson Repowering Technology Alternatives plans. The first line of Exhibit 9-16 shows the absolute values for the ELI + Port Jefferson 3 Repowering 7FB ACC Plan. The second line shows the change between the alternative plan and this plan.

Compared to the ELI + Port Jefferson 3 Repowering 7FB ACC Plan, the repowering technology alternative presented here shows favorable results. Repowering Port Jefferson 3 with 501G OTC Plan shows a revenue requirement savings of $0.9 billion and an associated rate reduction of $0.2 Cents/kWh. Production efficiency is improved and CO_2 emissions remain unchanged. While once through cooing improves the performance of repowering at Port Jefferson, repowering at Port Jefferson is still slightly more expensive than not repowering. The cumulative annual revenue requirements over the 20-year study period are $111.5 billion for the ELI Plan described in section 9.4.1 and $111.7 for the Port Jefferson 3 Repowering 501G OTC Plan. While the use of once through cooling is clearly a better option, environmental regulations may prevent the licensing of this type of technology.

Exhibit 9-16 Port Jefferson Repowering Technology Alternatives – Results and Findings (2009-2028)

Plan	Reliability		Cost			Plan (2018 / 2028)				Emissions Target Years Met				CO_2 Emissions		
	New Generation (MW)	Capacity Criteria	Cum. Annual Rev. Req. ($Bil)	Cum. Annual Rev. Req., NPV	Avg. of Ann. Rev Rate (Cents/kW)	2018 Sales of Electricity (TWh)	2028 Sales of Electricity (TWh)	Avg. LI Sys Heat Rate, 2018 (BTU/kWh)	Avg. LI Sys Heat Rate, 2028 (BTU/kWh)	SO_2	NO_x	CO_2 Compliance	CO_2 Footprint	Cum. Compliance (mTons)	Cum Footprint (mTons)	Net Cost (Savings) per Footprint Reduction ($/ton)*
H) Port Jefferson 3 Repowering 7FB ACC	2,327	20	112.6	65.6	23.3	23.2	28.6	9,027	8,199	20	20	7	0	172	255	-
O) Port Jefferson 3 Repowering 501G OTC	113	20	-0.9	-0.4	-0.2	0.0	0.0	-67	-89	20	19	7	0	-0.4	-1	-1,334

9.4.5 Northport Repowering Technology Alternatives Group

The Repowering Option Group in Section 9.4.1 examined repowering using a common combined cycle technology with ACC. This group examines what happens when the technology used at the Northport site is varied.

Description of Northport Repowering Technology Alternatives Plans

Exhibit 9-17 shows four alternative plans used for the assessment of different repowering technologies at the Northport power plant. All four scenarios are identical in having the ELI efficiency program and 25% RPS program, but differ by using different repowering technology configurations. Because the net change in power output at the stations varies from plan to plan, the timing of the expansion plan after the repowering may vary.

- **ELI + Northport 1 Repowering 3x1 7FB ACC –** This plan is the repowering technology used in Section 9.4.1. Northport Unit 1 is repowered in 2016 with a 3x1 gas fired 7FB combined cycle generator in 2016. The net output of the Northport Station increases by 342 MW. The plan configuration is based on an ACC cooling system. This plan requires the construction of four new 501 G power plants over the 20 year study period**.**

- **Northport 4 Repowering 2x1 501G OTC** – This plan is to retire Northport Unit 4 in 2015 and repower with a gas fired 2x1 501G OTC combined cycle generator in 2016. The net output of the Northport Station increases by 315 MW. This plan requires the construction of four new 501 G power plants over the 20 year study period**.**

- **Northport 1&2 Repowering 3x1 7FB ACC** - This plan is identical to the "Northport 1 Repowering 3x1 7FB ACC" plan except that both Northport Units 1 and 2 are repowered a 3x1 gas fired 7FB combined cycle generator in 2016. The net output of the Northport Station decreases by 45 MW. The plan configuration is based on an ACC cooling system. This plan requires the construction of five new 501 G power plants over the 20 year study period with the first 501G coming online coincident with the Northport Repowered units for a total increase in net output in 2016 of 322 MW.

- **Northport 1&2 Repowering 3x1 7FB OTC** – This plan is similar to the "Northport 1&2 Repowering 3x1 7FB" plan but for the OTC configuration and the retirement of Northport 4 occurs one year earlier in 2015. The net output of the repowered Northport Station in 2016 decreases by 78 MW. The plan configuration is based on an OTC cooling system. This plan requires the construction of five new 501 G power plants over the 20 year study period with the first 501 G coming online coincident with the Northport Repowered units for a total increase in net output in 2016 of 289 MW.

Exhibit 9-17 Summary of Plans – Northport Repowering Technology Alternatives

ID	Plan Name	Energy Efficiency	Renewables				Upgrade Fleet			Inter-connection
			RPS	Wind	Fuel Cell	Solar	New	Repower	Retire	
I	Northport 1 Repowering 3x1 7FB ACC	ELI	25% x 2013	None	None	None	4 501G Starting in 2020	Northport 2016	None	None
P	Northport 4 Repowering 2x1 501G OTC	ELI	25% x 2013	None	None	None	4 501G Starting in 2020	Northport 2016	None	None
Q	Northport 1&2 Repowering 3x1 7FB ACC	ELI	25% x 2013	None	None	None	5 501G Starting in 2016	Northport 2016	None	None
R	Northport 3&4 Repowering 2x1 501G OTC	ELI	25% x 2013	None	None	None	5 501G Starting in 2016	Northport 2016	None	None

Results of Northport Repowering Technology Alternatives Plans

Exhibit 9-18 displays the dashboard results for the Northport Repowering Technology Alternatives plans. The first line of Exhibit 9-16 shows the absolute values for the ELI + Northport 1 Repowering 3x1 7FB ACC Plan. The remaining lines show the change between the alternative plans and this plan.

Compared to the ELI + Northport 1 Repowering 3x1 7FB ACC Plan, the repowering technology alternatives presented here show mixed results. Repowering Northport 4 with a 2x1 501G with OTC Plan shows a revenue requirement savings of $1.1 billion and an associate rate reduction of $0.5 Cents/kWh compared to the Northport 1 Repowering 3x1 7FB ACC Plan. Production efficiency is improved and CO_2 emissions drop slightly. As with the Port Jefferson OTC alternatives, there is a question whether environmental regulations will allow use of OTC at Northport. While the cumulative annual revenue requirements over the 20-year study period for the Northport 4 2x1 501G at $111.7 billion are $1.1 billion lower than the Northport 1 Repowering 3x1 7FB ACC Plan, it is still more expensive than the $111.5 billion cost of the ELI Plan described in section 9.4.1.

The last two plans explore the option of repowering two units at Northport instead of one. As with the Barrett analysis, retiring two units is more expensive than retiring one unit, but does have the benefit of providing power production efficiency gains and reductions in CO_2 emissions.

Exhibit 9-18 Northport Repowering Technology Alternatives – Results and Findings (2009-2028)

Plan	Reliability		Cost			Plan (2018 / 2028)				Emissions Target Years Met				CO_2 Emissions		
	New Generation (MW)	Capacity Criteria	Cum. Annual Rev. Req. ($Bil)	Cum. Annual Rev. Req., NPV	Avg. of Ann. Rev Rate (Cents/kW)	2018 Sales of Electricity (TWh)	2028 Sales of Electricity (TWh)	Avg. LI Sys Heat Rate, 2018 (BTU/kWh)	Avg. LI Sys Heat Rate, 2028 (BTU/kWh)	SO_2	NO_x	CO_2 Compliance	CO_2 Footprint	Cum. Compliance (mTons)	Cum Footprint (mTons)	Net Cost (Savings) per Footprint Reduction ($/ton)*
I) Northport 1 Repowering 3x1 7FB ACC	2,458	20	112.8	65.7	23.4	23.2	28.6	8,808	7,998	20	20	7	0	172	252	-
P) Northport 4 Repowering 2x1 501G OTC	-23	20	-1.1	-0.5	-0.2	0.0	0.0	-28	-21	20	20	7	0	-0.8	-1	-1,331
Q) Northport 1&2 Repowering 3x1 7FB ACC	367	20	0.8	0.4	0.2	0.0	0.0	-400	-116	20	20	7	0	2.1	4	-231
R) Northport 3&4 Repowering 2x1 501G OTC	344	20	-0.2	-0.1	0.0	0.0	0.0	-418	-150	20	20	7	0	3.1	-6	-30

9.4.6 Findings from Repowering Group Analyses

Taken in aggregate the findings from the evaluation of the five repowering groups are as follows:

- Repowering with conventional independent power producer financing increase costs to customers. The costs increases are smallest for Barrett, then Port Jefferson and then Northport (Section 9.4.1)
- The results of using 7FA, 7FB and 501G technologies are very close. This indicates that if LIPA issues a repowering RFP, the technology used for repowering should be left open to allow selection of the most cost effecting technology as part of the RFP (Sections 9.4.2, 9.4.4 and 9.4.5)
- Repowering two units instead of one during repowering tends to increase costs to consumers, improve power production efficiency and can have mixed results on CO_2 footprint emissions.(Sections 9.4.2 and 9.4.5)
- Using tax exempt financing for repowering saves customers money compared to taxable financing of repowering or taxable financing of new green field power plants. (Section 9.4.3)
- Once through cooling is economically preferable and can improve power production efficiency and in some cases reduce footprint CO_2 emissions. However, it is unclear whether environmental regulations will allow licensing of this technology. (Sections 9.4.4 and 9.4.5)

9.5 Retirement Options Group

The retirement options group looks at the possible retirement of several of the oldest generating units in the Long Island fleet. Some of the generating sites are so small that repowering may be impractical, leaving retirement as the best option. This analysis in combination with the repowering analysis can be used to compare repowering a unit against retirement of the unit with a new plant at another location.

Description of Retirement Options Plans

Exhibit 9-19 shows five alternative plans used for the assessment of different retirement options. All five scenarios are identical in having the ELI efficiency program and 25% RPS program, but differ by using different retirement options. Because the power output of the retired units varies from plan to plan, the timing and number of the expansion units varies from plan to plan.

- **ELI** – This plan, identical to the ELI Plan in the Efficiency Options Group, contains no repowering. It establishes a benchmark for comparing other retirement alternatives. This plan requires the construction of five new 501 G power plants over the 20 year study period.
- **Retire Barrett 1** – This plan is similar to the ELI Plan with the retirement of Barrett Unit 1 in 2016. The net output of the Barrett Station decreases by 195 MW. This plan requires the construction of five new 501 G power plants over the 20 year study period.
- **Retire Far Rockaway** – This plan is similar to the ELI Plan with the retirement of the 106 MW Far Rockaway Unit 4 in 2010. This plan requires the construction of five new 501 G power plants over the 20 year study period.
- **Retire Glenwood 4&5** – This plan is similar to the ELI Plan with the retirement of the 239 MW Glenwood 4&5 in 2010. This plan requires the construction of six new 501 G power plants over the 20 year study period.
- **Retire Glenwood 4&5 and Far Rockaway** – This plan is combines the "Retire Far Rockaway" and "Retire Glenwood 4&5" Plans. The 106 MW Far Rockaway Unit 4 and the 239 MW Glenwood 4&5 are retired in 2010. This plan requires the construction of six new 501 G power plants over the 20 year study period.

Exhibit 9-19 Summary of Plans –Retirement Options

ID	Plan Name	Energy Efficiency	Renewables				Upgrade Fleet			Inter-connection
			RPS	Wind	Fuel Cell	Solar	New	Repower	Retire	
E	ELI	ELI	25% x 2013	None	None	None	5 501G Starting in 2016	None	None	None
S	Retire Barrett 1	ELI	25% x 2013	None	None	None	5 501G Starting in 2016	None	Barrett1 2016	None
T	Retire Far Rockaway	ELI	25% x 2013	None	None	None	5 501G Starting in 2015	None	Far Rock 2010	None
U	Retire Glenwood 4&5	ELI	25% x 2013	None	None	None	6 501G Starting in 2014	None	Glenwood 2010	None
V	Retire Glenwood 4&5 and Far Rockaway	ELI	25% x 2013	None	None	None	6 501G Starting in 2013	None	Far Rock 2010; and Glenwood 2010	None

Results of Retirement Options Plans

Exhibit 9-20 displays the dashboard results for the Retirement Options plans. The first line of this exhibit shows the absolute values for the ELI Plan. Subsequent lines add the individual retirement of Barrett 1, Far Rockaway, Glenwood 4&5 and lastly the combined retirement of Glenwood 4&5 and Far Rockaway.

In general the retirement of any of these units results in improved production efficiency, lower CO_2 emissions, increased average annual revenue requirements as well as increased average rates.

Compared to the ELI Plan, adding the retirement of Barrett 1 would provide the same reliability benefit, increase revenue requirements over the study period by $0.5 billion, increase average annual rates by $0.1 cents/kWh, production efficiency would improve by an average of 3.7% in 2018 and 1.8% in 2028. CO_2 compliance emissions would be reduced by 1.4%. CO_2 footprint emissions would be reduced by 1.8%. The costs and benefits of the retirement of Barrett 1 are nearly identical to the costs and benefits of repowering Barrett 1 with a 501 G unit. This result may or may not apply to the retirement vs. repowering options at other stations.

Compared to the ELI plus RPS Plan, adding the retirement of Far Rockaway would provide the same reliability benefit, increase revenue requirements over the study period by $0.2 billion, increase average annual rates by $0.1 cents/kWh, and improve production efficiency by only a small fraction of a percent driven by the relatively low capacity factors these units operate. CO_2 compliance emissions would be reduced by 0.2% and CO_2 footprint emissions would increase by 0.5%.

Compared to the ELI plus RPS Plan, adding the retirement of Glenwood 4&5 would provide the same reliability benefit, the addition of 367 MW of new capacity, increase revenue requirements over the study period by $0.4 billion, increase average annual rates by $0.1 cents/kWh, production efficiency would improve by an average of 3.9% in 2018 and 2.4% in 2028. CO_2 compliance emissions would be reduced by 0.4% and CO_2 footprint emissions would be improved by 2.2%.

Compared to the ELI plus RPS Plan, adding the combined retirement of Glenwood 4&5 and Far Rockaway would result in less reliability benefit, the addition of 367 MW of new capacity, increase revenue requirements over the study period by $0.9 billion, increase average annual rates by $0.2 cents/kWh, production efficiency would improve by an average of 5.0% in 2018 and 2.5% in 2028. CO_2 compliance emissions would increase by 0.3% and CO_2 footprint emissions would be improved by 3.0%.

Exhibit 9-20 Retirement Options – Results and Findings (2009-2028)

Plan	Reliability		Cost			Plan (2018 / 2028)				Emissions Target Years Met				CO_2 Emissions		
	New Generation (MW)	Capacity Criteria	Cum. Annual Rev. Req. ($Bil)	Cum. Annual Rev. Req., NPV	Avg. of Ann. Rev Rate (Cents/kW)	2018 Sales of Electricity (TWh)	2028 Sales of Electricity (TWh)	Avg. LI Sys Heat Rate, 2018 (BTU/kWh)	Avg. LI Sys Heat Rate, 2028 (BTU/kWh)	SO_2	NO_x	CO_2 Compliance	CO_2 Footprint	Cum. Compliance (mTons)	Cum Footprint (mTons)	Net Cost (Savings) per Footprint Reduction ($/ton)*
E) ELI	2,090	20	111.5	65.0	23.1	23.2	28.6	9,307	8,269	20	16	7	0	172	259	-
S) Retire Barrett 1	0	20	0.5	0.3	0.1	0.0	0.0	-344	-151	20	19	7	0	-2.4	-5	101
T) Retire Far Rockaway	0	20	0.2	0.2	0.1	0.0	0.0	-5	-9	20	18	7	0	0.4	-1	201
U) Retire Glenwood 4&5	367	20	0.4	0.2	0.1	0.0	0.0	-361	-201	20	19	7	0	-0.7	-6	75
V) Retire Glenwood 4&5 and Far Rockaway	367	19	0.9	0.5	0.2	0.0	0.0	-467	-207	20	20	7	0	0.6	-7	125

Findings from Retirement Options Analysis

The findings from the Retirements Options Analysis are:

- Given the assumptions used for these scenarios, retirement increases costs and rates by a small percentage. However, if major environmental upgrades or costly repairs not captured in this analysis are required at a unit, retirement may be a breakeven or cost beneficial decision.

- Retirement of Far Rockaway is least costly to LIPA customers, followed by retirement of Glenwood 4&5 and then by the retirement of Barrett 1.

- Retirement has the benefit of improving production efficiency, and reducing Footprint CO_2 emissions.

- Retirement of Barrett 1 and Repowering of Barrett 1 with a 501 G combined cycle unit produce almost identical results, the only difference is due to costs specific to the site at which the 501 G plant is constructed (e.g., the repowered 501G at Barrett compared with a green field 501 G at another site located on Long Island).

9.6 Efficiency/Repowering Combinations Group

Section 9.3 examined energy efficiency options while Section 9.4 examined repowering. This group is used to evaluate how these two strategies interact with each other. It can help answer the questions of

- How does implementing energy efficiency affect the performance of repowering?

- How does implementing repowering affect the performance of energy efficiency?

Description of Efficiency/Repowering Combinations Plans

Exhibit 9-21 shows the four alternative plans used to investigate the interaction of Energy Efficiency programs and repowering. All four of the plans assume that LIPA continues to pursue implementation of the current 25% RPS program. Two levels of energy efficiency, ELI and 15x15 are examined against the repowering Barrett 1 with 2x1 7FA. The four plans are:

- **ELI** – This plan, identical to the ELI Plan in the Efficiency Options Group, contains no repowering. It establishes a benchmark for comparing other retirement alternatives. This plan requires the construction of six new 501 G power plants over the 20 year study period.

- **ELI + Repower Barrett 1 with 2x1 7FA** – This is identical to the ELI + Repower Barrett 1 with 2x1 7FA Plan evaluated in Section 9.4.2. It is based on the ELI Plan but includes repowering of Barrett Unit 1 with a gas fired 2x1 7FA combined cycle generator in 2016. The net output of the Barrett Station increases by 303 MW. This plan requires the construction of four new 501 G power plants over the 20 year study period.

- **15x15** – This plan, identical to the 15x15 Plan in the Efficiency Options Group and represents the 15 percent energy efficiency portion of Governor Paterson's 45 x 15 plan. The 15x15 Plan contains no repowering; rather, it establishes a benchmark for comparing other retirement alternatives. This plan requires the construction of two new 501 G power plants over the 20 year study period.

- **15x15 + Repower Barrett 1 with 2X1 7FA501G** – This is based on the 15x15 plan but includes repowering of Barrett Unit 1 with a gas fired 2x1 7FA combined cycle generator in 2025. Because of the higher level of energy efficiency, the need for a repowered unit is delayed from 2016 in the ELI Barrett 1 Repowering Plan to 2025 in the 15x15 Barrett 1 Repowering Plan. The net output of the Barrett Station increases by 303 MW. This plan requires the construction of one new 501 G power plants over the 20 year study period.

Exhibit 9-21 Summary of Plans – Repowering and Energy Efficiency Interaction

ID	Plan Name	Energy Efficiency	Renewables				Upgrade Fleet			Inter-connection
			RPS	Wind	Fuel Cell	Solar	New	Repower	Retire	
E	ELI	ELI	25% x 2013	None	None	None	5 501G Starting in 2016	None	None	None
G	ELI + Repower Barrett 1 with 2x1 7FA	ELI	25% x 2013	None	None	None	4 501G Starting in 2019	Barrett 1 2016	None	None
F	15 x 15	15 x 15	25% x 2013	None	None	None	2 501G Starting in 2025	None	None	None
W	15x15 + Repower Barrett 1 with 2X1 7FA	15 x 15	25% x 2013	None	None	None	1 501G Starting in 2027	Barrett1 2025	None	None

Results of Efficiency/Repowering Combinations Plans

The results of these alternative plans are shown in two different ways in Exhibit 9-22. The top section shows how increasing the level of energy efficiency affects the performance of repowering. The first two lines below the "Effect of Energy Efficiency on Repowering" header show the change in attributes when repowering occurs with the ELI program. Lines three and four show the change in attributes that occur when repowering is combined with the 15x15 efficiency program. Greater energy efficiency delays the repowering of the Barrett 1 unit from 2016 to 2025, delaying the start of losses caused by repowering. Since these losses are differed beyond the end of the study period, the impact of repowering on customers is smaller. The deferral of repowering also decreases the amount of environmental emission reductions caused by repowering. Increased energy efficiency also reduces the power production efficiency improvements caused by repowering.

The bottom section shows how repowering changes the costs and benefits incurred by moving from an ELI based energy efficiency program to a 15x15 based energy efficiency program. The first two lines below the "Effect of Repowering on Energy Efficiency" header show the change in attributes when increased energy efficiency efforts occur without repowering. Lines three and four show the change in attributes that occurs when increased energy efficiency efforts occurs are combined with repowering. Repowering improves the economic performance of the energy efficiency programs. The efficiency savings are augmented by the savings caused by delaying the added costs of repowering. However the environmental benefits of increasing energy efficiency are smaller when done in combination with repowering.

While, in combination, increasing energy efficiency and repowering tend to reduce the incremental benefits of each other, the combined strategies, when compared against pursuing neither option, are projected to still provide customer savings while increasing the total environmental and power production efficiency benefits.

Exhibit 9-22 Repowering and Energy Efficiency Interaction – Results and Findings 2009-2028)

Plan	Reliability		Cost			Plan (2018 / 2028)				Emissions Target Years Met				CO_2 Emissions		
	New Generation (MW)	Capacity Criteria	Cum. Annual Rev. Req. ($Bil)	Cum. Annual Rev. Req., NPV	Avg. of Ann. Rev Rate (Cents/kW)	2018 Sales of Electricity (TWh)	2028 Sales of Electricity (TWh)	Avg. LI Sys Heat Rate, 2018 (BTU/kWh)	Avg. LI Sys Heat Rate, 2028 (BTU/kWh)	SO_2	NO_X	CO_2 Compliance	CO_2 Footprint	Cum. Compliance (mTons)	Cum Footprint (mTons)	Net Cost (Savings) per Footprint Reduction ($/ton)*
Effect of Energy Efficiency on Repowering																
E) ELI	2,090	20	111.5	65.0	23.1	23.2	28.6	9,307	8,269	20	16	7	0	172	259	-
K) ELI + Repower Barrett 1 & 2 with 2x1 7FA	498	20	1.0	0.5	0.2	0.0	0.0	-484	-266	20	20	7	0	-2.5	20	-52
F) 15 x 15	989	20	104.2	61.6	23.9	20.7	25.6	9,715	8,899	20	19	13	0	144	244	-
W) 15x15 + Repower Barrett 1 with 2X1 7FA	131	20	0.2	0.1	0.0	0.0	0.0	0	-134	20	19	13	0	-0.8	-1	221
Effect of Repowering on Energy Efficiency																
E) ELI	2,090	20	111.5	65.0	23.1	23.2	28.6	9,307	8,269	20	16	7	0	172	259	-
F) 15 x 15	-1,101	20	-7.3	-3.4	0.8	-2.5	-3.1	408	630	20	19	13	0	-28.0	-15	-477
K) ELI + Repower Barrett 1 & 2 with 2x1 7FA	2,588	20	112.5	65.5	23.3	23.2	28.6	8,823	8,003	20	20	7	0	170	279	-
W) 15x15 + Repower Barrett 1 with 2X1 7FA	-1,468	20	-8.1	-3.8	0.6	-2.5	-3.1	892	762	20	19	13	0	-26.4	-35	-225

Findings from Efficiency/Repowering Combinations Analysis

The evaluation of the Efficiency/Repowering Combinations produces the following findings:

- Increased energy efficiency delays the need for new units or repowering and thus defers the losses incurred by repowering. However it also defers the environmental benefits from repowering.
- Repowering increases the customer cost savings from increased energy efficiency, but also reduces the environmental benefits obtained from increased levels of energy efficiency programs.
- While repowering and increased energy efficiency have a tendency to reduce the benefits of the other activity, the combined strategy still produces savings for LIPA's customers while reducing the overall level of environmental emissions.

9.7 Alternative Strategies Groups

Sections 9.2 to 9.5 addressed single strategy plans that used only one approach, like RPS, etc, to design the plan. Section 9.6 examined the interaction between energy efficiency and repowering. LIPA's Draft Electric Resource Plan must be able to meet multiple objectives, such as minimizing the impact on customer bills, meeting environmental targets, and maintaining reliability all while providing the flexibility to respond to change. To achieve these multiple objectives, a combination of strategies was found to provide the best results. These alternative plans were evaluated in two phases.

9.7.1 Alternative Strategies Phase I

Phase I Alternative Plans were developed as part of the initial plan outline. These plans are designed to test the effects of combining various options with the goal of finding a better plan than a single strategy plan.

Description of Alternative Strategies Phase I Plans

Exhibit 9-23 shows seven alternative plans used for the Phase I assessment of Alternative Strategies. These scenarios vary greatly in all aspects of their design including different levels of energy efficiency, renewables, retirements, repowering and new transmission interconnections.

- **Reference Plan** - This is the Reference Plan used in section 9.2 above. It establishes the yardstick against which to measure the other six Plans examined in this section. The Reference Plan assumes that no new energy efficiency programs are implemented after December 31, 2008. The effect of programs that were implemented prior to this date continues to provide benefits over the course of their useful life. This plan requires the construction of eight new 501 G power plants over the 20 year study period.

- **Continue CEI -** This plan, identical to the CEI Plan in the Efficiency Options Group, contains no repowering. This plan assumes that a program similar to the recently completed CEI program is implemented throughout the study period. This plan requires the construction of seven new 501 G power plants over the 20 year study period.

- **CEI + Repowering Focus –** This plan combines a small amount of energy efficiency programs with an aggressive repowering program. It uses the same energy efficiency from Continue CEI Plan and combines three repowering projects: (a) Repower Barrett Unit 1 with 2x1 7FA in 2015 increasing the net output of the Barrett Station by 303 MW; (b) Repower Northport Unit 1with 3x1 7FB ACC in 2017 increasing the net output of the Northport Station by 350 MW; and, (c) Repower Port Jefferson Unit 3 with 1x1 7FB ACC increasing the net output of the Port Jefferson Station by 246 MW. This plan requires the construction of four new 501 G power plants over the 20 year study period.

- **Low Operating Cost Focus –** This plan is based on using capital intensive projects with low operating costs. It uses CEI energy efficiency program combined with the implementation of LIPA's Automated Meter Initiative ("AMI"), a "smart meter" program. The resources in this plan are based on an expansion of LIPA's undersea transmission cables. In 2016, the 229 MW upgrade of the NUSCO Cable is placed into service and provides for the additional capability for the purchase 143 MW from the ISO-NE market. This plan assumes a second undersea cable rated at 1000 MW interconnecting with the PJM market in New Jersey coupled with a contract for the 20 year contract for the purchase of capacity and energy from a new nuclear unit located in PJM. This plan requires the construction of three new 501 G power plants over the 20 year study period.

- **15x15** – This plan, identical to the 15x15 Plan in the Efficiency Options Group. This plan requires the construction of two new 501 G power plants over the 20 year study period.

- **Environmental Focus** – This plan is designed to use measures that may be considered environmentally friendly including an aggressive energy efficiency program, high use of renewable energy, repowering and unit retirement. The plan combines the 15 x 15 energy efficiency program with two plant retirements: (a) 106 MW Far Rockaway Unit 4 in 2009; and

(b) 239 MW Glenwood 4&5 in 2010 and two repowering projects: (a) Repower Barrett Unit 1 with 2x1 7FA in 2014 increasing the net output of the Barrett Station by 303 MW; and (b) Repower Northport Unit 1with 3x1 7FB ACC in 2016 increasing the net output of the Northport Station by 350 MW. In addition, the plan includes 6x 144 MW wind farms and 10x 10 MW fuel cell stacks installed in consecutive years beginning in 2012. This plan requires no new 501 G power plants over the 20 year study period.

- **Market Access Focus** – This plan combines an aggressive energy efficiency program with a policy of connecting to neighboring systems. It uses the "15x15" energy efficiency program. In 2025, the upgrade of the NUSCO Cable is placed into service and provides for the additional capability for the purchase 143 MW from the ISO-NE market. In 2026, a second 1000 MW undersea cable interconnecting with the PJM market in New Jersey coupled with a contract for the 20 year contract of capacity only. This assumes the economy energy purchases PJM This plan requires no new 501 G power plants over the 20 year study period.

Exhibit 9-23 Summary of Plans – Alternative Strategies Phase I

ID	Plan Name	Energy Efficiency	Renewables				Upgrade Fleet			Inter-connection
			RPS	Wind	Fuel Cell	Solar	New	Repower	Retire	
A	Reference Plan	None	None	None	None	None	8 501G Startin g in 2014	None	None	None
D	Continue CEI	CEI	25% x 2013	None	None	None	7 501G Startin g in 2015	None	None	None
X	CEI + Repowering Focus	CEI	25% x 2013	None	None	None	4 501G Startin g in 2021	Barrett1 2015; Northport1 2017; and Port Jefferson3 2019	None	None
Y	Low Operating Cost Focus	CEI (and AMI)	25% x 2013	None	None	None	3 501G Startin g in 2024	None	None	NUSCO Upgrade 2016; 1000 MW PJM w/ Nuclear 2017
F	15 x 15	15 x 15	25% x 2013	None	None	None	2 501G Startin g in 2025	None	None	None
Z	Environmen tal Focus	15 x 15	30% x 2015	6 144 MW Startin g in 2012	100 MW Fuel Cells beg. 2012	None	None	Barrett1 2014; Northport in 2016	Far Rock 12/31/2 009; and Glenwo od 12/31/2 010	None

AA	Market Access Focus	15 x 15	25% x 2013	None	None	None	None	None	None	NUSCO Upgrade 2025; 1000 MW PJM 2026

Results of Alternative Strategies Phase I Plans

Exhibit 9-24 displays the dashboard results for the Alternative Strategies Phase I plans. The first line of this exhibit shows the absolute values for the Reference Plan. Similar to the previously discussed dashboards, the remaining lines show the change between the alternative plans and the Reference Plan. The Reference Plan has the lowest average rates among the alternative plans considered in this section. This is partially driven by the absence of an RPS program and energy efficiency program, the repercussion of which is that the Reference Plan is one of the worst performing plans from a CO_2 emissions perspective.

Compared to the Reference Plan, continuing with CEI would reduce the additional new capacity required by 367 MW. Revenue requirements over the study period would decrease by $0.4 billion, average annual rates would increase by 0.4 cents/kWh, sales of electricity would decrease by 0.7 TWh, and production efficiency would worsen by an average of 0.8% in 2018 and improve by 0.4% in 2028. CO_2 compliance emissions would be reduced by 2.8% and CO_2 footprint emissions would be improved by 11.6%.

Compared to the Reference Plan, combining continuing CEI with a Repowering Focus Plan would increase the additional new capacity required by 386 MW. Revenue requirements over the study period would increase by $2.4 billion, average annual rates would increase by 0.9 cents/kWh, sales of electricity would decrease by 0.7 TWh, and production efficiency would improve by an average of 9.6% in 2018 and improve by 5.5% in 2028. CO_2 compliance emissions would be reduced by 2.8% and CO_2 footprint emissions would be improved by 16%. This plan is one of the best plans for improving power production efficiency since it relies extensively on repowering old plants and building new plants. Unfortunately compared to the Reference Plan, it increases total costs to customers and shows moderate reductions in CO_2 emissions.

Compared to the Reference Plan, the Low Operating Cost Focus Plan would reduce the amount of additional new capacity by 692 MW. Revenue requirements over the study period would increase by $5.8 billion, average annual rates would increase by 1.6 cents/kWh, sales of electricity would decrease by 0.7 TWh, and production efficiency would worsen by an average of 12.2% in 2018 and improve by 13.7% in 2028. CO_2 compliance emissions would be reduced by 23% and CO_2 footprint emissions would be improved by23%. Relative to the Reference Plan, this plan increases total customer costs the most, and has the second highest rate increases. It is the second best performer in reducing the CO_2 footprint.

Compared to the Reference Plan, the 15 x 15 Plan would reduce the amount of additional new capacity by 2,202 MW. Revenue requirements over the study period would be reduced by $11.5 billion, average annual rates would increase by 1.2 cents/kWh, sales of electricity would decrease by 4.0 TWh in 2018 and 5.0 TWh in 2028, and production efficiency would worsen by an average of 7.8% in 2018 and 9.9% in 2028. CO_2 compliance emissions would be reduced by 25% and CO_2 footprint emissions would be improved by 17%. The 15x15 Plan is a close second in reducing customer's total costs compared to the Reference Plan. However, compared to the Reference Plan it decreases power production efficiency and performs moderately in the area of reducing the CO_2 footprint.

Compared to the Reference Plan, the Environmental Focus Plan would reduce the amount of additional new capacity by 730 MW. Revenue requirements over the study period would increase by $3.2 billion, average annual rates would increase by 4.6 cents/kWh, sales of electricity would decrease by 4.0 TWh in 2018 and 5.0 TWh in 2028, and production efficiency would improve by an average of 9.6% in 2018 and worsen by 0.8% in 2028. CO_2 compliance emissions would be reduced by 25% and CO_2 footprint emissions would be improved by 25%. Compared to the Reference Plan, the Environmental focus has the best performance in reducing CO2 emissions, but has by far the largest rate increase and the second highest customer total cost increases among the plans evaluated in this section. The high costs are driven by heavy reliance upon renewable energy sources.

Compared to the Reference Plan, the Market Focus Plan would reduce the amount of additional new capacity by 1,793 MW. Revenue requirements over the study period would decrease by $12.2 billion, average annual rates would increase by 1.1 cents/kWh, sales of electricity would decrease by 4.0 TWh in 2018 and 5.0 TWh in 2028, and production efficiency would worsen by an average of 7.8% in 2018 and 24% by in 2028. CO_2 compliance emissions would be reduced by 27% and CO_2 footprint emissions would be improved by 12%. The Market Focus Plan provides the greatest overall customer cost reductions compared to the Reference Plan. However it is only moderately effective in reducing the environmental footprint and has the worst production efficiency of all of the alternative plans.

Exhibit 9-24 Alternative Strategies Phase I – Results and Findings (2009-2028)

	Reliability		Cost			Plan (2018 / 2028)				Emissions Target Years Met				CO_2 Emissions		
Plan	New Generation (MW)	Capacity Criteria	Cum. Annual Rev. Req. ($Bil)	Cum. Annual Rev. Req., NPV	Avg. of Ann. Rev Rate (Cents/kW)	2018 Sales of Electricity (TWh)	2028 Sales of Electricity (TWh)	Avg. LI Sys Heat Rate, 2018 (BTU/kWh)	Avg. LI Sys Heat Rate, 2028 (BTU/kWh)	SO_2	NO_x	CO_2 Compliance	CO_2 Footprint	Cum. Compliance (mTons)	Cum Footprint (mTons)	Net Cost (Savings) per Footprint Reduction ($/ton)*
A) Reference Plan	3,191	20	115.7	66.9	22.7	24.7	30.5	9,013	8,099	20	18	6	0	191	295	-
D) Continue CEI	-367	20	-0.4	-0.2	0.4	-0.7	-0.7	75	-30	20	16	6	0	-5.4	-34	-10
X) CEI + Repowering Focus	386	20	2.4	1.2	0.9	-0.7	-0.7	-861	-443	20	20	7	0	-5.3	-47	53
Y) Low Operating Cost Focus	-692	20	5.8	2.9	1.6	-0.7	-0.7	1,100	1,114	20	17	14	1	-43.8	-68	89
F) 15 x 15	-2,202	20	-11.5	-5.3	1.2	-4.0	-5.0	703	800	20	19	13	0	-47.5	-50	-223
Z) Environmental Focus	-730	20	3.2	2.6	4.6	-4.0	-5.0	-865	61	20	20	9	10	-48.6	-73	49
AA) Market Access Focus	-1,793	20	-12.2	-5.6	1.1	-4.0	-5.0	703	1,908	20	19	16	0	-52.0	-35	-345

Findings from Alternative Strategies Phase I Analysis

The following finding can be determined from the evaluation of the Alternative Strategies Phase I group.

- The lowest total customer cost plans are the 15 x 15 Plan and the Market Access Focus Plan which both contain the 15 x 15 program. These plans also have the benefit of reducing CO_2 emissions while reducing customer costs.
- The Reference Plan has the lowest rate among all of the plans considered, but is about $12 billion more expensive to consumers than the most cost effective plans. All other plans result in higher rate increases relative to the Reference Plan.
- The CEI + Repowering Focus Plan and Environmental Focus Plan have the best power production efficiency because of their reliance upon repowering.

- The best performing plans from a CO_2 emissions perspective rely heavily upon zero emission technologies such as renewable and nuclear power. However, these technologies are expensive and make these plans the most expensive evaluated in this group.

9.7.2 Alternative Strategies Phase II Group

Phase II Alternative Plans, developed after the evaluation of all of the analysis presented so far, were designed to further refine the development of the plan that would be selected as the Representative Plan. The objective of the Alternative Strategies Phase II Group was to develop a plan that achieves, relative to the Reference Plan, reductions in total customer costs, improvements in power production efficiency, and significant CO_2 emissions reductions while moderating customer rate increases.

Description of Alternative Strategies Phase II Plans

Exhibit 9-25 shows seven alternative plans used for the Phase II assessment of Alternative Strategies. The first three plans were carried over from the Phase I assessment while the last four plans were developed from Phase I findings.

- **Reference Plan** - This is the Reference Plan in the first line in section 9.7.1 above.
- **15x15** – This is the 15x15 Plan in the fifth line in the exhibits in Section 9.7.1.
- **Environmental Focus** – This is the Environmental Focus Plan on the sixth line in the exhibits in Section 9.7.1.
- **15 x15 Repowering Plan –** This plan was designed to use most of the recommendations contained in the Recommended Electric Resource Plan shown in Exhibit 1-1 while lowering costs compared to the Reference Plan. This plan is based on the "15x15" plan and includes two retirements in 2012: (a) 106 MW Far Rockaway Unit 4; and (b) 239 MW Glenwood 4&5. Three repowering projects: (a) Repower Barrett Unit 1 with 501G ACC in 2016 increasing the net output of the Barrett Station by 172 MW; (b) Repower Northport Unit 4 with 2x1 501G ACC in 2019 increasing the net output of the Northport Station by 315 MW; and, (c) Repower Port Jefferson Unit 3 with 1x1 501G ACC increasing the net output of the Port Jefferson Station by 157 MW in 2022. In addition, the plan includes 100 MW of solar installed annually beginning in 2010 on sites ranging in size from 10 MW to 30 MW and a 10% share in a 300 MW wind farm in 2015 (LIPA share is 150 MW). Lastly, in 2016, the upgrade of the NUSCO Cable is placed into service and provides for the additional capability for the purchase 143 MW from the ISO-NE market. This plan requires no new 501 G power plants over the 20 year study period. This plan results in surplus capacity during the middle of the planning period.
- **15 x 15 Retirement Plan –** This plan is designed to address the capacity surpluses in the 15 x 15 Repowering Plan by reducing the amount of repowered capacity. This plan is nearly identical to the "15x15 Repowering Plan" but for two differences: (a) Only one repowering project (Barrett Unit 1 repowered in 2016 with 2x1 7FA, increasing the net output of the Barrett Station by 303 MW); and (b) three new 501 G power plants are required over the 20 year study period.
- **Representative Plan** – This plan takes a different approach to the capacity surplus in the 15x15 Repowering Plan. This plan is the same as the 15 x 15 Repowering Plan except that when a unit is repowered, it is assumed that two generating units instead of one unit are taken out of service at the station. The three repowering projects have the following net impact (a) Repower Barrett Units 1&2 with 501G ACC in 2016 decreasing the net output of the Barrett Station by 16 MW; (b) Repower Northport Unit 3&4 with 2x1 501G OTC in 2019 decreasing the net output of the

Northport Station by 78 MW; and, (c) Repower Port Jefferson Unit 3&4 with 1x1 501G OTC decreasing the net output of the Port Jefferson Station by 40 MW in 2022. Because, with this plan, repowering reduces capacity at the power stations instead of increasing power output, this plan requires three new 501 G power plants over the 20 year study period. The retirement, renewables and NUSCO upgrade details of this plan are identical to the 15x15 Repowering Plan above.

- **Representative Plan with Oil Ban** – This plan was designed to see how much of the CO2 emissions in the Representative Plan were attributable to oil usage. This plan is identical to the Representative Plan; however, it assumes that all existing steam units are required to burn only natural gas (and are banned from burning oil). This plan does not take into the account the need to secure firm uninterruptible gas supply and transportation for the power plants. This cost is likely to be substantial.

Exhibit 9-25 Summary of Plans – Alternative Strategies Phase II

ID	Plan Name	Energy Efficiency	Renewables				Upgrade Fleet			Inter-connection
			RPS	Wind	Fuel Cell	Solar	New	Repower	Retire	
A	Reference Plan	None	None	None	None	None	8 501G Starting in 2014	None	None	None
F	15 x 15	15 x 15	25% x 2013	None	None	None	2 501G Starting in 2025	None	None	None
Z	Environmental Focus	15 x 15	30% x 2015	6 144 MW Starting in 2012	100 MW Fuel Cells beg. 2012	None	None	Barrett1 2014; Northport in 2016	Far Rock 12/31/2009; and Glenwood 12/31/2010	None
BB	15 x15 Repowering Plan	15 x 15	30% x 2015	150 MW Starting in 2015	None	100 MW 2010-15	None	Barrett 1 2016; Northport4 2019; Port Jefferson3 2022	Far Rock 2012; and Glenwood 2012	NUSCO Upgrade 2016
CC	15 x 15 Retirement Plan	15 x 15	30% x 2015	150 MW Starting in 2015	None	100 MW 2010-15	3 501G Starting in 2022	Barrett 1 2016	Far Rock 2012; and Glenwood 2012	NUSCO Upgrade 2016
DD	Representative Plan	15 x 15	30% x 2015	150 MW Starting in 2015	None	100 MW 2010-15	3 501G Starting in 2024	Barrett 1&2 2016; Northport 3&4 2019; Port Jefferson 3&4 2022	Far Rock 2012; and Glenwood 2012	NUSCO Upgrade 2016

EE	Representative Plan with Oil Ban	15 x 15	30% x 2015	150 MW Starting in 2015	None	100 MW 2010-15	3 501G Starting in 2024	Barrett 1&2 2016; Northport 3&4 2019; Port Jefferson 3&4 2022	Far Rock 2012; and Glenwood 2012	NUSCO Upgrade 2016

Results of Alternative Strategies Phase II Plans

Exhibit 9-26 displays the dashboard results for the Alternative Strategies Phase II plans. Similar to the previous dashboard the first line of this exhibit shows the absolute values for the Reference Plan. The remaining lines show the change between the alternative plans and the Reference Plan. As a group these alternative plans offer the greatest opportunities for emission reductions and lower revenue requirements over the life of the study.

Since the 15 x 15 Plan and the Environmental Focus Plan were described in 9.7.1, the summary of the plan results are not repeated here.

Compared to the Reference Plan, the 15x15 Repowering Plan would reduce the additional new capacity by 1,380 MW. Revenue requirements over the study period would decrease by $6.1 billion, average annual rates would increase by $2.4 cents/kWh, sales of electricity would decrease by 4.0 TWh in 2018 and 5.0 TWh in 2028, and production efficiency would worsen by an average of 0.4% in 2018 and improve by 2.4% in 2028. CO_2 compliance emissions would be reduced by 26% and CO_2 footprint emissions would be improved by 25%. This plan provides CO_2 footprint emissions at a level similar to the Environmental Focus while reducing revenue requirement compared to the Reference Plan.

Compared to the Reference Plan, the 15x15 Retirement Plan would reduce the additional new capacity by 1,341 MW. Revenue requirements over the study period would decrease by $6.4 billion, average annual rates would increase by $2.4 cents/kWh, sales of electricity would decrease by 4.0 TWh in 2018 and 5.0 TWh in 2028, and production efficiency would worsen by an average of 0.4% in 2018 and improve by 1.4% in 2028. CO_2 compliance emissions would be reduced by 28% and CO_2 footprint emissions would be improved by 24%. This plan reduces revenue requirements more than the 15x15 Repowering Plan, but is less effective in reducing CO_2 footprint emissions.

Compared to the Reference Plan, the Representative Plan would reduce the additional new capacity by 279 MW. Revenue requirements over the study period would decrease by $5.0 billion, average annual rates would increase by $2.7 cents/kWh, sales of electricity would decrease by 4.0 TWh in 2018 and 5.0 TWh in 2028, and production efficiency would improve by an average of 0.2% in 2018 and 8.6% by 2028. CO_2 compliance emissions would be reduced by 26% and CO_2 footprint emissions would be improved by 26%. With the exception of the Oil Ban Plan below, when compared to the Reference Plan, the Representative Plan shows the largest reduction in CO_2 footprint emissions and the best long-term improvement in power production heat rate, but achieves this at the expense of fewer reductions in revenues requirements than the other new alternative plans.

Compared to the Reference Plan, the Representative Plan with Oil Ban would reduce revenue requirements over the study period by $5.0 billion and average annual rates would increase by $2.7 cents/kWh. However, these costs do not include the cost of securing firm non-interruptible gas supplies for the gas-fired power plants on Long Island. Also the models used do not capture the added costs of more volatile gas prices. The oil ban primarily impacts production efficiency and the associated environmental emissions. Production efficiency would improve by an average of 2.1% in 2018 and 9.6% by 2028. CO_2 compliance emissions would be reduced by 34% and CO_2 footprint emissions would be improved by 29%. While not shown on the dashboard, this plan would decrease fuel diversity by increasing dependence upon natural gas and would make Long Island much more susceptible to supply interruptions.

Exhibit 9-26 Alternative Strategies Phase II – Results and Findings (2009-2028)

	Reliability		Cost			Plan (2018 / 2028)				Emissions Target Years Met				CO_2 Emissions		
Plan	New Generation (MW)	Capacity Criteria	Cum. Annual Rev. Req. ($Bil)	Cum. Annual Rev. Req., NPV	Avg. of Ann. Rev Rate (Cents/kW)	2018 Sales of Electricity (TWh)	2028 Sales of Electricity (TWh)	Avg. LI Sys Heat Rate, 2018 (BTU/kWh)	Avg. LI Sys Heat Rate, 2028 (BTU/kWh)	SO_2	NO_x	CO_2 Compliance	CO_2 Footprint	Cum. Compliance (mTons)	Cum Footprint (mTons)	Net Cost (Savings) per Footprint Reduction ($/ton)*
A) Reference Plan	3,191	20	115.7	66.9	22.7	24.7	30.5	9,013	8,099	20	18	6	0	191	295	-
F) 15 x 15	-2,202	20	-11.5	-5.3	1.2	-4.0	-5.0	703	800	20	19	13	0	-47.5	-50	-223
Z) Environmental Focus	-730	20	3.2	2.6	4.6	-4.0	-5.0	-865	61	20	20	9	10	-48.6	-73	49
BB) 15 x15 Repowering Plan	-1,380	20	-6.1	-2.5	2.4	-4.0	-5.0	33	-197	20	20	11	3	-49.3	-75	-77
CC) 15 x 15 Retirement Plan	-1,341	20	-6.4	-2.7	2.4	-4.0	-5.0	33	-116	20	20	16	3	-54.2	-70	-86
DD) Representative Plan	-279	20	-5.0	-2.1	2.7	-4.0	-5.0	-21	-696	20	20	15	3	-49.2	-78	-60
EE) Representative Plan with Oil Ban	-279	20	-5.0	-2.0	2.7	-4.0	-5.0	-189	-780	20	20	16	9	-64.6	-86	-52

Findings from Alternative Strategies Phase II Analysis

The findings from the Alternative Strategies Phase II include

- A detailed study of the implications on reliability and costs should be considered before selecting a plan that bans the use of oil.
- All of the new Phase II plans are much more cost effective than the Environmental Focus Plan and the Reference Plan. However, rates are higher than the Reference Plan.
- All of the new Phase II plans are much more effective at reducing CO_2 footprint emissions than the 15 x 15 Plan. In aggregate, consumers save money for each ton of emissions reduced in each of these plans.
- The 15x15 Retirement Plan creates a long term supply surplus that would be difficult to justify.
- The greatest long term improvement in production efficiency comes from the Representative Plan and Representative Plan with Oil Ban.

With the exception of the Representative Plan with Oil Ban Plan, any of the alternative plans introduced in Phase II could justifiably be selected to be the Representative Plan. The Representative Plan was selected because, it provides the greatest CO2 footprint reductions, the best power plant efficiency improvement while, relative to the Reference Plan saving customers money over the long term. The next section describes the Representative Plan in greater detail.

9.8 Description of Representative Plan

The Recommended Electric Resource Plan, as described in Exhibit 1-1 of the Draft Electric Resource Plan document, incorporates a number of actions that are either committed, planned or under study which renders a direct calculation of benefits difficult, since it is not known how it will actually be implemented. LIPA has selected a "Representative Plan" which models adopting one possible set of these actions that represent implementation of the recommended plan to illustrate the potential benefits of the Recommended Plan.

9.8.1 Overview of Representative Plan Elements

Section 1.1 of the Draft Electric Resource Plan describes the framework of the Recommended Plan which adopts four key strategies:

1. Committed investment in energy efficiency,
2. Acquisition of renewable generation resources,
3. Maintaining and upgrading our existing fleet of resources, and
4. Improving transmission interconnections to enhance the ability to deliver power to Long Island.

The specific tactics that support the four key strategies were identified in Exhibit 1-1 as either committed, planned or under study. Exhibit 9-27 shows the same set of strategies with color coding that indicates whether each tactic was modeled in the Representative Plan (**green**) or not (**grey**) . The following subsections explain how each of the strategies is modeled in the Representative Plan and help make it effective.

Exhibit 9-27 Representative Plan

1. Energy Efficiency

- Endorse adoption of a LIPA 15 x 15 plan
  - End-use efficiency
    - ELI
    - Additional DSM to close remaining gap
  - Generation efficiency
  - T&D efficiency
  - Smart Meters
  - Efficient Electro-Technologies

2. Renewable Resources

- Endorse adoption of a LIPA RPS program that supports statewide goal of 30% renewables by 2015
- Off-Island Renewable RFP
- On-Island Resources
  - Wind (regional and backyard)
  - PV 50 MW RFP and successors
  - Net Metering Program
  - Expansion of Solar Rebate
- Utilize renewables to enhance fuel diversity

3. Upgrade Existing Fleet

- Repower older plants to address environmental and efficiency issues
- Competitive procurement of green field plants and repowering/retirement
- Retire some of older steam plants
- Study best site for Peaking Unit retirements
  - Issue RFP for new 10-minute reserve
  - Retire targeted units

4. Improve Interconnections & Reliability

- Proceed with NUSCO Upgrade
- Study to examine membership in NYISO, PJM, or ISO-NE
- Target new interconnections with best ISO System
- SmartGrid System

Legend: Modeled in Representative Plan | Not Modeled in Representative Plan

9.8.2 Energy Efficiency

Energy Efficiency supports the plan in several different ways. First and foremost, it saves LIPA's customers money relative to the Reference Plan by reducing the amount of energy used by customers. Secondly, by reducing the amount of fossil fuel consumed to serve the customers, it reduces LIPA's CO_2 footprint. However, energy efficiency alone does not reach the LIPA CO_2 emission footprint target. The cost savings from energy efficiency help fund additional measures to further reduce the LIPA CO_2 emissions footprint.

The Representative Plan models all of the tactics in the Energy Efficiency strategy. LIPA has a long history of successful energy efficiency, having recently completed its 10 year Clean Energy Initiative at the end of 2008. Looking forward, the Representative Plan is designed to implement the programs identified as components of the 15 x 15 program, which include:

- End-use efficiency programs including ELI and additional DSM to close remaining gap such that LIPA achieves a 15% savings by 2015
- Generation efficiency measures
- Internal generation and T&D system measures

- Smart Meters
- Efficient Electro-Technologies

In addition, the implementation of 15 x 15 coincides with New York State's efforts to achieve its 15 x 15 goals. The Representative Plan includes promoting the adoption of higher New York State building codes and appliance standards.

The conclusions from the comparison with the Reference Plan, these efficiency measures produced significant benefits including:

- Reducing CO_2 emissions from LIPA contractual plants
- Energy efficiency options are among the most cost effective options available for CO_2 footprint reductions
- Reducing LIPA's energy requirements provides LIPA with the opportunity to retire older steam plants without requiring the addition of new green field plants

9.8.3 Upgrade Existing Fleet

Upgrading the Existing Fleet improves the efficiency of power production. The alternative plan analysis indicates that repowering and retirement are slightly more expensive than continuing to operate the plant. However, the production efficiency improvements from repowering and retirement are effective in reducing LIPA's CO_2 emissions footprint. Building new power plants can have the same effect when it displaces production from older, less efficient plants. In the plan the slightly higher cost of retirement and repowering is funded through savings obtained from the energy efficiency programs. Significantly, power plants are able to, within operating limits, produces electricity when needed (dispatchable). Since electricity must be produced as it is consumed and the most viable renewable resources like solar and wind are intermittent in nature, efficient dispatchable resources are critical to supporting the plan.

The Representative Plan incorporates the majority of the tactics set forth in Exhibit 1-1. The upgrading of the existing fleet through retirement, repowering and competitive procurement of green field plants is made possible when implemented alongside the aggressive Energy Efficiency Plan. When a plant is retired, LIPA has to replace the capacity of that plant in order to maintain its reliability criteria. The Energy Efficiency tactics incorporated in the Representative Plan mitigate the need for new resources to accommodate steam plant retirements in the early years of the plan.

The Representative Plan includes:

- Competitive procurement of green field plants and repowering/retirement
    - Caithness in 2009
    - Barrett (repower) in 2016
    - Northport (repower) in 2019
    - Port Jefferson (repower) in 2022
    - 3 green field 501G plants in 2024, 2026, and 2028
- Retire some of older steam plants

  - Glenwood 4 in 2011
  - Glenwood 5 in 2011
  - Far Rockaway 4 in 2011
  - Barrett 1 in 2016 (for repowering)
  - Barrett 2 in 2016 (for repowering)
  - Northport 4 in 2018 (for repowering)
  - Northport 3 in 2019 (for repowering)
  - Port Jefferson 3 in 2021 (for repowering)
  - Port Jefferson in 2021 (for repowering)

9.8.4 Renewable Resources

Renewable resources significantly reduce the amount of energy that must be produced with fossil fuels, which reduces the amount of electricity that must be produced with fossil fuels. The disadvantages of renewable power supplies today are that they are more expensive than conventional sources. Secondly the most promising resources are intermittent in nature and require backup resources when they are unable to produce power. The energy efficiency strategy provides cost savings to help fund renewables and the upgraded fleet provides the backup power for the intermittent nature of some renewables.

The Representative Plan endorses the adoption of a LIPA RPS program that supports statewide goal of 30% renewables by 2015. To meet this goal, all of the Renewable Resources tactics were implemented. The benefits of the renewable resource tactics included a reduction in LIPA's footprint CO_2 as well as an enhancement of its fuel diversity, effectively reducing reliance on fossil fuels.

To achieve its target, the Representative Plan approaches Renewable Resources both On and Off-Island, employing both resource additions as well as providing incentives for customer sited renewable resources. The Representative Plan includes

- New On-Island Resources
  - A 50% share in a new off-shore 300 MW wind farm (150 MW)
  - 50 MW Solar RFP plus a second 50 MW Solar RFP
- Net Metering Program
- Expansion of Solar Rebate
- Off-Island purchase of RPS eligible renewable energy to meet its targets via bilateral purchases from upstate New York, PJM, and ISO-NE

9.8.5 Improve Interconnections & Reliability

Improved interconnection and reliability reduces the number of power resources that must be built on Long Island. Improved interconnections, depending upon how they are used, can either help attain or work against attaining the goal of reducing CO_2 emissions footprint. If the interconnections are used to import power from renewable contracts, the CO_2 emissions footprint can be reduced. Historically, renewable resources from off-Island resources are less expensive than from on-Island resources. Thus interconnections can reduce the cost of attaining renewable power objectives. Alternatively, importing gas from new combined cycle generating units can be neutral from an emissions footprint perspective.

LIPA's 2004 Energy Plan already accomplished much with almost 1,200 MW of transmission enhancements (Cross Sound Cable, Neptune and NUSCO cable replacement). The Representative Plan incorporates the following interconnection and reliability elements:

- The Brookfield Energy contract will begin delivery of RPS qualified energy starting in June 2009.
- The PPL Landfill Gas contract will begin delivery of RPS qualified energy starting in June 2009.
- Marcus Hook is scheduled to begin delivering capacity to LIPA over the Neptune Cable in 2010. This capacity from a new, gas-fired combined cycle unit enhances the reliability of supply over the Neptune Cable and reduces LIPA's susceptibility to price fluctuations in the capacity spot markets.
- Upgrade of the NUSCO cable in 2016. This upgrade strengthens its interconnection with ISO-NE.
- The RPS modeling assumes that the much of the power will be delivered over LIPA's interconnections.

9.8.6 Representative Plan Timeline

Exhibit 9-28 shows a timeline of how the resources are modeled in the representative plan. The Representative Plan moves LIPA toward a more sustainable power supply through the adoption of end-use and system energy efficiency programs, introduction of additional renewable resources and replacement of existing generation with more efficient generating resources. The integration of these strategies into the Representative Plan provides for:

- LIPA to meet its 15 x 15 target and continue its efficiency programs thereafter
- LIPA to meet its RPS target and continue its RPS programs thereafter
- 3 repowered gas fired combined cycle units
- The retirement of 9 old steam units (including 6 retired in conjunction with repowering)
- 4 new gas fired combined cycle units
- 100 MW of solar installations
- 150 MW of wind
- Expansion of customer sited renewables through Net Metering program and the expansion of the Solar Rebate
- Renewable energy from off-Island sources including Brookfield Energy Contract and PPL landfill gas contract
- Upgrade of the NUSCO cable

Exhibit 9-28 Representative Plan Timeline

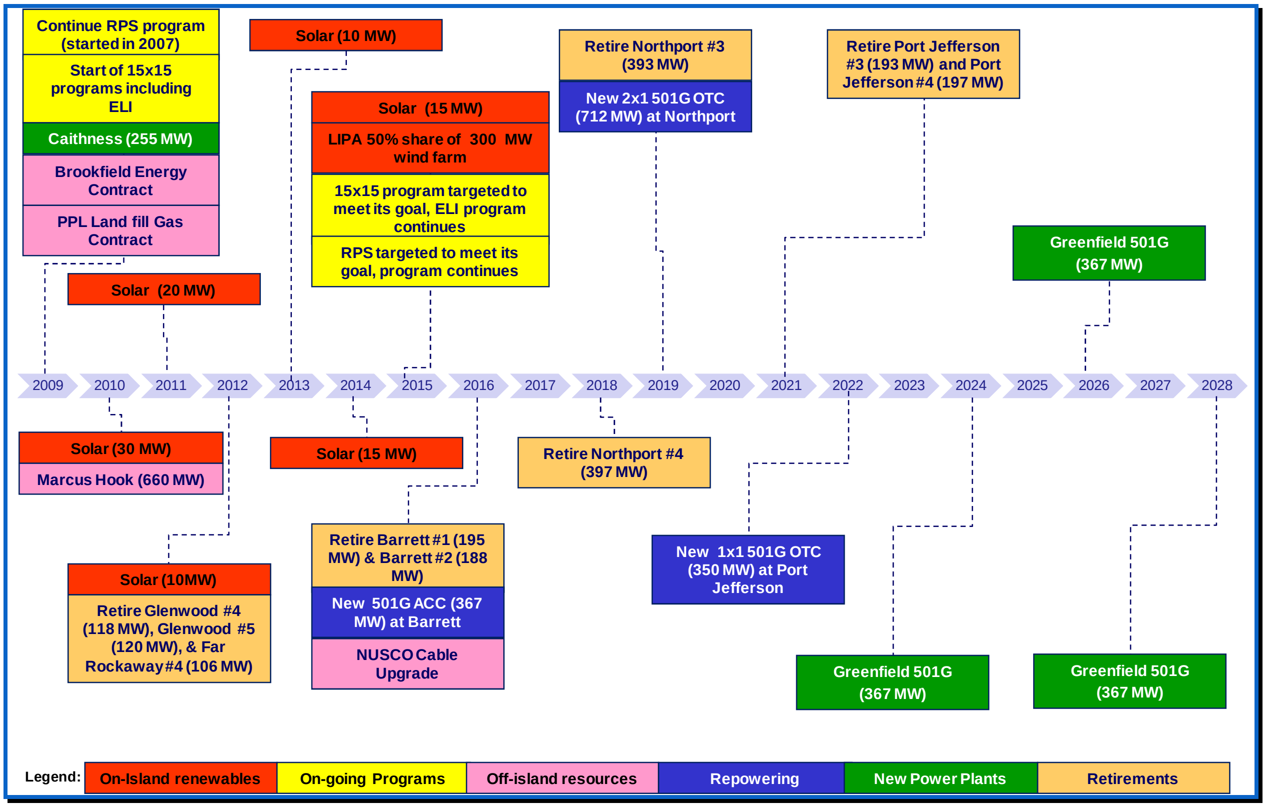


Exhibit 9-29 is a detailed rollout of the Representative Plan elements. The tactics are grouped under each of the strategies. Energy Efficiency describes the programs within the 15 x 15 strategy shows the projected annual energy savings from the cumulative effects of the entire 15 x 15 program. The Upgrade Fleet columns show the retirements, repowering, and new units. When a unit is repowered, the decommissioned units are shown under the retirement column and the new unit under the repower column. Under the Renewable Resources strategy, the Total RPS Energy column shows the annual RPS energy program deliveries from existing (Bear Swamp), approved (Brookfield Energy and PPL Landfill Gas), planned (First Solar RFP) and targeted resources (Second Solar RFP, offshore wind project, and future RPS RFPs and resources). Specific on-Island resources (including offshore resource connected directly to Long Island) are shown under the on-Island category. Unless specifically identified as on-Island, other future RPS resources that have not been procured yet have been assumed to come from off-Island sources. As the RPS program is implemented, some of the RPS energy may come from on-Island sources. The Improve Interconnection & Reliability Strategy shows both the new interconnections and off-Island contracts that are added to LIPA's portfolio. Approved off-Island contracts are shown under both the Renewable Resources and Improve Interconnections & Reliability strategies.

Exhibit 9-29 Representative Plan Implementation

Strategy	Energy Efficiency		Upgrade Fleet			Renewable Resources			Improve Interconnections & Reliability
Year	**Programs**	**Savings (GWH)**	**Repower (MW)**	**Retire (MW)**	**Greenfield Plants (MW)**	**Total RPS Energy (GWH)**	**On Island**	**Off Island**	**Resource / Upgrade (MW)**
2009	LIPA to implement its 15 x 15 plan: • Efficiency programs (e.g., ELI) • Generation efficiency • T&D efficiency • Smart Meters • Efficient Electro-Technologies New York State to implement its 15x15 plan: • Standards and Codes	237			Caithness (255 MW)	837		Brookfield Energy Hydro Contract PPL Landfill Gas Contract	
2010		240				1,205	Solar (30 MW)	LIPA to purchase RPS eligible renewable energy to meet its targets via bilateral purchases from upstate New York, PJM, and ISO-NE.	Marcus Hook (660 MW)
2011		365		Retire: • Glenwood 4 (118 MW) • Glenwood 5 (120 MW) • Far Rockaway 4 (106 MW)		1,548	Solar (20 MW)		
2012		593				1,959	Solar (10 MW)		
2013		610				2,294	Solar (10 MW)		
2014		597				2,559	Solar (15 MW)		
2015		448				2,987	Solar (15 MW) and 50% Share of new 300 MW Wind Farm (150 MW)		
2016		417	Barrett 501G ACC (367 MW)	Retire: • Barrett 1 (195 MW) • Barrett 2 (188 MW)		3,008			NUSCO Cable Upgrade
2017		409				3,032			
2018		394		Retire Northport 4 (397 MW)		2,975			
2019		347	Northport 2x1 501G OTC (712 MW)	Retire Northport 3 (393 MW)		3,069			
2020		276				3,217			
2021		178		Retire: • Port Jefferson 3 (193 MW) • Port Jefferson 4 (197 MW)		3,309			
2022		163	Port Jefferson 501G OTC (350 MW)			3,525			
2023		124				3,706			
2024		59			Green field 501g (367 MW)	3,895			
2025		37				4,156			
2026		(5)			Green field 501g (367 MW)	4,330			
2027		0				4,595			
2028		(8)			Green field 501g (367 MW)	4,866			

Storm Hardening Projects

2013 Contract Year Budget Plan
Status as of December 31, 2013

Project	WO Number	Description	WORK TYPE	STATUS	TOWN	CM LABOR	CM LABOR BURDEN	CM MATERIAL	CM SERVICES	CM OTHER	CM TOTAL	YTD LABOR	YTD LABOR BURDEN	YTD MATERIAL	YTD SERVICES	YTD OTHER	YTD WORK ORDER
Property																	
P_LIPA STORM HARDEN TRANS POLE																	
C049157	90000130084	Eastport 69-951, Storm Hardening	Conv	open		-233	-194	149	6,519	3,422	9,663	50,472	61,046	35,814	9,963	36,955	194,251
C049157	90000130085	North Bellport 69-849, Storm Hard	Conv	open		395	425	0	0	215	1,035	3,391	3,898	0	0	-146	7,143
		Sub-Total P_LIPA STORM HARDEN TRANS POLE				**162**	**231**	**149**	**6,519**	**3,637**	**10,698**	**53,863**	**64,944**	**35,814**	**9,963**	**36,809**	**201,394**
P_LIPA Storm Hardening Lines																	
CCN1220	1T101442195	W/S BELLMORE AVE, N BELLMORE	STMHA	CASBUILT	N BELLMORE	0	0	0	0	0	0	17,663	26,270	7,243	8,289	13,391	72,857
CCN1220	1T101442198	N/S MERRICK RD, SEAFORD	STMHA	CASBUILT	SEAFORD	0	0	0	0	0	0	13,529	19,857	7,308	2,056	8,179	50,929
CCN1220	1T101442209	P#789 JERICHO TPKE	STMHA	COMP	WOODBURY	8	7	0	677	373	1,065	13,562	8,750	10,523	677	3,988	37,500
CCN1220	1T101442284	P#832 JERICHO TPKE, SYOSSET	STMHA	COMP	SYOSSET	0	0	0	0	0	0	12,073	17,653	9,158	455	7,121	46,461
CCN1220	1T101442293	P#976 WHEATLEY RD, O WESTBURY	STMHA	COMP	O WESTBURY	0	0	0	3,708	2,019	5,727	15,758	22,612	6,965	7,290	12,131	64,756
CCN1220	1T101442302	P#408x JERUSALEM AVE, N BELLMORE	STMHA	COMP	N BELLMORE	0	0	0	8,966	4,881	13,847	10,885	16,203	6,938	10,015	11,615	55,656
CCN1220	1T101458649	SHELTER ROCK RD, MANHASSET	STMHA	CASBUILT	MANHASSET	0	0	0	0	0	0	14,512	9,650	5,777	675	2,804	33,418
CCN1220	1T101464998	P#7 OAK DR, PLAINVIEW	STMHA	CASBUILT	PLAINVIEW	53	44	0	0	29	126	5,226	3,378	3,645	0	1,050	13,298
CCN1220	1T101473727	P#7 10TH ST, ASU778, LOCUST VLY	STMHA	COMP	LOCUST VLY	0	0	0	0	0	0	1,602	1,161	308	0	769	3,840
CCN1220	1T101513863	2584 S ST MARKS AV	STMHA	COMP	BELLMORE	0	0	0	0	0	0	4,924	4,988	4,656	0	2,039	16,607
CCN1220	1T101516895	ASU 788 SUNSET RD, MASSAPEQUA	STMHA	COMP	MASSAPEQUA	0	0	0	0	0	0	1,507	2,155	1,789	0	1,159	6,610
CCN1220	1T101516896	ASU 789 NASSAU ST, MASSAPEQUA	STMHA	COMP	MASSAPEQUA	0	0	0	0	0	0	12,677	17,104	6,586	0	6,957	43,324
CCN1220	1T101516898	ASU 793 WILLIS AVE, MINEOLA	STMHA	CASBUILT	MINEOLA	0	0	0	20,753	11,298	32,052	1,461	2,107	2,487	20,753	12,038	38,846
CCN1220	1T101538350	2287 7TH ST	STMHA	COMP	E MEADOW	102	85	0	0	56	243	16,943	20,856	6,459	0	9,322	53,580
CCN1220	1T101539599	8 CARMANS RD	STMHA	COMP	FARMINGDALE	24	20	1,105	0	245	1,394	7,981	9,770	10,046	0	5,734	33,532
CCN1220	1T101541226	690 PLAINVIEW RD	STMHA	APPR	BETHPAGE	11	9	0	0	6	27	12,500	14,779	6,459	0	7,256	40,994
CCN1220	1T100791007	CARMANS RD, S FARMNGDLE	STMHC	COMP	S FARMNGDLE	0	0	0	677	368	1,045	1,364	1,734	1,833	677	1,305	6,913
CCN1220	1T101366853	4 SCUDDERS LN, GLEN HEAD	STMHC	CASBUILT	GLEN HEAD	0	0	0	0	0	0	474	603	1,175	0	583	2,835
CCN1220	1T101372777	4 LAKEVIEW DR, GREAT NECK	STMHC	COMP	GREAT NECK	0	0	0	2,776	1,511	4,287	0	0	1,503	2,776	1,992	6,271
CCN1220	1T101193976	LAKEVILLE RD, L SUCCESS	STMHR	COMP	L SUCCESS	0	0	0	0	0	0	2,898	2,215	2,283	24,692	12,750	44,838

Project	WO Number	Description	WORK TYPE	STATUS	TOWN	CM LABOR	CM LABOR BURDEN	CM MATERIAL	CM SERVICES	CM OTHER	CM TOTAL	YTD LABOR	YTD LABOR BURDEN	YTD MATERIAL	YTD SERVICES	YTD OTHER	YTD WORK ORDER
CCN1220	1T101343954	BAYVILLE RD, LOCUST VLY	STMHR	COMP	LOCUST VLY	0	0	0	44,861	24,422	69,284	168	214	2,038	48,540	26,929	77,889
CES1220	1T101450817	POLE #33 S/S EAST MAIN STREET	STMHA	COMP	RIVERHEAD	0	0	0	0	0	0	0	0	985	19,345	9,454	29,783
CES1220	1T101450822	POLE #86 E/S FLANDERS ROAD	STMHA	COMP	FLANDERS	0	0	0	18,464	10,052	28,516	572	371	711	18,464	10,328	30,446
CES1220	1T101450823	POLE #1132 E/S WASHINGTON AVE	STMHA	COMP	HOLTSVILLE	0	0	0	0	0	0	9,547	14,552	5,274	0	5,404	34,777
CES1220	1T101450825	POLE #71 S/O CANAL ROAD	STMHA	COMP	PT JEFFERSN	0	0	0	10,367	5,644	16,011	0	0	1,248	10,367	6,043	17,658
CES1220	1T101450830	POLE #2 S/S FORT POND BLVD.	STMHA	COMP	SPRINGS	0	0	0	0	0	0	0	0	5,827	24,507	13,442	43,775
CES1220	1T101450831	POLE #24 N/S WINDMILL LANE	STMHA	COMP	AMAGANSETT	0	0	0	0	0	0	0	0	1,834	677	906	3,417
CES1220	1T101450837	POLE #154 E/S NORTH SEA ROAD	STMHA	COMP	SOUTHAMPTON	0	0	0	0	0	0	0	0	571	0	149	720
CES1220	1T101450840	POLE #20.5 W/S DIVISION STREET	STMHA	COMP	SAG HARBOR	0	0	0	0	0	0	0	0	5,575	20,824	11,617	38,016
CES1220	1T101450844	POLE #185 W/S SOUTH FERRY ROAD	STMHA	COMP	SHELTER IS	0	0	0	14,695	8,000	22,694	0	0	3,566	14,695	9,141	27,401
CES1220	1T101483229	BARTON AVE, PATCHOGUE	STMHA	CASBUILT	PATCHOGUE	0	0	0	1,415	770	2,185	19,652	29,981	18,877	3,506	15,649	87,665
CES1220	1T101499433	THREE MILE HARBOR DR, E HAMPTON, ASU 1579	STMHA	COMP	E HAMPTON	0	0	0	25,251	13,746	38,997	0	0	2,942	28,760	15,459	47,161
CES1220	1T101319926	EDGAR AVE	STMHF	COMP	AQUEBOGUE	0	0	0	0	0	0	0	0	2,800	0	0	2,800
CES1220	1T101319938	EUGENE RD	STMHF	SCONST	CUTCHOGUE	0	0	0	0	0	0	0	0	0	1,499	708	2,207
CES1220	1T101335724	BARNES RD.	STMHH	COMP	MORICHES	0	0	0	0	0	0	0	0	6,086	-1,841	-830	3,414
CES1220	1T101335725	SILLS RD, PATCHOGUE	STMHH	FCOMPAD	PATCHOGUE	0	0	0	0	0	0	7,154	4,939	9,538	2,047	2,046	25,724
CES1220	1T101335726	LONG ISLAND EXPY.	STMHH	SCONST	MANORVILLE	1,065	996	0	0	580	2,641	96,018	75,977	131,012	10,988	24,542	338,537
CES1220	1T101335727	GATEWAY BLVD, PATCHOGUE	STMHH	FCOMPAD	PATCHOGUE	45	37	291	0	25	398	23,083	25,180	14,822	0	13,378	76,463
CES1220	1T101336720	119 West Av, Patchogue Pole #15 LBD 1902	STMHR	CASBUILT	PATCHOGUE	0	0	0	15,209	8,280	23,488	867	1,291	1,364	15,209	9,091	27,821
CES1220	1T101336723	S/O WOODS Rd, SHOREHAM P#620-5D- LBD 4954	STMHR	CASBUILT	SHOREHAM	0	0	0	0	0	0	0	0	0	23,167	14,364	37,531
CES1220	1T101336732	N/S MAIN RD, SOUTHOLD P#496 LBD 7203	STMHR	CASBUILT	SOUTHOLD	0	0	0	0	0	0	0	0	32,997	0	0	32,997
CES1220	1T101450953	LBD 5275, Pole # 20 AVE C, HOLBROOK	STMHR	SCONST	HOLBROOK	0	0	0	4,531	2,467	6,998	433	513	6,029	4,531	3,953	15,460
CES1220	1T101450956	LBD#7190, P#98 BRIDGE SAG HARBOR TPKE, BRIDGEHMPTN	STMHR	COMP	BRIDGEHMPTN	0	0	0	3,194	1,739	4,933	1,874	2,298	1,701	3,194	3,071	12,138
CES1220	1T101450959	LBD #7329, P#84BRIDGE SAG HARBOR TPKE, BRIDGEHMPTN	STMHR	COMP	BRIDGEHMPTN	0	0	0	15,530	8,455	23,985	2,643	3,655	7,453	15,530	12,008	41,289
CQN1220	90000128038	Valley Stream - LIRR Rectifier	Conv	open		0	0	0	0	0	0	926	920	0	0	574	2,421
CQN1220	T101358588	T101358588 FRANKLIN AVE, P6, F	Conv	Closed		0	0	0	0	0	0	0	0	0	-1,477	-916	-2,392
CQN1220	1T101084944	NEW HAVEN AVE, FAR ROCKWY	STMHA	PERREC	FAR ROCKWY	0	0	0	0	0	0	0	0	1,215	0	0	1,215
CQN1220	1T101440505	asu# 359, p# 27, MEACHAM AVE, ELMONT	STMHA	COMP	ELMONT	0	0	0	677	368	1,045	5,489	6,613	6,055	677	4,079	22,912

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CQN1220	1T101492574	BENRIS AVE, FRANKLIN SQ, ASU# 436	STMHA	CASBUILT	FRANKLIN SQ	0	0	0	0	0	0	5,992	8,757	4,065	0	3,399	22,213
CQN1220	1T101492593	LINDEN BLVD, ELMONT, ASU# 438	STMHA	FCOMPAD	ELMONT	5,816	4,823	13,092	12,520	12,276	48,527	8,531	8,275	16,197	18,540	17,575	69,118
CQN1220	1T101492597	HUNTER AVE, VALLEY STRM, ASU# 453	STMHA	CASBUILT	VALLEY STRM	0	0	0	0	0	0	7,497	11,160	4,151	0	4,159	26,966
CQN1220	1T101512155	ASU# 406, HEMPSTEAD TPKE, ELMONT	STMHA	SCONST	ELMONT	0	0	0	6,559	3,571	10,129	13,683	19,076	9,359	6,559	11,801	60,477
CQN1220	1T101512178	ASU # 491, N CORONA AVE, VALLEY STRM	STMHA	COMP	VALLEY STRM	0	0	0	2,948	1,605	4,553	942	1,198	3,202	2,948	2,715	11,005
CQN1220	1T101525804	ASU# 356, P# 11 ATLANTIC AVE, OCEANSIDE	STMHA	FCOMPAD	OCEANSIDE	0	0	216	0	45	261	960	1,136	6,942	0	1,966	11,005
CQN1220	1T101525815	ASU# 375, P# 13 DOGWOOD AVE, MALVERNE	STMHA	FCOMPAD	MALVERNE	0	0	2,452	0	351	2,803	0	0	6,795	0	1,263	8,058
CQN1220	1T101254732	74 ERICK AV	STMHC	CASBUILT	HEWLETT	0	0	0	0	0	0	0	0	0	630	390	1,020
CQN1220	1T101375579	HEALY AVE, P# 15, FAR ROCKWY	STMHC	CASBUILT	FAR ROCKWY	0	0	0	0	0	0	0	0	0	2,261	1,402	3,664
CQN1220	1T101375611	EAGLE AVE, P# 30, LAKEVIEW	STMHC	CASBUILT	LAKEVIEW	0	0	0	0	0	0	0	0	0	1,156	717	1,873
CQN1220	1T101375627	AUSTIN BLVD, P# 25, ISLAND PARK	STMHC	SCONST	ISLAND PARK	0	0	0	0	0	0	0	0	0	2,821	1,371	4,192
CQN1220	1T101375630	HEMPSTEAD TPKE, P# 239, W HEMPSTEAD	STMHC	CASBUILT	W HEMPSTEAD	0	0	0	0	0	0	515	654	235	0	251	1,655
CQN1220	1T101375977	WESTMINSTER RD, P#7, W HEMPSTEAD	STMHC	COMP	W HEMPSTEAD	0	0	0	0	0	0	0	0	353	5,487	2,755	8,595
CQN1220	1T101376148	HEMPSTEAD TPKE, P# 173, FRANKLIN SQ	STMHC	COMP	FRANKLIN SQ	0	0	0	0	0	0	3,735	4,417	2,310	0	2,277	12,739
CQN1220	1T101376180	GRAND AVE, P#59, BALDWIN	STMHC	SCONST	BALDWIN	0	0	0	0	0	0	0	0	0	374	232	606
CQN1220	1T101378652	P137.5 BROADWAY, WOODMERE	STMHC	APPR	WOODMERE	0	0	0	0	0	0	0	0	0	8,166	4,420	12,586
CQN1220	1T101378656	P207X-P213 HEMPSTEAD TPK, W HEMPSTEAD	STMHC	CASBUILT	W HEMPSTEAD	0	0	0	0	0	0	0	0	0	7,099	3,461	10,560
CQN1220	1T101378675	HEMPSTEAD TPKE, W HEMPSTEAD	STMHC	COMP	W HEMPSTEAD	0	0	0	1,289	702	1,991	21,000	29,591	10,828	4,767	13,648	79,834
CQN1220	1T101379551	P# 5 BEACH 219TH ST, ROCKWY PT	STMHC	CASBUILT	ROCKWY PT	0	0	0	0	0	0	0	0	0	1,441	692	2,133
CQN1220	1T101385185	320 BEACH 67TH ST	STMHC	COMP	ARVERNE	0	0	0	0	0	0	3,748	4,433	809	0	2,038	11,028
CQN1220	1T101385279	MAPLE AV	STMHC	APPR	CEDARHURST	0	0	0	0	0	0	0	0	0	701	435	1,136
CQN1220	1T101509643	WASHINGTON AVE, LAWRENCE	STMHC	COMP	LAWRENCE	0	0	28,212	0	0	28,212	673	838	32,821	0	1,290	35,622
CQN1220	1T101509655	OCEAN AVE, LAWRENCE	STMHC	COMP	LAWRENCE	0	0	0	0	0	0	0	0	1,635	0	343	1,978
CQN1220	1T101509660	BEACH 6TH ST, LAWRENCE	STMHC	APPR	LAWRENCE	0	0	0	0	0	0	1,030	1,485	1,252	0	718	4,485
CQN1220	1T101509663	HAWTHORNE ST, W HEMPSTEAD	STMHC	COMP	W HEMPSTEAD	0	0	0	0	0	0	1,835	2,333	1,325	0	1,068	6,561
CQN1220	1T101510164	S COTTAGE ST, VALLEY STRM	STMHC	COMP	VALLEY STRM	0	0	0	6,079	3,309	9,388	0	0	0	6,079	3,309	9,388
CQN1220	1T101510217	SUNRISE HWY, VALLEY STRM	STMHC	COMP	VALLEY STRM	0	0	0	4,580	2,493	7,073	0	0	824	4,580	2,666	8,070
CQN1220	1T101510457	PARK LN, VALLEY STRM	STMHC	COMP	VALLEY STRM	0	0	0	4,616	2,513	7,128	0	0	434	4,616	2,604	7,654

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CQN1220	1T101510459	RIVERDALE RD, VALLEY STRM	STMHC	COMP	VALLEY STRM	0	0	0	19,620	10,681	30,301	0	0	632	19,620	10,836	31,088
CQN1220	1T101510540	NEPTUNE AVE, WOODMERE, pole 5S(18575)	STMHC	COMP	WOODMERE	0	0	0	4,524	2,463	6,986	0	0	0	4,524	2,463	6,986
CQN1220	1T101510584	PENINSULA BLVD, WOODMERE, pole 77.5X	STMHC	CASBUILT	WOODMERE	0	0	13	1,903	1,036	2,951	3,791	5,467	2,022	1,903	2,980	16,162
CQN1220	1T101535596	1217 W BROADWAY, HEWLETT	STMHC	COMP	HEWLETT	0	0	0	0	0	0	1,390	1,768	700	0	679	4,536
CQN1220	1T101539296	235 MILL ST, LAWRENCE	STMHC	COMP	LAWRENCE	0	0	0	0	0	0	4,068	5,126	2,441	0	2,171	13,805
CQN1220	1T101539863	469 WOODBINE ST, UNIONDALE	STMHC	COMP	UNIONDALE	0	0	0	0	0	0	468	595	53	0	228	1,344
CQN1220	1T101540092	250 LINWOOD AVE, CEDARHURST	STMHC	COMP	CEDARHURST	0	0	0	0	0	0	0	0	653	0	137	790
CQN1220	1T101544633	69 SYCAMORE ST, W HEMPSTEAD	STMHC	COMP	W HEMPSTEAD	0	0	0	0	0	0	1,725	2,040	876	0	938	5,579
CQN1220	1T101549067	ROCKAWAY POINT BLVD, ROCKWY PT, pole 85x	STMHC	APPR	ROCKWY PT	2,523	2,093	1,295	0	1,598	7,508	2,523	2,093	1,295	0	1,598	7,508
CQN1220	1T101549368	264 HARRISON AVE, ISLAND PARK	STMHC	FCOMPAD	ISLAND PARK	1,596	1,324	893	0	869	4,683	1,596	1,324	893	0	869	4,683
CQN1220	1T101551505	OCEAN AVE, ROCKWY PT, pole 23	STMHC	FCOMPAD	ROCKWY PT	0	0	738	0	155	893	0	0	738	0	155	893
CQN1220	1T101554133	ROCKAWAY POINT BLVD, ROCKWY PT, pole 79S	STMHC	FCOMPAD	ROCKWY PT	76	63	23	0	46	208	76	63	23	0	46	208
CQN1220	1T101558428	LIDO BLVD, LIDO BCH, pole 53X	STMHC	APPR	LIDO BCH	0	0	1,494	0	90	1,585	0	0	1,494	0	90	1,585
CQN1220	1T101558511	5 REDAN RD, LIDO BCH, pole #3	STMHC	APPR	LIDO BCH	984	816	2,006	0	700	4,507	984	816	2,006	0	700	4,507
CQN1220	1T101145086	ROCKAWAY AVE, VALLEY STRM	STMHH	CASBUILT	VALLEY STRM	0	0	0	2,688	1,463	4,152	34,029	53,929	13,489	4,659	19,790	125,896
CQN1220	1T101338327	DNE, LYNBROOK, PROSPECT / LYNB. SW 5223	STMHH	APPR	LYNBROOK	0	0	0	0	0	0	0	0	19,504	0	0	19,504
CQN1220	1T100990132	P# 11.5 DNE, GARDEN CITY, LIRR R.O.W.	STMHR	INCONST	GARDEN CITY	0	0	637	0	134	770	0	0	637	0	134	770
CWS1220	1T101466491	MANATUCK BLVD, BAY SHORE	STMHA	CASBUILT	BAY SHORE	0	0	0	34,807	18,949	53,756	0	0	4,460	37,774	21,549	63,782
CWS1220	1T101466494	MILL POND RD, ST JAMES	STMHA	CASBUILT	ST JAMES	0	0	0	4,237	2,306	6,543	18,080	26,914	11,938	4,237	12,402	73,572
CWS1220	1T101466498	JULIA GOLDBACH AVE, RONKONKOMA	STMHA	CASBUILT	RONKONKOMA	0	0	0	2,030	1,105	3,135	8,875	6,161	6,644	5,801	6,332	33,812
CWS1220	1T101466524	MORICHES RD, ST JAMES	STMHA	COMP	ST JAMES	0	0	0	0	0	0	10,454	15,774	7,865	3,503	7,679	45,275
CWS1220	1T101466566	GLENNA LITTLE TRL, HUNTINGTON	STMHA	FCOMPAD	HUNTINGTON	0	0	0	2,030	1,105	3,135	14,082	18,613	6,052	2,030	8,688	49,466
CWS1220	1T101466578	BROWNS RD, HUNTINGTON	STMHA	CASBUILT	HUNTINGTON	0	0	0	1,885	1,026	2,911	6,157	9,165	2,987	1,885	4,046	24,240
CWS1220	1T100768254	CONKLIN ST, FARMINGDALE	STMHC	COMP	FARMINGDALE	0	0	0	677	368	1,045	3,101	3,942	1,922	677	1,976	11,617
CWS1220	1T101014455	LOWELL AVE, CNTRL ISLIP	STMHC	COMP	CNTRL ISLIP	0	0	0	0	0	0	1,492	1,897	1,528	0	933	5,850
CWS1220	1T101081087	HORIZON DR, HUNTINGTON	STMHC	COMP	HUNTINGTON	0	0	0	4,055	2,208	6,263	0	0	0	7,977	4,340	12,317
CWS1220	1T101081092	HORIZON DR, HUNTINGTON	STMHC	CASBUILT	HUNTINGTON	0	0	0	0	0	0	0	0	0	5,607	3,049	8,656
CWS1220	1T101082273	46TH ST, COPIAGUE	STMHC	COMP	COPIAGUE	0	0	0	0	0	0	1,037	1,319	1,175	0	638	4,168
CWS1220	1T101145362	N ALLEGHANY AVE, LINDENHURST	STMHC	COMP	LINDENHURST	0	0	0	0	0	0	2,159	2,744	1,943	0	1,232	8,078

Project	WO Number	Description	WORK TYPE	STATUS	TOWN	CM LABOR	CM LABOR BURDEN	CM MATERIAL	CM SERVICES	CM OTHER	CM TOTAL	YTD LABOR	YTD LABOR BURDEN	YTD MATERIAL	YTD SERVICES	YTD OTHER	YTD WORK ORDER
CWS1220	1T101249093	HARBOR RD, C SPRNG HBR	STMHC	COMP	C SPRNG HBR	0	0	0	0	0	0	0	0	10,688	0	3,420	14,109
CWS1220	1T101249155	5TH AVE, BAY SHORE	STMHC	SCONST	BAY SHORE	0	0	0	0	0	0	0	0	0	6,557	4,065	10,622
CWS1220	1T101250027	CHURCH ST, BAYPORT	STMHC	COMP	BAYPORT	0	0	0	0	0	0	4,322	5,494	1,992	0	2,109	13,917
CWS1220	1T101350167	P#9 VALLEYWOOD RD, COMMACK	STMHC	COMP	COMMACK	0	0	0	0	0	0	1,306	1,545	666	0	723	4,239
CWS1220	1T101350238	P#1 SHERWOOD AVE, FARMINGDALE	STMHC	COMP	FARMINGDALE	0	0	0	0	0	0	1,037	1,319	1,456	0	697	4,508
CWS1220	1T101357041	P#43 N MONROE AVE, LINDENHURST	STMHC	COMP	LINDENHURST	0	0	0	0	0	0	1,130	1,437	1,424	0	730	4,721
CWS1220	1T101359756	P#13 3RD ST, LINDENHURST	STMHC	COMP	LINDENHURST	0	0	0	0	0	0	2,673	3,399	2,183	0	1,536	9,791
CWS1220	1T101384675	P#16 PRIVATE RD, HUNT BAY, 10 LECLUSE LA	STMHC	COMP	HUNT BAY	0	0	0	1,154	628	1,782	0	0	437	1,154	720	2,311
CWS1220	1T101385337	P#1 KETCHAM AVE, ST JAMES	STMHC	COMP	ST JAMES	0	0	0	0	0	0	1,131	1,438	1,109	0	666	4,344
CWS1220	1T101385350	p#5 TANGLEWOOD DR, SMITHTOWN	STMHC	COMP	SMITHTOWN	0	0	0	0	0	0	0	0	545	0	115	660
CWS1220	1T101385356	P#8 HILLCREST DR, SMITHTOWN	STMHC	COMP	SMITHTOWN	0	0	0	0	0	0	1,386	1,639	376	0	754	4,155
CWS1220	1T101385397	P#17 BIRCHBROOK DR, SMITHTOWN	STMHC	COMP	SMITHTOWN	0	0	0	0	0	0	0	0	354	0	74	428
CWS1220	1T101385403	P#18 BIRCHBROOK DR, SMITHTOWN	STMHC	COMP	SMITHTOWN	0	0	0	0	0	0	0	0	730	0	153	883
CWS1220	1T101513511	P#1 BRETON AVE, MELVILLE	STMHC	COMP	MELVILLE	0	0	0	0	0	0	0	0	1,304	0	274	1,578
CWS1220	1T101513514	P#9.2 SYCAMORE ST, MELVILLE	STMHC	COMP	MELVILLE	0	0	0	0	0	0	3,397	4,017	1,102	0	1,853	10,369
CWS1220	1T101513517	P#6 GILFORD CT, MELVILLE	STMHC	COMP	MELVILLE	0	0	0	1,849	1,006	2,855	0	0	0	1,849	1,006	2,855
CWS1220	1T101513525	P#15A ALLENBY DR, NORTHPORT	STMHC	COMP	NORTHPORT	0	0	0	5,436	2,959	8,396	0	0	0	5,436	2,959	8,396
CWS1220	1T101513533	P#21-2 DNE, NORTHPORT, Northport Access Road	STMHC	COMP	NORTHPORT	0	0	0	2,686	1,462	4,149	0	0	1,005	2,686	1,674	5,365
CWS1220	1T101515663	P#72S WEST NECK RD, LLOYD HBR	STMHC	COMP	LLOYD HBR	0	0	0	0	0	0	0	0	186	0	39	225
CWS1220	1T101515689	32A FORT SALONGA RD, FT SALONGA	STMHC	COMP	FT SALONGA	0	0	0	4,604	2,506	7,110	0	0	0	4,604	2,506	7,110
CWS1220	1T101515713	P#2-2 E DEER PARK RD, DIX HILLS	STMHC	COMP	DIX HILLS	0	0	0	3,789	2,063	5,852	0	0	0	3,789	2,063	5,852
CWS1220	1T101515723	P#19A BONNIE DR, FT SALONGA	STMHC	COMP	FT SALONGA	0	0	0	5,380	2,929	8,308	0	0	0	5,380	2,929	8,308
CWS1220	1T101515726	P#978X JERICHO TPKE, HUNTINGTON	STMHC	COMP	HUNTINGTON	0	0	0	0	0	0	835	987	350	0	454	2,626
CWS1220	1T101515778	P#33S WEST NECK RD, HUNTINGTON	STMHC	COMP	HUNTINGTON	0	0	0	0	0	0	0	0	186	0	39	225
CWS1220	1T101329547	LBF#5344-P#55 LITTLE EAST NECK RD, BABYLON	STMHF	SCONST	BABYLON	0	0	18,105	135,871	77,770	231,747	4,949	7,136	45,190	144,877	93,280	295,433
CWS1220	1T101336247	OLD EAST NECK R HUNTINGTON, Long Island Expressway	STMHH	CASBUILT	HUNTINGTON	0	0	0	0	0	0	4,600	2,968	1,252	-369	235	8,686
CWS1220	1T101330190	LBD#1740-P#1-5 BRIDLE PATH RD, SMITHTOWN	STMHR	CASBUILT	SMITHTOWN	0	0	0	1,889	1,028	2,918	676	510	838	14,514	7,895	24,433
CWS1220	1T101330195	LBD#1741-P#18 NISSEQUOGUE RIVER RD, SMITHTOWN, Bly	STMHR	CASBUILT	SMITHTOWN	0	0	0	5,949	3,239	9,188	0	0	13,121	22,860	12,138	48,119

Project	WO Number	Description	WORK TYPE	STATUS	TOWN	CM LABOR	CM LABOR BURDEN	CM MATERIAL	CM SERVICES	CM OTHER	CM TOTAL	YTD LABOR	YTD LABOR BURDEN	YTD MATERIAL	YTD SERVICES	YTD OTHER	YTD WORK ORDER
CWS1220	1T101330197	LBD#4042-P#17 NISSEQUOGUE RIVER RD, SMITHTOWN, Bly	STMHR	CASBUILT	SMITHTOWN	0	0	0	3,911	2,129	6,040	1,562	1,139	4,123	33,531	18,593	58,948
CWS1220	1T101330207	LBD#4060-P#45 OLD INDIAN HEAD RD, KINGS PARK	STMHR	CASBUILT	KINGS PARK	0	0	0	0	0	0	669	485	2,091	5,979	3,852	13,075
		Sub-Total P LIPA Storm Hardening Lines				**12,305**	**10,317**	**70,573**	**481,313**	**276,222**	**850,730**	**551,864**	**654,962**	**663,875**	**772,828**	**705,965**	**3,349,493**
		Sub-Total Property				**12,467**	**10,548**	**70,722**	**487,832**	**279,859**	**861,428**	**605,727**	**719,906**	**699,689**	**782,791**	**742,774**	**3,550,887**
		Grand Total:				**12,467**	**10,548**	**70,722**	**487,832**	**279,859**	**861,428**	**605,727**	**719,906**	**699,689**	**782,791**	**742,774**	**3,550,887**

STORM HARDENING PLAN

Presentation to LIPA's Board

Operating Committee

Uniondale, NY

June 27, 2013

Overview

- Recent Events
  - Hurricanes Irene and Sandy refocused the need for review of the storm hardening program
  - Board request for review of and update on progress
  - Desire for consistency with current leading industry practices
  - Need for improved tracking of costs
- Updates
  - Storm Hardening Policy/Definition Effort
  - Damage Mitigation Plan and Funding

Proposed Changes

- Create clearer definition rather than general policy statement
- Overall **<u>Resiliency</u>** concept conforms to more recent industry parlance
- Concentrate on physical assets:
  - **Prevention** and **Survivability**
  - Include **Recovery** to expedite return of service, where Prevention and Survivability are not cost effective or feasible
  - Excludes "normal" utility investments (e.g., old breaker replacement)
  - Does not include conventional resource types of investment: generation or interconnections, but would include micro-grids
- Prospective identification of specific projects and incremental costs targeted to System Resiliency program
- References to separate Planning standards as well as design and cost assignments

Going Forward

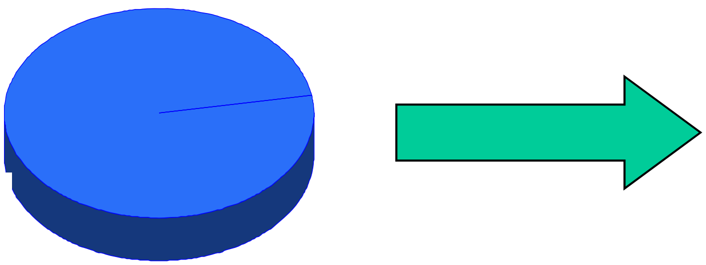
- Establish "Targeted" design criteria, examples,
  - Wind: 130 mph
  - Flooding: 1 in 500 years
- Trade-off between risk and costs
  - Not all equipment will be able to meet that target due to costs, locations, etc.
  - Develop alternatives including recovery options (i.e., water sensors to shut down, mobile transformers/generators)
- Evaluate tools to measure impact of program on storm performance
- Review and finalize
  - Cost allocations
  - Strategies
- Funding Levels and Time Frame to construct

LIPA's Storm Hardening Supplemented by FEMA/CDBG Funding

LIPA Plan

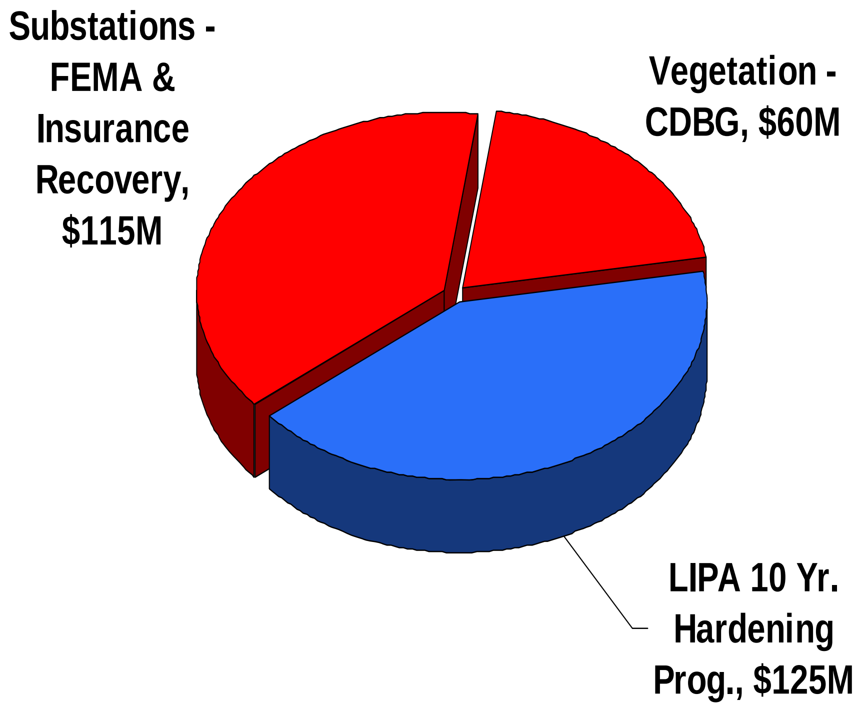
$500M over

20 Years



Currently in Year 7 of plan

$300M (Preliminary)



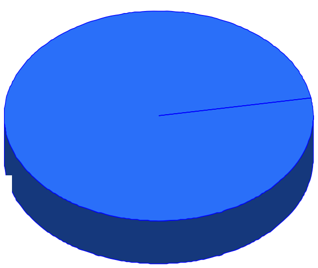
Based on 5 year program

Options for LIPA's Storm Hardening
Supplemented by FEMA/CDBG & Additional LIPA Funding

LIPA Plan

$500M over

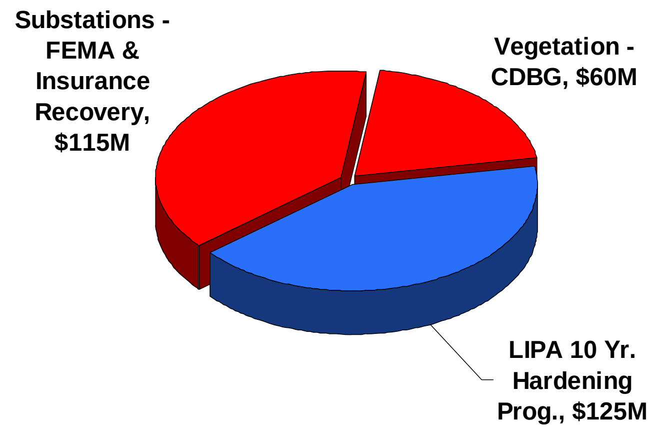
20 Years



Currently in Year 7 of plan

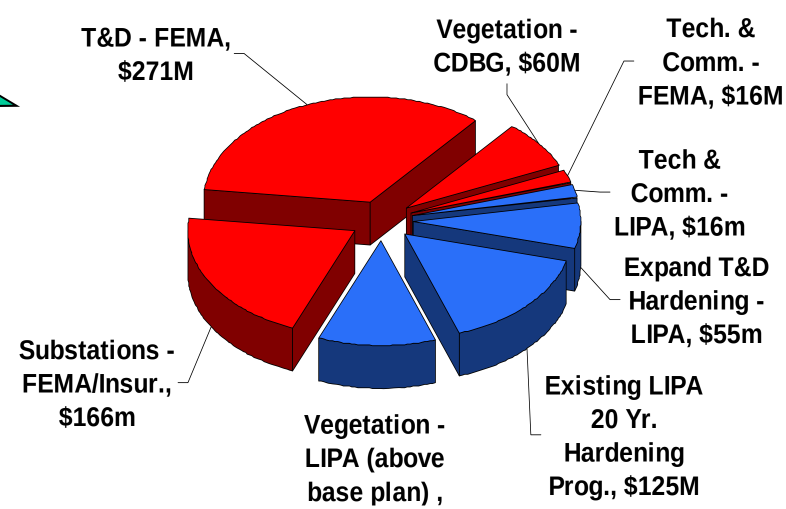
Expansion of existing $25M/year plan to a more aggressive program to address needs that came out of Sandy

$300M (Preliminary)



Based on 5 year program

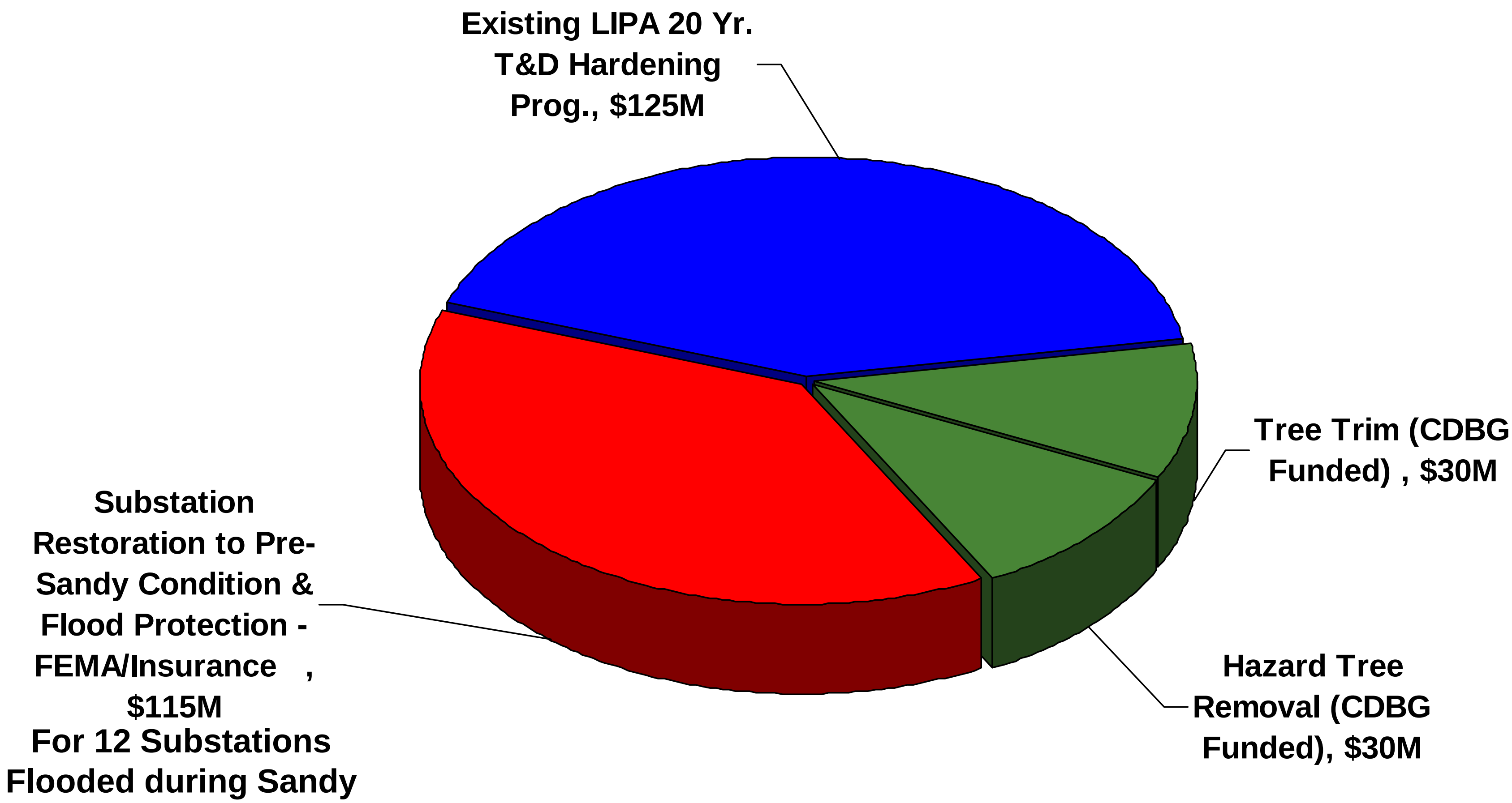
$800M (Preliminary)



LIPA
Long Island Power Authority

Storm Hardening Plan

$300M Plan With FEMA/CDBG & LIPA Funding

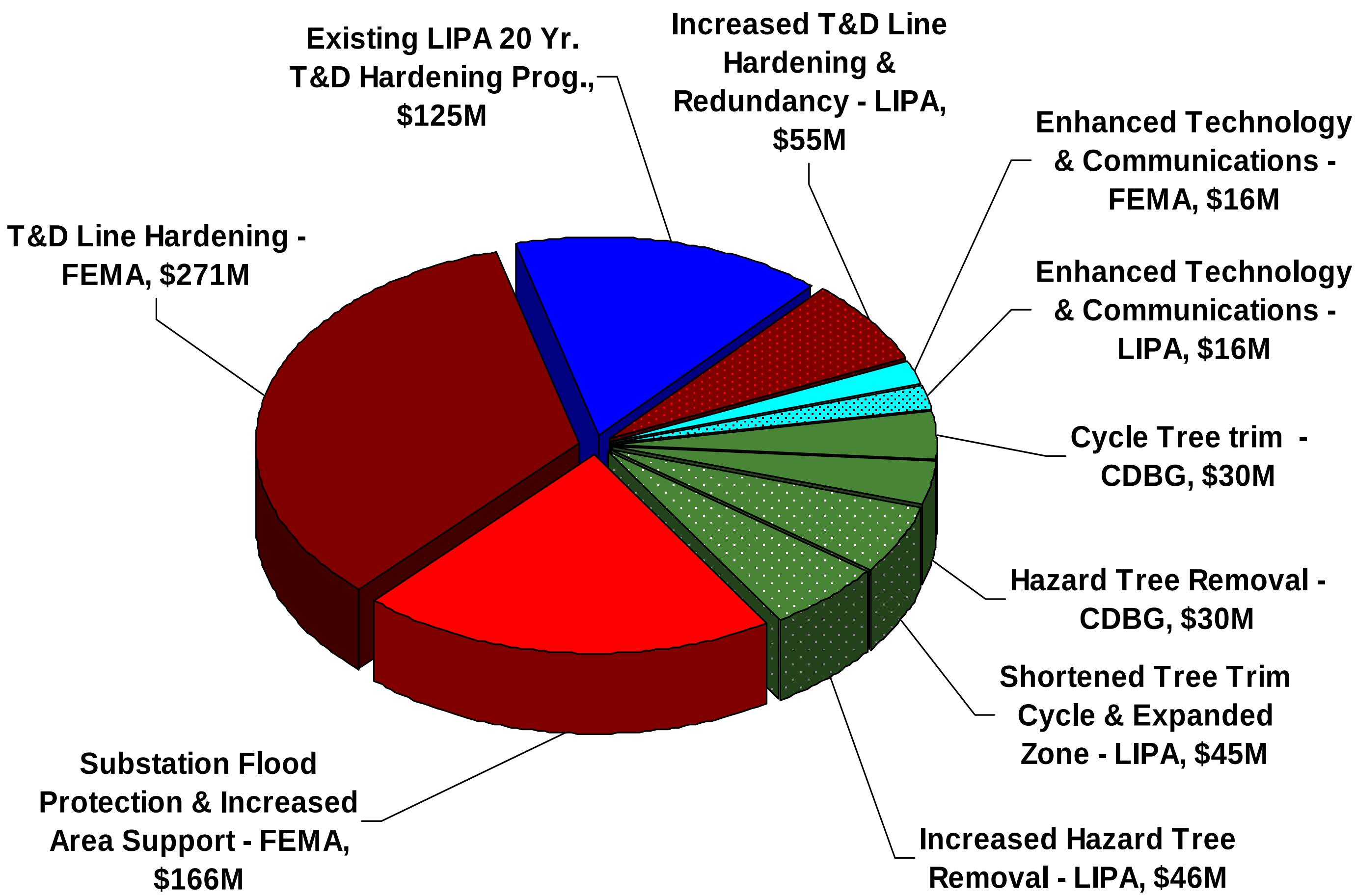


5 year program starting in 2014

Storm Hardening Plan
Increased Funding by FEMA/CDBG & LIPA

LIPA Long Island Power Authority

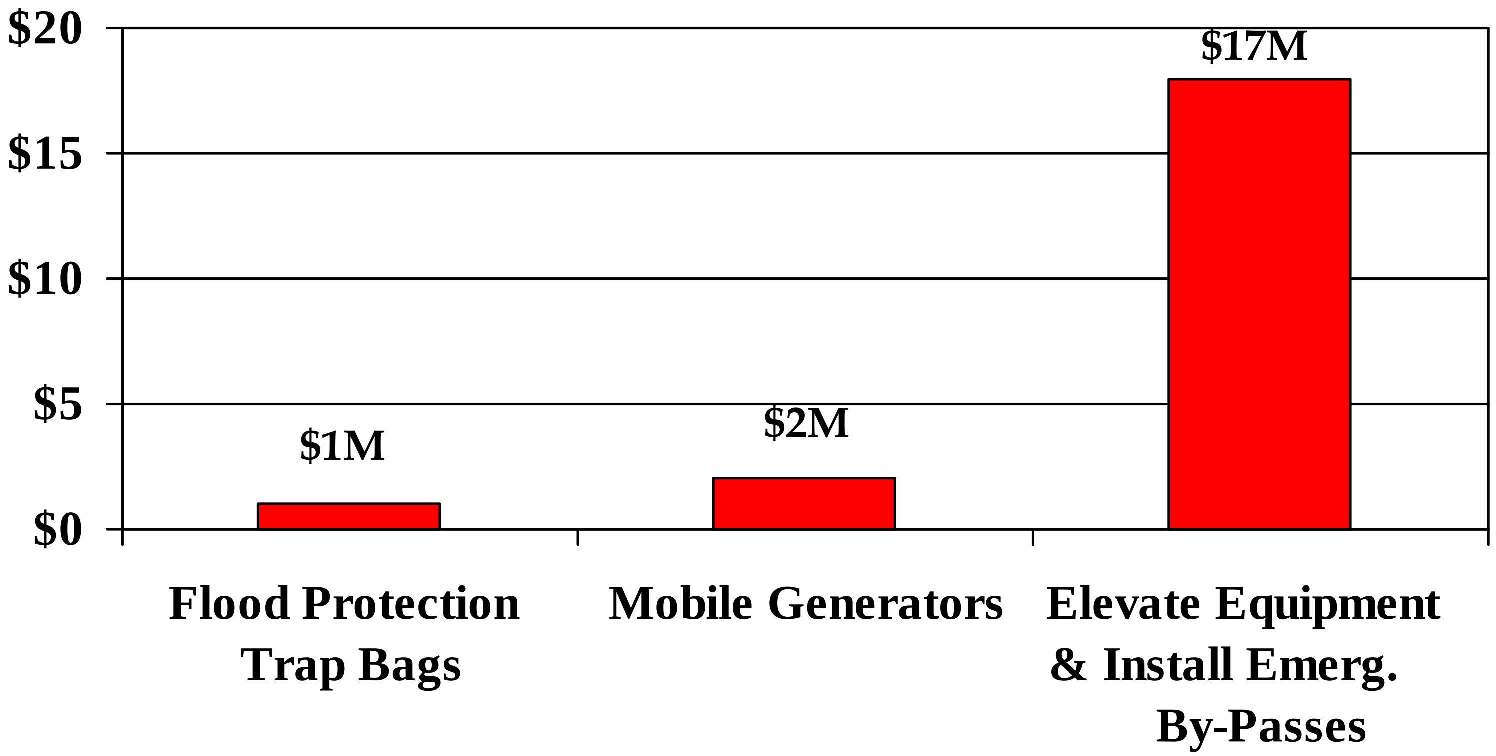
5 Year $800M LIPA/FEMA/CDBG Funding Plan



5 year program starting in 2014

Super Storm Sandy
2013 Substation Projects*

Temporary Repairs & Protective Measures (Approx. $20M)



*** Funding from FEMA & Insurance for Temporary Repairs & Protective Measures**

Costs are based on preliminary estimates

Storm Hardening Projects

2014 Contract Year Budget Plan
Status as of December 31, 2014

Project	WO Number	Description	WORK TYPE	STATUS	TOWN	CM LABOR	CM LABOR BURDEN	CM MATERIAL	CM SERVICES	CM OTHER	CM TOTAL	YTD LABOR	YTD LABOR BURDEN	YTD MATERIAL	YTD SERVICES	YTD OTHER	YTD WORK ORDER
Property																	
P_LIPA STORM HARDEN TRANS POLE																	
C049157	90000130084	Eastport 69-951, Storm Hardening	Conv	open		0	0	0	0	0	0	1,703	1,952	0	0	602	4,257
C049157	90000130085	North Bellport 69-849, Storm Hard	Conv	open		0	0	0	0	0	0	16,944	20,166	38,266	6,423	8,680	90,480
		Sub-Total P_LIPA STORM HARDEN TRANS POLE				**0**	**0**	**0**	**0**	**0**	**0**	**18,648**	**22,118**	**38,266**	**6,423**	**9,282**	**94,736**
P_LIPA Storm Hardening Lines																	
CCN1220	90000138769	N.Bellmore - Bellmore Substation	Conv	open		0	0	0	0	0	0	1,135	808	123	0	515	2,580
CCN1220	90000138771	Massapequa - Plainedge Subsation	Conv	open		0	0	0	0	0	0	2,507	1,636	104	0	1,140	5,387
CCN1220	90000138772	S.Farmingdale - Sterling Substation	Conv	open		0	0	0	0	0	0	202	128	136	0	92	558
CCN1220	1T101442198	N/S MERRICK RD, SEAFORD	STMHA	CASBUILT	SEAFORD	0	0	0	0	0	0	1,364	952	510	0	663	3,490
CCN1220	1T101568653	CARPENTER AVE, SEA CLIFF	STMHA	CASBUILT	SEA CLIFF	0	0	0	0	0	0	3,701	2,282	2,063	1,235	1,241	10,523
CCN1220	1T101568658	ALTAMONT AVE, SEA CLIFF	STMHA	CASBUILT	SEA CLIFF	0	0	0	0	0	0	3,550	2,188	1,826	1,789	1,709	11,061
CCN1220	1T101568664	JERUSALEM AVE, LEVITTOWN	STMHA	SCONST	LEVITTOWN	0	0	0	0	0	0	473	240	690	0	323	1,727
CCN1220	1T101568669	COUNTRY CLUB DR, MANHASSET	STMHA	CASBUILT	MANHASSET	0	0	0	0	0	0	1,946	1,200	1,078	679	1,191	6,094
CCN1220	1T101568683	MALLARD RD, LEVITTOWN	STMHA	CASBUILT	LEVITTOWN	0	0	0	0	0	0	3,166	1,603	1,422	934	1,518	8,644
CCN1220	1T101568687	MERRICK RD, MASSAPEQUA	STMHA	CASBUILT	MASSAPEQUA	0	0	0	0	0	0	4,170	2,112	1,495	0	1,538	9,314
CCN1220	1T101619376	460 BROADWAY, FIRE HSE	STMHA	CASBUILT	CARLE PLACE	0	0	0	0	0	0	3,166	3,782	3,155	0	1,042	11,145
CCN1220	1T101619404	389 NEW SOUTH RD	STMHA	CASBUILT	HICKSVILLE	0	0	0	0	0	0	2,981	3,561	1,991	0	633	9,166
CCN1220	1T101620140	91 LEE AV	STMHA	CASBUILT	HICKSVILLE	0	0	0	0	0	0	4,057	4,846	2,541	0	1,428	12,872
CCN1220	1T101621656	2 FLAX LA	STMHA	CASBUILT	LEVITTOWN	0	0	0	0	0	0	1,816	2,169	1,581	0	447	6,014
CCN1220	1T101621752	PLAINVIEW RD, ST LTG	STMHA	CASBUILT	BETHPAGE	0	0	0	0	0	0	2,458	2,936	1,868	1,869	1,298	10,428
CCN1220	1T101621793	14 SINGWORTH ST	STMHA	CASBUILT	OYSTER BAY	0	0	0	0	0	0	3,963	4,733	2,269	622	1,502	13,090
CCN1220	1T101627561	670 CONKLIN ST	STMHA	CASBUILT	FARMINGDALE	0	0	0	0	0	0	2,240	3,062	2,809	0	847	8,958
CCN1220	1T101628963	380 WOODBURY RD	STMHA	CASBUILT	HICKSVILLE	0	0	0	0	0	0	3,183	4,061	2,648	17,215	6,530	33,637
CCN1220	1T101629328	54 HAZELWOOD DR	STMHA	CASBUILT	JERICHO	0	0	0	0	0	0	3,704	4,425	1,508	0	1,111	10,748
CCN1220	1T101631453	417 N BROADWAY, STR 332	STMHA	CASBUILT	JERICHO	0	0	0	0	0	0	3,303	3,946	11,068	0	2,605	20,921

Project	WO Number	Description	WORK TYPE	STATUS	TOWN	CM LABOR	CM LABOR BURDEN	CM MATERIAL	CM SERVICES	CM OTHER	CM TOTAL	YTD LABOR	YTD LABOR BURDEN	YTD MATERIAL	YTD SERVICES	YTD OTHER	YTD WORK ORDER
CCN1220	1T101631626	1061 N BROADWAY	STMHA	CASBUILT	N MASSAPQUA	0	0	0	0	0	0	3,470	4,762	2,264	0	1,073	11,568
CCN1220	1T101651352	1220 BELLMORE RD	STMHA	APPR	BELLMORE	0	0	0	0	0	0	2,487	3,317	1,360	657	1,138	8,958
CCN1220	1T101653137	1438 BELLMORE AV	STMHA	CASBUILT	N BELLMORE	0	0	0	0	0	0	6,630	8,964	3,066	0	2,350	21,010
CCN1220	1T101663661	HEMPSTEAD TPKE, LEVITTOWN, P# 315 ASU 869	STMHA	CASBUILT	LEVITTOWN	0	0	497	0	48	546	2,942	3,751	2,322	0	1,236	10,252
CCN1220	1T101629510	15 ALLEN ST	STMHC	CASBUILT	NEW HYDE PK	0	0	0	0	0	0	1,679	2,005	883	0	571	5,139
CCN1220	1T101343954	BAYVILLE RD, LOCUST VLY	STMHR	CASBUILT	LOCUST VLY	0	0	0	0	0	0	0	0	0	850	396	1,246
CCN1220	1T101569396	ROCKLAND DR, JERICHO	STMHR	CASBUILT	JERICHO	0	0	0	0	0	0	2,230	1,375	5,427	38,865	13,521	61,418
CCN1220	1T101639884	465 LAKEVILLE RD, PUMP STA	STMHR	CASBUILT	L SUCCESS	0	0	0	0	0	0	12,075	16,940	24,382	100,581	51,737	205,716
CES1220	1T101450830	POLE #2 S/S FORT POND BLVD.	STMHA	CASBUILT	SPRINGS	0	0	0	0	0	0	0	0	0	4,314	2,029	6,343
CES1220	1T101450831	POLE #24 N/S WINDMILL LANE	STMHA	CASBUILT	AMAGANSETT	0	0	0	0	0	0	0	0	0	5,305	2,400	7,705
CES1220	1T101450837	POLE #154 E/S NORTH SEA ROAD	STMHA	CASBUILT	SOUTHAMPTON	0	0	0	0	0	0	0	0	0	5,142	2,394	7,535
CES1220	1T101450844	POLE #185 W/S SOUTH FERRY ROAD	STMHA	CASBUILT	SHELTER IS	0	0	0	0	0	0	0	0	0	8,070	3,651	11,720
CES1220	1T101555607	TWOMEY AVE, CALVERTON	STMHA	CASBUILT	CALVERTON	0	0	0	0	0	0	4,292	2,893	1,724	0	1,433	10,341
CES1220	1T101555627	PENNSYLVANIA AVE, ASU 4003	STMHA	CASBUILT	MEDFORD	0	0	0	0	0	0	3,674	3,910	9,476	623	3,037	20,720
CES1220	1T101555635	SWEEZEY ROAD	STMHA	CAN	CORAM	0	0	0	0	0	0	861	1,091	383	0	362	2,697
CES1220	1T101555645	Granny Rd	STMHA	CASBUILT	FARMNGVILLE	0	0	0	0	0	0	3,368	4,072	9,331	163	2,815	19,748
CES1220	1T101555650	MAIN RD, CUTCHOGUE	STMHA	CASBUILT	CUTCHOGUE	0	0	0	0	0	0	3,381	4,085	1,715	623	1,548	11,352
CES1220	1T101555660	STEPHAN HANDS PATH, E HAMPTON	STMHA	CASBUILT	E HAMPTON	0	0	0	0	0	0	575	687	890	882	624	3,658
CES1220	1T101555663	MONTAUK HWY, PATCHOGUE	STMHA	CASBUILT	PATCHOGUE	0	0	0	0	0	0	4,737	4,049	1,959	1,245	2,375	14,366
CES1220	1T101613748	PAT YAPHANK ROAD	STMHA	CASBUILT	YAPHANK	0	0	0	0	0	0	3,130	3,758	10,130	0	2,833	19,851
CES1220	1T101613752	FISH THICKET RD, PATCHOGUE	STMHA	CASBUILT	PATCHOGUE	70	99	0	0	62	231	3,342	4,008	9,538	0	2,762	19,650
CES1220	1T101613754	CHICHESTER AVENUE	STMHA	COMP	C MORICHES	0	0	0	0	0	0	0	0	537	8,139	11,588	20,264
CES1220	1T101613761	ROUTE 25	STMHA	CASBUILT	MIDDLE IS	70	99	0	0	62	231	4,160	4,984	9,839	339	3,108	22,430
CES1220	1T101614666	ROUTE 25	STMHA	CASBUILT	CORAM	0	0	0	0	0	0	4,542	5,878	2,541	0	1,523	14,484
CES1220	1T101614674	NORTH CNTRY ROAD	STMHA	COMP	ROCKY PT	0	0	0	0	0	0	0	0	686	13,200	12,988	26,874
CES1220	1T101614678	COUNTY ROAD 51, RIVERHEAD	STMHA	CASBUILT	RIVERHEAD	0	0	0	0	0	0	176	250	891	14,753	17,020	33,090
CES1220	1T101614679	MAIN ROAD	STMHA	CASBUILT	MATTITUCK	0	0	0	0	0	0	104	148	1,511	13,246	14,517	29,527
CES1220	1T101614684	HAWKINS AVE, LAKE RONK	STMHA	CASBUILT	LAKE RONK	0	0	0	0	0	0	3,260	4,454	2,382	311	1,390	11,797
CES1220	1T101617981	SAGAPONACK ROAD	STMHA	CASBUILT	SAGAPONACK	0	0	0	0	0	0	5,476	7,580	3,102	3,262	3,200	22,620

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CES1220	1T101617984	CEDAR STREET	STMHA	CASBUILT	E HAMPTON	0	0	0	0	0	0	4,327	6,085	1,239	651	1,298	13,601
CES1220	1T101617987	HANDS CREEK ROAD	STMHA	CASBUILT	E HAMPTON	0	0	0	0	0	0	3,181	4,346	2,977	0	817	11,320
CES1220	1T101617989	NOYACK ROAD	STMHA	CASBUILT	SOUTHAMPTON	0	0	0	5,122	0	5,122	4,220	5,978	1,820	6,774	1,886	20,678
CES1220	1T101617994	MONTAUK HWY.	STMHA	CASBUILT	E HAMPTON	0	0	0	0	0	0	3,418	4,842	1,694	649	1,345	11,948
CES1220	1T101650837	WAVERLY AVE, PATCHOGUE	STMHA	CASBUILT	PATCHOGUE	70	99	0	0	62	231	4,368	5,948	2,719	0	4,752	17,787
CES1220	1T101670695	LOCUST DR, ROCKY PT	STMHA	CASBUILT	ROCKY PT	0	0	0	0	0	0	0	0	1,007	0	211	1,218
CES1220	1T101335724	BARNES RD.	STMHH	CASBUILT	MORICHES	0	0	0	0	0	0	0	0	-2	0	0	-2
CES1220	1T101335726	LONG ISLAND EXPY.	STMHH	CASBUILT	MANORVILLE	0	0	0	0	0	0	7,671	4,777	1,461	0	2,585	16,493
CES1220	1T101450860	LIE SVC ROAD	STMHR	SCONST	HOLBROOK	0	0	0	0	0	0	3,104	2,167	922	0	1,509	7,702
CES1220	1T101450953	LBD 5275, Pole # 20 AVE C, HOLBROOK	STMHR	SCONST	HOLBROOK	0	0	0	0	0	0	3,258	2,275	686	0	1,585	7,804
CES1220	1T101450956	LBD#7190, P#98 BRIDGE SAG HARBOR TPKE, BRIDGEHMPTN	STMHR	CASBUILT	BRIDGEHMPTN	0	0	0	0	0	0	0	0	0	5,767	2,767	8,534
CES1220	1T101555651	ELECTRIC ST, PATCHOGUE	STMHR	SCONST	PATCHOGUE	778	1,103	176	0	1,155	3,212	778	1,103	176	0	1,155	3,212
CES1220	1T101555655	EASTWOOD BLVD, CENTEREACH	STMHR	SCONST	CENTEREACH	4,351	6,166	1,723	0	6,251	18,491	4,351	6,166	1,723	0	6,251	18,491
CES1220	1T101555659	MT SINAI CORAM ROAD	STMHR	CASBUILT	MT SINAI	0	0	0	0	0	0	6,639	9,408	2,263	0	9,361	27,671
CQN1220	1T101084944	NEW HAVEN AVE, FAR ROCKWY	STMHA	CASBUILT	FAR ROCKWY	0	0	0	0	0	0	0	0	1,866	23,659	25,652	51,177
CQN1220	1T101440505	asu# 359, p# 27, MEACHAM AVE, ELMONT	STMHA	CASBUILT	ELMONT	0	0	0	0	0	0	0	0	0	1,552	749	2,301
CQN1220	1T101492593	LINDEN BLVD, ELMONT, ASU# 438	STMHA	CASBUILT	ELMONT	0	0	0	0	0	0	0	0	7,781	1,557	2,366	11,704
CQN1220	1T101512178	ASU # 491, N CORONA AVE, VALLEY STRM	STMHA	CASBUILT	VALLEY STRM	0	0	0	0	0	0	0	0	0	27,030	13,579	40,609
CQN1220	1T101525804	ASU# 356, P# 11 ATLANTIC AVE, OCEANSIDE	STMHA	CASBUILT	OCEANSIDE	0	0	0	0	0	0	0	0	0	28,686	13,248	41,934
CQN1220	1T101525815	ASU# 375, P# 13 DOGWOOD AVE, MALVERNE	STMHA	CASBUILT	MALVERNE	0	0	0	0	0	0	0	0	0	41,691	20,004	61,695
CQN1220	1T101568139	W BROADWAY, WOODMERE	STMHA	CASBUILT	WOODMERE	0	0	0	0	0	0	1,372	740	994	11,222	5,764	20,092
CQN1220	1T101568147	FRONT ST, HEMPSTEAD	STMHA	CASBUILT	HEMPSTEAD	0	0	0	0	0	0	27,560	36,868	9,830	11,156	9,134	94,547
CQN1220	1T101568163	PENINSULA BLVD, HEMPSTEAD	STMHA	CASBUILT	HEMPSTEAD	0	0	0	0	0	0	9,317	12,732	4,070	2,608	3,025	31,752
CQN1220	1T101568165	UNIONDALE AVE, UNIONDALE	STMHA	CASBUILT	UNIONDALE	0	0	0	0	0	0	479	295	1,602	17,575	5,737	25,688
CQN1220	1T101568166	FORTESQUE AVE, OCEANSIDE	STMHA	CASBUILT	OCEANSIDE	0	0	0	0	0	0	1,324	833	962	11,473	5,802	20,394
CQN1220	1T101604103	185 W PARK AVE, LONG BCH	STMHA	CASBUILT	LONG BCH	0	0	0	0	0	0	2,773	2,729	3,800	35,935	12,110	57,346
CQN1220	1T101636678	180 DENTON AVE, LYNBROOK	STMHA	CASBUILT	LYNBROOK	0	0	0	0	0	0	5,980	8,172	2,483	0	1,973	18,608
CQN1220	1T101643045	OCEANSIDE RD, OCEANSIDE	STMHA	CASBUILT	OCEANSIDE	2,696	3,821	1,808	0	1,671	9,996	7,577	10,339	3,769	0	6,154	27,838

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CQN1220	1T101644450	3392 OCEANSIDE RD, OCEANSIDE	STMHA	COMP	OCEANSIDE	0	0	0	0	0	0	8,821	11,178	3,838	3,773	6,987	34,598
CQN1220	1T101644480	WINDSOR PKWY, OCEANSIDE	STMHA	CASBUILT	OCEANSIDE	2,921	4,223	810	0	2,215	10,169	4,441	6,378	1,832	668	5,432	18,751
CQN1220	1T101644504	DENTON AVE, E ROCKAWAY	STMHA	CASBUILT	E ROCKAWAY	0	0	0	0	0	0	1,230	1,742	402	17,058	17,035	37,467
CQN1220	1T101644548	YALE ST, HEMPSTEAD	STMHA	CASBUILT	HEMPSTEAD	0	0	0	0	0	0	5,743	7,277	2,483	0	2,197	17,700
CQN1220	1T101644560	ST PAULS PL, GARDEN CITY	STMHA	COMP	GARDEN CITY	0	0	0	9,612	8,464	18,076	0	0	1,318	27,399	20,631	49,347
CQN1220	1T101644879	WESTMINSTER RD, W HEMPSTEAD	STMHA	COMP	W HEMPSTEAD	0	0	0	0	0	0	4,637	6,176	1,488	1,623	2,973	16,897
CQN1220	1T101652379	p #22 GRAHAM ST, HEMPSTEAD	STMHA	SCONST	HEMPSTEAD	0	0	182	0	38	221	5,723	8,106	2,840	1,630	2,238	20,537
CQN1220	1T101049650	P#2 MAIN ST, E ROCKAWAY, W of Main&S/of Atlantic	STMHC	CASBUILT	E ROCKAWAY	0	0	0	0	0	0	0	0	0	3,673	1,102	4,775
CQN1220	1T101375627	AUSTIN BLVD, P# 25, ISLAND PARK	STMHC	CASBUILT	ISLAND PARK	0	0	0	0	0	0	2,257	2,696	1,807	5,094	2,403	14,257
CQN1220	1T101376148	HEMPSTEAD TPKE, P# 173, FRANKLIN SQ	STMHC	CASBUILT	FRANKLIN SQ	0	0	0	0	0	0	0	0	0	316	149	465
CQN1220	1T101376180	GRAND AVE, P#59, BALDWIN	STMHC	CASBUILT	BALDWIN	0	0	0	0	0	0	4,820	6,318	7,453	11,151	9,393	39,134
CQN1220	1T101378675	HEMPSTEAD TPKE, W HEMPSTEAD	STMHC	CASBUILT	W HEMPSTEAD	0	0	0	0	0	0	0	0	0	5,831	2,817	8,648
CQN1220	1T101385279	MAPLE AV	STMHC	COMP	CEDARHURST	0	0	0	0	0	0	10,245	13,259	3,684	1,443	5,006	33,636
CQN1220	1T101509643	WASHINGTON AVE, LAWRENCE	STMHC	CASBUILT	LAWRENCE	0	0	0	111	176	287	0	0	-14,106	17,992	9,006	12,891
CQN1220	1T101509655	OCEAN AVE, LAWRENCE	STMHC	CASBUILT	LAWRENCE	0	0	0	0	0	0	0	0	0	4,043	1,213	5,256
CQN1220	1T101540092	250 LINWOOD AVE, CEDARHURST	STMHC	CASBUILT	CEDARHURST	0	0	0	0	0	0	0	0	0	11,881	9,916	21,797
CQN1220	1T101548812	NEPTUNE WALK, ROCKWY PT, pole #3	STMHC	CASBUILT	ROCKWY PT	0	0	0	0	0	0	0	0	0	560	168	728
CQN1220	1T101549067	ROCKAWAY POINT BLVD, ROCKWY PT, pole 85x	STMHC	CASBUILT	ROCKWY PT	0	0	0	0	0	0	0	0	0	17,712	7,794	25,505
CQN1220	1T101551479	HILLCREST WALK, ROCKWY PT, pole #11	STMHC	CASBUILT	ROCKWY PT	0	0	0	0	0	0	0	0	0	5,646	2,710	8,356
CQN1220	1T101551505	OCEAN AVE, ROCKWY PT, pole 23	STMHC	CASBUILT	ROCKWY PT	0	0	0	0	0	0	0	0	3	6,070	2,913	8,986
CQN1220	1T101554133	ROCKAWAY POINT BLVD, ROCKWY PT, pole 79S	STMHC	CASBUILT	ROCKWY PT	0	0	0	0	0	0	0	0	0	1,535	461	1,996
CQN1220	1T101558428	LIDO BLVD, LIDO BCH, pole 53X	STMHC	CASBUILT	LIDO BCH	0	0	0	0	0	0	3,370	2,353	640	3,559	3,456	13,378
CQN1220	1T101558511	5 REDAN RD, LIDO BCH, pole #3	STMHC	CASBUILT	LIDO BCH	0	0	0	0	0	0	2,014	1,406	0	4,577	3,132	11,130
CQN1220	1T101602778	734 HARRISON ST, W HEMPSTEAD	STMHC	CASBUILT	W HEMPSTEAD	0	0	0	0	0	0	0	0	432	5,162	1,639	7,233
CQN1220	1T101606635	585 EUCLID AVE, W HEMPSTEAD	STMHC	CASBUILT	W HEMPSTEAD	0	0	0	0	0	0	1,733	1,068	927	0	389	4,117
CQN1220	1T101622878	414 LOCUST CT, LAKEVIEW	STMHC	CASBUILT	LAKEVIEW	0	0	0	0	0	0	3,458	4,131	1,756	0	825	10,170
CQN1220	1T101624173	2568 OVERLOOK PL, BALDWIN	STMHC	CASBUILT	BALDWIN	0	0	0	0	0	0	2,257	2,696	1,254	0	455	6,663
CQN1220	1T101624717	1080 LONG BEACH RD, S HEMPSTEAD	STMHC	CASBUILT	S HEMPSTEAD	0	0	0	0	0	0	876	1,046	879	1,786	880	5,467

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CQN1220	1T101627128	pole 3 CHERRY VALLEY RD, W HEMPSTEAD	STMHC	CASBUILT	W HEMPSTEAD	0	0	0	0	0	0	1,492	1,782	1,020	1,265	922	6,481
CQN1220	1T101628902	670 WILDWOOD RD, W HEMPSTEAD	STMHC	CASBUILT	W HEMPSTEAD	0	0	0	0	0	0	2,654	3,170	933	0	811	7,568
CQN1220	1T101629160	466 WOODBINE ST, UNIONDALE	STMHC	CAN	UNIONDALE	0	0	0	0	0	0	0	0	313	0	66	378
CQN1220	1T101629167	51 SEALY DR, LAWRENCE	STMHC	CASBUILT	LAWRENCE	0	0	0	0	0	0	1,129	1,348	940	0	421	3,838
CQN1220	1T101629181	CAUSEWAY, LAWRENCE	STMHC	CASBUILT	LAWRENCE	0	0	0	0	0	0	1,632	1,949	1,449	0	549	5,579
CQN1220	1T101630202	MAIN ST, E ROCKAWAY	STMHC	COMP	E ROCKAWAY	0	0	0	0	0	0	8,607	10,907	4,264	3,342	6,532	33,651
CQN1220	1T101631016	637 BEECH ST, LONG BCH	STMHC	CAN	LONG BCH	0	0	0	0	0	0	1,492	1,782	372	0	448	4,094
CQN1220	1T101631065	1042 BEECH ST, LONG BCH	STMHC	CASBUILT	LONG BCH	0	0	0	0	0	0	4,381	5,987	1,218	0	1,413	12,999
CQN1220	1T101631081	423 W MARKET ST, LONG BCH	STMHC	CASBUILT	LONG BCH	0	0	0	0	0	0	3,006	4,108	1,162	0	477	8,752
CQN1220	1T101631083	123 TAFT AVE, LONG BCH	STMHC	CASBUILT	LONG BCH	0	0	0	0	0	0	0	0	934	0	196	1,130
CQN1220	1T101631090	264 MAGNOLIA BLVD, LONG BCH	STMHC	CASBUILT	LONG BCH	0	0	0	0	0	0	2,878	3,933	2,224	0	1,093	10,129
CQN1220	1T101631867	100 CALIFORNIA ST, LONG BCH	STMHC	CASBUILT	LONG BCH	0	0	0	0	0	0	2,620	3,130	1,177	0	852	7,779
CQN1220	1T101636677	8 AUGUST WALK, LONG BCH	STMHC	CASBUILT	LONG BCH	0	0	0	0	0	0	0	0	0	1,164	349	1,513
CQN1220	1T101636688	11 BARNES ST, LONG BCH	STMHC	CASBUILT	LONG BCH	0	0	0	0	0	0	1,758	2,403	977	0	443	5,581
CQN1220	1T101662426	GRAND AVE, P#59, BALDWIN	STMHC	COMP	BALDWIN	0	0	0	1,262	0	1,262	2,112	2,800	995	1,995	0	7,902
CQN1220	1T101689159	DNE, HEWLETT, FEMA MITIGATION COSTS 2014	STMHC	APPR	HEWLETT	0	0	0	882,548	777,086	1,659,634	0	0	0	882,548	777,086	1,659,634
CQN1220	1T100990103	P# 637X W BROADWAY, HEWLETT	STMHR	CASBUILT	HEWLETT	0	0	0	0	0	0	748	379	1,425	15,744	7,944	26,240
CQN1220	1T100990132	P# 11.5 DNE, GARDEN CITY, LIRR R.O.W.	STMHR	COMP	GARDEN CITY	0	0	0	3,106	4,909	8,014	563	330	10,292	28,626	17,428	57,239
CWS1220	90000138900	P102.5&103 LIRR, N.Amityville	Conv	open		0	0	0	0	0	0	0	0	123	0	0	123
CWS1220	90000138902	P71&72 Ltle E Neck Rd W. Babylon	Conv	open		0	0	0	0	0	0	2,409	1,704	66	0	1,572	5,752
CWS1220	90000138903	P579 & P578 5th Ave, Bayshore	Conv	open		0	0	0	0	0	0	2,394	1,783	0	0	966	5,143
CWS1220	90000138904	P 230, P 231 Jefferson St, E Islip	Conv	open		0	0	0	0	0	0	5,160	2,823	40	0	2,375	10,398
CWS1220	1T101466524	MORICHES RD, ST JAMES	STMHA	CASBUILT	ST JAMES	0	0	0	0	0	0	0	0	0	3,342	1,003	4,344
CWS1220	1T101466566	GLENNA LITTLE TRL, HUNTINGTON	STMHA	CASBUILT	HUNTINGTON	0	0	0	0	0	0	0	0	0	1,243	584	1,827
CWS1220	1T101562688	P#18 S 4TH ST, BAY SHORE	STMHA	CASBUILT	BAY SHORE	0	0	0	0	0	0	0	0	11,327	9,495	5,227	26,049
CWS1220	1T101562701	P#159 LARKFIELD RD, E NORTHPORT	STMHA	CASBUILT	E NORTHPORT	0	0	0	0	0	0	4,260	2,269	2,946	1,155	2,828	13,459
CWS1220	1T101562893	P#52 4TH AVE, BAY SHORE	STMHA	CASBUILT	BAY SHORE	128	181	0	0	113	422	4,930	5,917	2,911	1,869	2,040	17,665
CWS1220	1T101592261	P#1262 ROUTE 25A, CENTERPORT	STMHA	CASBUILT	CENTERPORT	0	0	0	0	0	0	3,336	4,614	2,250	2,280	1,968	14,447
CWS1220	1T101592268	P#55 WILSON BLVD, CNTRL ISLIP	STMHA	CASBUILT	CNTRL ISLIP	0	0	0	0	0	0	8,099	9,674	3,595	0	1,953	23,320

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CWS1220	1T101592330	P#1 CRESCENT BEACH DR, HUNTINGTON	STMHA	CASBUILT	HUNTINGTON	0	0	0	0	0	0	5,348	3,297	10,681	0	3,510	22,835
CWS1220	1T101592379	P#25 PARK AVE, HUNTINGTON	STMHA	CASBUILT	HUNTINGTON	0	0	0	0	0	0	3,222	1,986	1,375	0	1,077	7,659
CWS1220	1T101592488	P#234 TOWNLINE RD, E NORTHPORT	STMHA	CASBUILT	E NORTHPORT	0	0	0	0	0	0	4,782	2,948	2,051	4,551	2,997	17,329
CWS1220	1T101592574	P#48 E 17TH ST, HUNT STA	STMHA	CASBUILT	HUNT STA	0	0	0	0	0	0	8,071	7,162	3,286	5,763	3,135	27,418
CWS1220	1T101605395	ASU 1075-P#40 WEST HILLS RD, HUNT STA	STMHA	CASBUILT	HUNT STA	0	0	0	0	0	0	0	0	989	7,963	2,596	11,548
CWS1220	1T101605412	ASU1037-P#1165 E MAIN ST, HUNTINGTON	STMHA	CASBUILT	HUNTINGTON	0	0	0	0	0	0	6,506	8,890	2,102	1,924	2,615	22,037
CWS1220	1T101605419	ASU1041-P#37 HUNTINGTON BAY RD, HUNTINGTON, Young	STMHA	CASBUILT	HUNTINGTON	0	0	0	0	0	0	5,571	5,213	1,485	0	1,671	13,941
CWS1220	1T101605435	ASU1151-P#170.5 NEW YORK AVE, HUNTINGTON	STMHA	CAN	HUNTINGTON	0	0	0	0	0	0	-64	-323	122	0	6	-258
CWS1220	1T101605437	ASU3009-P#10 SOUNDVIEW DR, HUNTINGTON	STMHA	CASBUILT	HUNTINGTON	0	0	0	0	0	0	4,847	5,808	1,570	2,233	2,143	16,601
CWS1220	1T101605440	ASU3010-P#21 MAPLEWOOD RD, HUNTINGTON, Lodge Ave	STMHA	CASBUILT	HUNTINGTON	0	0	0	0	0	0	0	0	1,891	8,575	2,970	13,436
CWS1220	1T101639819	P#100 ROUTE 110, AMITYVILLE	STMHA	COMP	AMITYVILLE	0	0	0	0	0	0	517	655	1,860	2,008	1,451	6,492
CWS1220	1T101639839	DIXON AVE, AMITYVILLE	STMHA	SCONST	AMITYVILLE	158	308	509	0	371	1,346	158	308	509	0	371	1,346
CWS1220	1T101639863	P#2 RITTER AVE, AMITYVILLE	STMHA	COMP	AMITYVILLE	0	0	0	0	0	0	0	0	1,441	790	635	2,866
CWS1220	1T101639864	P#7 BEECHWOOD DR, W BABYLON	STMHA	SCONST	W BABYLON	1,045	1,481	756	0	1,733	5,015	1,045	1,481	1,148	0	1,816	5,489
CWS1220	1T101639868	P#32 CLINTON AVE, BAY SHORE	STMHA	CASBUILT	BAY SHORE	0	0	0	0	0	0	3,313	4,693	3,135	1,361	1,241	13,744
CWS1220	1T101639869	P#53 PINEAIRE DR, BAY SHORE	STMHA	SCONST	BAY SHORE	0	0	509	0	107	616	0	0	509	0	107	616
CWS1220	1T101639879	P#34 MANATUCK BLVD, BAY SHORE	STMHA	CAN	BAY SHORE	0	0	0	0	0	0	1,109	1,571	1,465	0	59	4,204
CWS1220	1T101657564	GREAT NECK RD, COPIAGUE	STMHA	SCONST	COPIAGUE	317	616	0	0	527	1,461	317	616	0	0	527	1,461
CWS1220	1T101657579	45TH ST, COPIAGUE	STMHA	CASBUILT	COPIAGUE	171	242	0	0	150	563	4,265	6,043	4,001	0	6,385	20,693
CWS1220	1T101657585	MONTAUK HWY, LINDENHURST	STMHA	CASBUILT	LINDENHURST	6,593	9,343	1,745	0	9,387	27,067	6,593	9,343	1,745	0	9,387	27,067
CWS1220	1T101249093	HARBOR RD, C SPRNG HBR	STMHC	CASBUILT	C SPRNG HBR	0	0	0	0	0	0	0	0	0	11,474	5,328	16,802
CWS1220	1T101250027	CHURCH ST, BAYPORT	STMHC	CASBUILT	BAYPORT	0	0	0	0	0	0	0	0	0	684	319	1,003
CWS1220	1T101262742	P#72 SHORE RD E, HUNTINGTON	STMHC	CASBUILT	HUNTINGTON	0	0	0	0	0	0	4,813	6,818	1,190	2,574	2,525	17,920
CWS1220	1T101350167	P#9 VALLEYWOOD RD, COMMACK	STMHC	CASBUILT	COMMACK	0	0	0	0	0	0	8	5	0	0	4	17
CWS1220	1T101384675	P#16 PRIVATE RD, HUNT BAY, 10 LECLUSE LA	STMHC	CASBUILT	HUNT BAY	0	0	0	0	0	0	0	0	0	9,788	4,557	14,345
CWS1220	1T101385337	P#1 KETCHAM AVE, ST JAMES	STMHC	CASBUILT	ST JAMES	0	0	0	0	0	0	0	0	0	1,771	830	2,600
CWS1220	1T101385350	p#5 TANGLEWOOD DR, SMITHTOWN	STMHC	CASBUILT	SMITHTOWN	0	0	0	0	0	0	0	0	0	11,325	5,273	16,597
CWS1220	1T101385356	P#8 HILLCREST DR, SMITHTOWN	STMHC	CASBUILT	SMITHTOWN	0	0	0	0	0	0	8	5	0	0	4	17

Project	WO Number	Description	WORK TYPE	STATUS	TOWN	CM LABOR	CM LABOR BURDEN	CM MATERIAL	CM SERVICES	CM OTHER	CM TOTAL	YTD LABOR	YTD LABOR BURDEN	YTD MATERIAL	YTD SERVICES	YTD OTHER	YTD WORK ORDER
CWS1220	1T101385397	P#17 BIRCHBROOK DR, SMITHTOWN	STMHC	CASBUILT	SMITHTOWN	0	0	0	0	0	0	0	0	0	3,696	1,721	5,417
CWS1220	1T101385403	P#18 BIRCHBROOK DR, SMITHTOWN	STMHC	CASBUILT	SMITHTOWN	0	0	0	0	0	0	0	0	0	2,424	1,128	3,552
CWS1220	1T101513511	P#1 BRETON AVE, MELVILLE	STMHC	CASBUILT	MELVILLE	0	0	0	0	0	0	0	0	0	5,929	2,761	8,690
CWS1220	1T101513514	P#9.2 SYCAMORE ST, MELVILLE	STMHC	CASBUILT	MELVILLE	0	0	0	0	0	0	8	5	0	0	4	17
CWS1220	1T101513517	P#6 GILFORD CT, MELVILLE	STMHC	CASBUILT	MELVILLE	0	0	0	0	0	0	0	0	0	8,339	4,024	12,362
CWS1220	1T101515661	P#7.1 EAST GATE RD, LLOYD HBR	STMHC	CASBUILT	LLOYD HBR	0	0	0	0	0	0	0	0	798	4,326	1,465	6,589
CWS1220	1T101515663	P#72S WEST NECK RD, LLOYD HBR	STMHC	CASBUILT	LLOYD HBR	0	0	0	0	0	0	0	0	0	2,473	1,202	3,675
CWS1220	1T101515686	P84S DNE, FT SALONGA, Greenlawn Ave	STMHC	CASBUILT	FT SALONGA	0	0	0	0	0	0	0	0	0	1,954	586	2,541
CWS1220	1T101515778	P#33S WEST NECK RD, HUNTINGTON	STMHC	CASBUILT	HUNTINGTON	0	0	0	0	0	0	0	0	0	1,879	914	2,793
CWS1220	1T101603726	P#13 ARLINGTON AVE, WYANDANCH	STMHC	CASBUILT	WYANDANCH	0	0	0	0	0	0	1,807	2,180	1,015	0	624	5,626
CWS1220	1T101603734	P#18 BOOKER AVE, WYANDANCH	STMHC	COMP	WYANDANCH	0	0	0	2,749	2,420	5,169	0	0	392	2,749	2,502	5,643
CWS1220	1T101603738	P#5 MCELROY ST, WEST ISLIP	STMHC	CASBUILT	WEST ISLIP	0	0	0	0	0	0	1,383	1,652	912	0	497	4,445
CWS1220	1T101603744	P#14 W 5TH ST, WEST ISLIP	STMHC	CASBUILT	WEST ISLIP	0	0	0	0	0	0	0	0	391	1,603	563	2,556
CWS1220	1T101603749	P#1 MONROE ST, S FARMNGDLE	STMHC	CASBUILT	S FARMNGDLE	0	0	0	0	0	0	0	0	1,273	2,140	909	4,322
CWS1220	1T101603752	P#9 HILLTOP AVE, W BABYLON	STMHC	CAN	W BABYLON	0	0	0	0	0	0	1,624	2,058	1,972	0	1,028	6,682
CWS1220	1T101603762	1678A MONTAUK HWY, ISLIP	STMHC	CASBUILT	ISLIP	0	0	0	0	0	0	1,109	1,571	1,203	652	746	5,281
CWS1220	1T101603774	p#14 CHAMPLIN AVE, E ISLIP	STMHC	COMP	E ISLIP	0	0	0	0	0	0	1,109	1,571	913	0	249	3,841
CWS1220	1T101610759	P#79A GIBBS POND RD, NESCONSET	STMHC	CASBUILT	NESCONSET	0	0	0	0	0	0	1,595	2,180	797	0	399	4,971
CWS1220	1T101610763	P#79B GIBBS POND RD, NESCONSET	STMHC	CASBUILT	NESCONSET	0	0	0	0	0	0	532	727	3,062	0	671	4,992
CWS1220	1T101610765	P#79C GIBBS POND RD, NESCONSET	STMHC	CASBUILT	NESCONSET	0	0	0	0	0	0	1,064	1,453	708	0	358	3,584
CWS1220	1T101610778	P#16S CAMBON AVE, ST JAMES	STMHC	CASBUILT	ST JAMES	0	0	0	0	0	0	3,301	4,676	1,120	1,304	1,275	11,675
CWS1220	1T101610781	P#9 PLAISTED AVE, SMITHTOWN	STMHC	COMP	SMITHTOWN	0	0	0	0	0	0	1,109	1,571	814	0	228	3,722
CWS1220	1T101610786	P#18 MOBREY LN, SMITHTOWN	STMHC	COMP	SMITHTOWN	0	0	0	0	0	0	714	905	672	0	427	2,719
CWS1220	1T101610805	P#12S WASHINGTON AVE, BRENTWOOD	STMHC	CASBUILT	BRENTWOOD	0	0	0	0	0	0	2,491	3,529	896	652	1,016	8,584
CWS1220	1T101610811	P#2 SMITH ST, CNTRL ISLIP	STMHC	CASBUILT	CNTRL ISLIP	0	0	0	0	0	0	1,922	2,722	890	0	628	6,162
CWS1220	1T101610816	P#7X GLENMORE AVE, CNTRL ISLIP	STMHC	CASBUILT	CNTRL ISLIP	0	0	0	0	0	0	1,462	1,998	646	0	439	4,546
CWS1220	1T101610822	P#47S N COUNTRY RD, SMITHTOWN	STMHC	COMP	SMITHTOWN	0	0	0	0	0	0	1,060	1,344	832	651	562	4,449
CWS1220	1T101610827	P#73A MIDDLE COUNTRY RD, SMITHTOWN	STMHC	COMP	SMITHTOWN	0	0	0	0	0	0	1,159	1,469	1,431	0	407	4,467
CWS1220	1T101610842	P#1 ROSALIA CT, SMITHTOWN	STMHC	CASBUILT	SMITHTOWN	0	0	0	0	0	0	2,931	4,152	2,100	0	919	10,103

Project	WO Number	Description	WORK TYPE	STATUS	TOWN	CM LABOR	CM LABOR BURDEN	CM MATERIAL	CM SERVICES	CM OTHER	CM TOTAL	YTD LABOR	YTD LABOR BURDEN	YTD MATERIAL	YTD SERVICES	YTD OTHER	YTD WORK ORDER
CWS1220	1T101610848	P#2 NORTH AVE, SMITHTOWN	STMHC	CASBUILT	SMITHTOWN	0	0	0	0	0	0	1,109	1,571	867	0	401	3,948
CWS1220	1T101611083	P#1726X S COUNTRY RD, E ISLIP	STMHC	CASBUILT	E ISLIP	0	0	0	0	0	0	1,064	1,453	1,009	651	457	4,635
CWS1220	1T101611088	P#1 FREEMAN AVE, ISLIP	STMHC	CASBUILT	ISLIP	0	0	0	0	0	0	1,857	2,631	811	0	639	5,939
CWS1220	1T101611089	P#3 BROOK CIR, ISLIP TERR	STMHC	CASBUILT	ISLIP TERR	0	0	0	0	0	0	2,101	2,872	1,238	0	696	6,907
CWS1220	1T101611141	P#22P.5 WENDOVER RD, SAYVILLE	STMHC	CASBUILT	SAYVILLE	0	0	0	0	0	0	1,064	1,453	736	0	401	3,654
CWS1220	1T101620159	P#22X UNION BLVD, E ISLIP	STMHC	CASBUILT	E ISLIP	0	0	0	0	0	0	1,842	2,609	1,319	0	463	6,233
CWS1220	1T101620181	P#171A SUNKEN MEADOW RD, KINGS PARK	STMHC	CASBUILT	KINGS PARK	0	0	0	0	0	0	0	0	511	0	107	619
CWS1220	1T101620191	P#1034A RAILROAD AVE, RONKONKOMA	STMHC	CASBUILT	RONKONKOMA	0	0	0	0	0	0	1,109	1,571	778	0	218	3,675
CWS1220	1T101621173	P#17 SHEP JONES LN, ST JAMES	STMHC	CASBUILT	ST JAMES	0	0	0	0	0	0	0	0	0	651	195	847
CWS1220	1T101621280	P#28X ROUTE 109, W BABYLON	STMHC	CASBUILT	W BABYLON	0	0	0	0	0	0	536	640	1,144	6,783	2,436	11,539
CWS1220	1T101621289	P#4 NORTON AVE, W BABYLON	STMHC	CASBUILT	W BABYLON	0	0	0	0	0	0	0	0	391	2,731	901	4,023
CWS1220	1T101621335	P#25B SUNRISE HWY, W BABYLON	STMHC	CASBUILT	W BABYLON	0	0	0	0	0	0	1,064	1,453	940	0	401	3,859
CWS1220	1T101621380	P#8A EADS ST, W BABYLON	STMHC	CASBUILT	W BABYLON	0	0	0	0	0	0	565	772	341	0	187	1,865
CWS1220	1T101659576	P#205S SUNKEN MEADOW RD, KINGS PARK	STMHC	COMP	KINGS PARK	0	0	0	0	0	0	1,060	1,344	521	0	445	3,370
CWS1220	1T101329547	LBF#5344-P#55 LITTLE EAST NECK RD, BABYLON	STMHF	CASBUILT	BABYLON	0	0	0	0	0	0	0	0	892	89,167	40,904	130,963
CWS1220	1T101572291	P#65-P#66 MANATUCK BLVD, BAY SHORE	STMHH	CASBUILT	BAY SHORE	0	0	0	0	0	0	16,057	21,009	409	0	5,169	42,644
CWS1220	1T101330209	LBD#1210-P#3 OLD RD, KINGS PARK	STMHR	SCONST	KINGS PARK	6,664	9,444	2,291	0	10,533	28,932	6,664	9,444	6,453	0	11,407	33,968
CWS1220	1T101562920	P#8 COURTLAND DR, BAY SHORE	STMHR	CASBUILT	BAY SHORE	0	0	0	0	0	0	150	111	2,135	21,916	7,068	31,379
CWS1220	1T101562940	P#155 STRAIGHT PATH, W BABYLON	STMHR	CASBUILT	W BABYLON	0	0	0	0	0	0	1,107	714	2,292	18,334	6,482	28,930
					Sub-Total P LIPA Storm Hardening Lines	**26,033**	**37,226**	**11,008**	**904,510**	**827,538**	**1,806,315**	**482,819**	**569,989**	**363,126**	**1,840,931**	**1,485,442**	**4,742,307**
					Sub-Total Property	**26,033**	**37,226**	**11,008**	**904,510**	**827,538**	**1,806,315**	**501,467**	**592,107**	**401,391**	**1,847,354**	**1,494,724**	**4,837,043**
					Grand Total:	**26,033**	**37,226**	**11,008**	**904,510**	**827,538**	**1,806,315**	**501,467**	**592,107**	**401,391**	**1,847,354**	**1,494,724**	**4,837,043**

PSEG Long Island
Case Name: PSEG LI - Rate Case 2015
Docket No(s): Matter No. 15-00262

Response to Discovery Request: CITY-0003
Date of Response: 03/03/2015
Witness: CAPITAL BUDGETS

Question:
Please provide a detailed explanation of the climate and other events that the storm hardening program is designed to address.

Attachments Provided Herewith: 0

Response:
The storm hardening program is designed to address impacts that may be inflicted on the LIPA T&D system by a Category 3 storm, with its associated sustained 130 mph winds and storm surge.

PSEG Long Island
Case Name: PSEG LI - Rate Case 2015
Docket No(s): Matter No. 15-00262

Response to Discovery Request: CITY-0004
Date of Response: 03/03/2015
Witness: CAPITAL BUDGETS

Question:
Please explain how the design standards embedded in the storm hardening program are distinguishable from the design standards underlying other capital projects, if at all.

Attachments Provided Herewith: 0

Response:

The design standards for the transmission system are consistent in all transmission projects.

The design standards embedded in the storm hardening program for electric substations are basically the same as the design standards underlying other capital projects. The design for all substation expansions and new substations are based on being able to withstand a Category 3 storm and its associated 130 mph sustained winds. For stations that have been identified to be in flood zones, elevation of critical equipment is addressed based on the best available FEMA Work Map Flood Zones Data.

The design standards embedded in the distribution system storm hardening program are distinguishable from the design standards underlying other capital projects in that our storm hardened design consists of a narrow profile construction that utilizes shorter and stronger cross arms with more robust hardware (i.e., insulator pins, reinforcing plates, and braces). This narrow profile hardened construction for distribution poles less than 60 feet is designed to meet NESC Rule 250C for extreme wind loading, exceeding the requirements of NESC Rule 250B that apply to poles less than 60 feet.

Included in a storm hardened design is the installation of 45 foot class 2 poles as a minimum along state and county roads, the installation of 40 foot class 2 poles minimum on mainline circuits, burying all poles one foot deeper than required, the installation of a more resilient 336 MCM Aluminum covered conductor for mainlines, replacing open wire secondary with triplex on mainline poles, the installation of additional surge arrestors (every 6 poles), and the installation of additional pole guying. All rear property pole replacements/new installations are a minimum class 2 pole strength.

Another key component of the storm hardening program is the continued expansion of the approximately 1,300 automatic sectionalizing unit (ASU) devices mounted system wide. The number of ASUs utilized per circuit and the installation locations are targeted to maximize the reduction of customer minutes interrupted. The storm hardening standard requires a minimum size class 1/0 (H1) pole for an ASU installation. Additionally, the ASU pole and the two adjacent poles shall have no overhanging limbs or hazardous trees in the vicinity.

PSEG Long Island
Case Name: PSEG LI - Rate Case 2015
Docket No(s): Matter No. 15-00262

Response to Discovery Request: CITY-0005
Date of Response: 02/24/2015
Witness: CAPITAL BUDGETS

Question:
Please identify the specific flood area maps that were relied on when developing the storm hardening program.

Attachments Provided Herewith: 0

Response:
Flood area maps that were relied upon when developing the storm hardening program are:

- NYC - FEMA Best Available Flood Data June 13, 2013 Preliminary Work Map Flood Zones.
- Nassau - FEMA FIRM FLOOD ZONE Map, Revised September 11, 2009
- Suffolk - FEMA FIRM FLOOD ZONE Map, Revised September 25, 2009

PSEG Long Island
Case Name: PSEG LI - Rate Case 2015
Docket No(s): Matter No. 15-00262

Response to Discovery Request: CITY-0006
Date of Response: 03/03/2015
Witness: CAPITAL BUDGETS

Question:
For each weather-related event (including heat waves) that caused customer outages during the period 2010 to present, please provide:

a. the date(s) of the event;

b. the nature of the event;

c. the total number of customers who lost power, by operating area;

d. the amount of time required to restore service to 50% of the customers, broken down by operating area;

e. the amount of time required to restore service to 75% of the customers, broken down by operating area;

f. the amount of time required to restore service to 100% of the customers, broken down by operating area;

g. please separate the total number provided in response to (c) between customers served by overhead systems and underground networks, if applicable;

h. please identify any measures undertaken to harden the Authority's systems in response to each event identified in (b);

i. please describe all analyses performed after each event identified in (b) to evaluate the ability of LIPA's facilities to withstand similar future events;

j. please describe the actions undertaken to implement the results of the evaluations described in (i).

Attachments Provided Herewith: 1
Summary of Storm Periods 2010 2014.xls

Response:
a. See Column "B" of the attached spreadsheet "Summary of Storm Periods 2010 2014". Data for each year is provided in a separate tab of the spreadsheet.

b. See column “F” of the attached spreadsheet “Summary of Storm Periods 2010 2014”. Data for each year is provided in a separate tab of the spreadsheet.

c. Historical storm records included only customers affected at the system level, not by operating area. See column “G” of the attached spreadsheet “Summary of Storm Periods 2010 2014”. Data for each year is provided in a separate tab of the spreadsheet.

d. PSEG LI is not in possession of the data sought in this question.

e. PSEG LI is not in possession of the data sought in this question.

f. PSEG LI storm records included only customers affected at the system level, not by operating area. See attached spreadsheet “Summary of Storm Periods 2010 2014” which includes the start and end time, at the system level, for each storm event as well as the Customer Average Interruption Duration Index (CAIDI) for the storm.

g. The Long Island electric system serves less than 6,200 underground network customers. Outage data is not broken out separately for overhead systems and underground networks. PSEG LI is not in possession of the data sought in this question.

h. Hardening plans are not developed in response to individual storms. Utilizing FEMA Grant funding, approximately 1,000 miles of mainline facilities on 300 distribution circuits will be rebuilt with stronger poles and more robust pole top configurations to reduce the impact of future storms. A hazard mitigation plan will be developed for each circuit.

i. Hardening plans are not developed in response to individual storms. Analysis will be performed by an Engineering and Design contractor under a FEMA Grant. The contractor will be used to develop hazard mitigation plans for approximately 300 distribution circuits and 1,000 miles of mainline facilities.

j. Detailed engineering and design is scheduled to begin in March 2015 for the FEMA funded storm hardening initiatives.

SUMMARY OF 2010 STORM PERIODS

STORM	START DATE	START TIME	END DATE	END TIME	TYPE	CUSTOMERS INTERRUPTED	CUSTOMER MINUTES	STORM CAIDI
1	1/24/2010	1600	1/26/2010	2100	HEAVY RAIN / HIGH WIND	50,206	7,465,372	149
2	2/10/2010	0001	2/11/2010	1300	BLIZZARD	13,723	1,447,817	106
3	3/12/2010	1600	3/25/2010	2359	"THE STORM" HEAVY RAIN / HIGH WIND	294,826	277,070,431	940
4	3/30/2010	0001	3/30/2010	2359	HEAVY RAIN / HIGH WIND	10,250	568,792	55
5	5/8/2010	0001	5/10/2010	0700	HIGH WIND	36,351	7,240,382	199
6	5/18/2010	0800	5/19/2010	0900	HEAVY RAIN / HIGH WIND	5,674	503,938	89
7	5/26/2010	0800	5/27/2010	1800	HEAVY RAIN / THUNDERSTORMS / HEAT	9,091	876,074	96
8	6/22/2010	2000	6/23/2010	2000	HEAT STORM	5,055	536,549	106
9	6/23/2010	2000	6/29/2010	0700	HEAT / THUNDERSTORMS	85,700	36,695,440	428
10	7/4/2010	1700	7/8/2010	0600	HEAT STORM	35,713	4,962,314	139
11	7/13/2010	0800	7/14/2010	0400	HEAVY RAIN / THUNDERSTORMS / HEAT	9,212	1,089,479	118
12	7/18/2010	0800	7/19/2010	0900	HEAVY RAIN / THUNDERSTORMS / HEAT	9,187	534,968	58
13	7/19/2010	0900	7/20/2010	1200	HEAT / THUNDERSTORMS	19,708	2,076,338	105
14	7/21/2010	0800	7/23/2010	0600	HEAT / WIND / THUNDERSTORMS	16,162	5,720,290	354
15	7/23/2010	1800	7/28/2010	0400	HEAT / WIND / THUNDERSTORMS	69,022	21,491,661	311
16	8/5/2010	0001	8/6/2010	0300	HEAT / HUMIDITY	6,387	658,846	103
17	8/22/2010	0800	8/24/2010	0500	HEAVY RAIN / HIGH WIND	23,804	3,236,931	136
18	8/31/2010		9/4/2010		HURRICANE "EARL" ANTICIPATION	0	0	0
19	9/16/2010	0800	9/18/2010	0500	WIND / THUNDERSTORMS	23,135	6,302,465	272
20	9/30/2010	0000	10/2/2010	0400	HEAVY RAIN / HIGH WIND	35,853	3,836,472	107
21	10/14/2010	1500	10/16/2010	2359	HEAVY RAIN / HIGH WIND	20,261	1,383,507	68
22	11/8/2010	0000	11/8/2010	2359	RAIN / GUSTY WINDS	4,513	363,414	81
23	11/16/2010	1600	11/18/2010	0200	RAIN / GUSTY WINDS	13,234	935,048	71
24	12/1/2010	0000	12/2/2010	2200	HEAVY RAIN / HIGH WIND	44,647	6,561,745	147
25	12/12/2010	0000	12/13/2010	0600	HEAVY RAIN / HIGH WIND	6,620	482,067	73
26	12/26/2010	0800	12/28/2010	2300	BLIZZARD 2	70,708	11,584,882	164

SUMMARY OF 2011 STORM PERIODS

STORM	START DATE	START TIME	END DATE	END TIME	TYPE	CUSTOMERS INTERRUPTED	CUSTOMER MINUTES	STORM CAIDI
1	1/18/2011	0000	1/18/2011	2300	HEAVY RAIN	0	0	0
2	1/26/2011	0800	1/27/2011	1600	RAIN / SLEET / SNOW / WIND	11,726	961,700	82
3	2/1/2011	1600	2/3/2011	0600	SLEET / FREEZING RAIN / ICE	20,391	2,694,228	132
4	2/19/2011	0000	2/20/2011	0800	HIGH WINDS	20,452	1,850,110	90
5	2/25/2011	0001	2/26/2011	0600	RAIN / HIGH WINDS	21,225	1,424,498	67
6	3/6/2011	0800	3/7/2011	2359	RAIN / HIGH WINDS	7,682	642,595	84
7	3/10/2011	0800	3/11/2011	0800	RAIN / HIGH WINDS	5,429	461,174	85
8	4/12/2011	1800	4/13/2011	2000	RAIN / LIGHTNING / HIGH WINDS	9,599	1,126,596	117
9	4/16/2011	0700	4/18/2011	0200	RAIN / HIGH WINDS	15,771	1,260,642	80
10	6/8/2011	1800	6/10/2011	1100	HIGH TEMP/THUNDERSTORMS	18,685	1,937,368	104
11	6/17/2011	0001	6/18/2011	0800	SEVERE THUNDERSTORMS	20,035	2,471,824	123
12	7/7/2011	1500	7/9/2011	1800	HEAVY RAIN / STRONG THUNDERSTORMS	27,050	1,316,317	49
13	7/11/2011	2000	7/13/2011	1300	SUSTAINED EXTREME HEAT	13,348	974,603	73
14	7/21/2011	1600	7/24/2011	1400	SEVERE HEAT EVENT	49,436	9,505,210	192
15	7/29/2011	0400	7/30/2011	0600	HEAT/THUNDERSTORMS	8,396	629,808	75
16	8/1/2011	0001	8/2/2011	1200	LIGHTNING/THUNDERSTORMS	16,196	2,128,288	131
17	8/14/2011	0001	8/15/2011	0300	HEAVY RAIN / STRONG THUNDERSTORMS	25,786	2,437,511	95
18	8/18/2011	1600	8/19/2011	1500	RAIN / LIGHTNING	7,936	776,297	98
19	8/21/2011	1400	8/22/2011	2100	RAIN / LIGHTNING	5,558	509,546	92
20	8/27/2011	1600	9/23/2011	2359	HURRICANE "IRENE"	639,209	821,991,647	1,286
21	10/19/2011	0600	10/20/2011	0600	HEAVY RAIN / STRONG GUSTY WINDS	9,791	566,516	58
22	10/29/2011	0700	10/30/2011	2000	RAIN / HIGH WINDS	24,150	2,645,579	110
23	12/7/2011	1600	12/9/2011	0400	HEAVY RAIN / STRONG WINDS	35,686	5,381,347	151
24	12/27/2011	1200	12/29/2011	0900	HEAVY RAIN / STRONG WINDS	32,274	3,890,431	121

SUMMARY OF 2012 STORM PERIODS

STORM	START DATE	START TIME	END DATE	END TIME	TYPE	CUSTOMERS INTERRUPTED	CUSTOMER MINUTES	STORM CAIDI
1	1/11/2012	2000	1/13/2012	1100	HEAVY RAIN / STRONG WINDS	25,853	1,263,387	49
2	4/22/2012	1200	4/23/2012	1500	HEAVY RAIN / STRONG WINDS	8,224	637,969	78
3	6/1/2012	1500	6/2/2012	1800	HEAVY RAIN / STRONG WINDS	8,437	724,360	86
4	6/12/2012	1700	6/13/2012	2359	HEAVY RAIN / WINDS	9,814	689,949	70
5	6/20/2012	1500	6/24/2012	1100	HEAT STORM / THUNDERSTORMS	62,255	9,368,276	150
6	6/25/2012	0001	6/26/2012	0600	THUNDERSTORMS	44,570	2,771,090	62
7	6/29/2012	1500	6/30/2012	2200	HEAT STORM	7,317	569,539	78
8	7/1/2012	1400	7/2/2012	1400	HEAT STORM	5,358	463,817	87
9	7/7/2012	1500	7/8/2012	1500	HEAT / THUNDERSTORMS	8,961	685,886	77
10	7/15/2012	0800	7/17/2012	0700	HEAT / THUNDERSTORMS	16,033	2,285,347	143
11	7/18/2012	1100	7/20/2012	0200	HEAT / THUNDERSTORMS	40,192	9,255,230	230
12	7/24/2012	0600	7/25/2012	0600	HEAT / THUNDERSTORMS	5,532	403,687	73
13	7/26/2012	0700	7/27/2012	0700	HEAT / THUNDERSTORMS	8,227	763,587	93
14	8/5/2012	0700	8/6/2012	1400	HEAT / THUNDERSTORMS	10,515	1,159,635	110
15	8/10/2012	1200	8/11/2012	1200	HEAT / THUNDERSTORMS	5,136	610,749	119
16	8/14/2012	1500	8/16/2012	0200	HEAT / THUNDERSTORMS	18,237	1,294,044	71
17	9/4/2012	1500	9/5/2012	2300	HEAVY RAIN - THUNDERSTORMS	6,938	489,539	71
18	9/8/2012	0800	9/9/2012	0800	HEAVY RAIN - THUNDERSTORMS	5,507	676,555	123
19	9/18/2012	0001	9/19/2012	2000	HEAVY RAIN / HIGH WINDS	46,615	5,963,855	128
20	10/28/2012	0001	11/30/2012	2359	HURRICANE "SANDY"	1,171,061	2,698,954,977	2,305
21	12/7/2012	0800	12/8/2012	1800	RAIN AND WIND	9,283	1,035,730	112
22	12/9/2012	1500	12/10/2012	2359	RAIN AND WIND	5,402	724,717	134
23	12/20/2012	1600	12/22/2012	0400	HEAVY RAIN / STRONG GUSTY WINDS	25,154	3,992,636	159
24	12/26/2012	0800	12/27/2012	2200	HEAVY RAIN / HIGH WINDS	24,991	4,535,679	181
25	12/29/2012	1600	12/30/2012	2359	RAIN / SNOW / HIGH WINDS	7,369	544,105	74

SUMMARY OF 2013 STORM PERIODS

STORM	START DATE	START TIME	END DATE	END TIME	TYPE	CUSTOMERS INTERRUPTED	CUSTOMER MINUTES	STORM CAIDI
1	1/30/2013	1500	2/2/2013	0259	HEAVY RAIN / HIGH WINDS	78,123	20,675,125	264.6
2	2/8/2013	0001	2/12/2013	0200	BLIZZARD "NEMO"	59,983	17,337,035	289.0
3	2/17/2013	0700	2/18/2013	1100	HIGH WINDS	6,256	469,426	75.0
4	2/26/2013	1500	2/27/2013	2000	HIGH WIND / HEAVY RAIN	3,786	361,029	95.4
5	3/6/2013	1200	3/8/2013	0800	WIND / RAIN / SNOW / ICE	9,384	738,408	78.7
6	5/24/2013	1600	5/26/2013	2200	HIGH WIND / HEAVY RAIN	15,419	1,534,263	99.5
7	6/7/2013	0001	6/8/2013	1900	HEAVY RAIN / HIGH WIND	15,753	1,236,511	78.5
8	6/13/2013	0800	6/14/2013	1200	HEAVY RAIN / WIND	13,022	1,134,554	87.1
9	6/24/2013	0700	6/25/2013	0200	HEAT / THUNDERSTORMS	8,040	643,265	80.0
10	6/25/2013	0201	6/26/2013	0200	HEAVY RAIN / WIND	13,308	660,409	49.6
11	7/5/2013	0700	7/9/2013	1600	HEAT AND HUMIDITY	28,444	2,231,507	78.5
12	7/15/2013	0700	7/21/2013	0800	HEAT AND HUMIDITY	64,951	5,957,709	91.7
13	7/23/2013	0001	7/23/2013	2359	HEAT / THUNDERSTORMS	6,920	567,127	82.0
14	9/3/2013	0001	9/4/2013	0100	HEAVY RAIN / THUNDERSTORMS	10,797	1,041,087	96.4
15	10/7/2013	0800	10/8/2013	0500	HEAVY RAIN / WIND	12,262	851,674	69.5
16	10/31/2013	2300	11/1/2013	2300	HEAVY RAIN / WIND	2,538	341,470	134.5
17	11/24/2013	0001	11/25/2013	0200	STRONG GUSTY WINDS	4,231	595,070	140.6
18	11/26/2013	1500	11/28/2013	0300	STRONG GUSTY WINDS / RAIN	40,837	4,752,737	116.4

SUMMARY OF 2014 STORM PERIODS

STORM	START DATE	START TIME	END DATE	END TIME	TYPE	CUSTOMERS INTERRUPTED	CUSTOMER MINUTES	STORM CAIDI
1	1/6/2014	1200	1/7/2014	1600	RAIN / STRONG WINDS	5,053	328,579	65
2	2/3/2014	0800	2/4/2014	0700	SNOW / ICE STORM	15,435	1,568,054	102
3	2/4/2014	2200	2/6/2014	0600	SNOW / ICE STORM	22,485	3,135,747	139
4	2/13/2014	0000	2/14/2014	0700	WIND / RAIN / SNOW	13,584	662,113	49
5	3/26/2014	0600	3/26/2014	2359	STRONG WINDS	4,052	341,667	84
6	4/15/2014	0700	4/16/2014	0800	HEAVY RAIN	11,786	1,154,810	98
7	5/16/2014	1600	5/17/2014	1900	HEAVY RAIN / STRONG WINDS	11,754	1,488,908	127
8	7/2/2014	1200	7/3/2014	1300	HEAVY RAIN / STRONG WINDS	7,342	1,346,969	183
9	7/3/2014	1300	7/4/2014	1900	HEAVY RAIN	7,922	1,188,101	150
10	7/8/2014	1600	7/9/2014	1900	HEAVY RAIN / STRONG WINDS	8,502	1,430,163	168
11	7/14/2014	1600	7/16/2014	1200	HEAVY RAIN / STRONG WINDS	25,278	2,971,649	118
12	8/13/2014	0000	8/14/2014	0000	HEAVY RAIN	13,671	2,677,308	196
13	10/22/2014	0001	10/23/2014	1500	HEAVY RAIN / STRONG WINDS	30,201	3,350,254	111
14	11/1/2014	0700	11/3/2014	0400	RAIN / STRONG WINDS	28,219	3,822,284	135
15	11/24/2014	0000	11/24/2014	2300	HEAVY RAIN / STRONG WINDS	15,966	1,285,144	80
16	12/9/2014	0000	12/9/2014	2359	HEAVY RAIN	4,253	370,252	87

PSEG Long Island
Case Name: PSEG LI - Rate Case 2015
Docket No(s): Matter No. 15-00262

Response to Discovery Request: CITY-0009
Date of Response: 03/05/2015
Witness: CAPITAL BUDGETS

Question:
Are storm hardening design concepts integrated into capital projects not included within the storm hardening plan? Please explain your answer fully.

Attachments Provided Herewith: 0

Response:
Yes, storm hardening design concepts are integrated into capital projects outside the scope of the storm hardening plan.

Transmission:
- All new transmission lines are designed to withstand Category III 130 mph wind criteria
- Increased pole depths are used for flood zone areas
- Steel poles with concrete bases are utilized along ROWs and LIRR lines
- Poles replaced utilize a two class size increase of existing pole

Substations:
- Avoid flood zones or design appropriate control measures such as raised equipment
- Design to withstand Category III 130 mph wind criteria

Distribution:
- Storm hardening design concepts are covered under the storm hardening plan. Refer to CITY-0004

PSEG Long Island
Case Name: PSEG LI - Rate Case 2015
Docket No(s): Matter No. 15-00262

Response to Discovery Request: CITY-0011
Date of Response: 03/03/2015
Witness: CAPITAL BUDGETS

Question:
How many customers experienced electric service interruptions due to Hurricane Sandy? Please specify the number of customers interrupted within each operating area and the amount of time it took to restore service in each location.

Attachments Provided Herewith: 0

Response:

Operating Division	**# of Customers Affected**	**Restoration Time**
Queens-Nassau	**175,000**	Approx. 14 days
Central	**268,000**	Approx. 14 days
Western Suffolk	**317,000**	Approx. 14 days
Eastern Suffolk	**434,000**	Approx. 14 days
Totals	**1,194,000**	Approx. 14 days

Sandy and the ensuing nor'easter that brought 123,000 additional customer outages resulted in 1,194,000 customers outages that were restored in just over two weeks.

PSEG Long Island
Case Name: PSEG LI - Rate Case 2015
Docket No(s): Matter No. 15-00262

Response to Discovery Request: CITY-0012
Date of Response: 03/05/2015
Witness: CAPITAL BUDGETS

Question:
a. Does LIPA/PSEG have a capital expenditure prioritization process? If so, please describe it in detail.

b. If the answer to the preceding question is affirmative, please explain how storm hardening-related projects fit within the capital expenditure prioritization process.

Attachments Provided Herewith: 0

Response:

a. Yes, LIPA/PSEG LI have a capital expenditure prioritization process, as described in the Capital Budget Panel Direct Testimony.

   The number of requested projects (and associated capital expenditures) in any specific year is significantly higher than the historical annual spending. In order to select and optimize capital expenditures, we are using a prioritization and optimization process supported by an Intranet-based tool, "T&D Projects Risk Scoring and Prioritization". This tool evaluates each project by determining impact of funding or not funding the specific project against 30 different "risk drivers". Risk drivers are developed based on and consistent with longer term strategic goals as defined for four major business performance areas: Technical/Reliability System Performance, Customer Satisfaction, Financial Performance, and Regulatory Compliance. Level of risk and/or impact of a project on a specific risk driver is graded and determined at ten levels – starting from 0 (no impact) to 10 (hazardous impact). In addition to impact level, each project is analyzed to determine likelihood of specific adverse event or adverse situation that the proposed project is addressing. Probabilities of failures, exposure time, and the probability of timely prevention of adverse impact are used to calculate the likelihood of an adverse event. Level of impact (0-10) and likelihood (0-10) are used to calculate Risk Ranking Number (RRN) for each proposed project (0-100). All projects in the portfolio of proposed projects for that specific year are ranked by Risk Ranking Number from the highest to the lowest. Lowest ranked projects are further discussed for accuracy of risk ranking and understanding of all possible consequences of not funding and/or project deferral. Finally, based on available annual budget for capital expenditure a specific number of projects with highest RRN is selected for funding. This process is repeated each year.

b. Over last few years, due to the extraordinary impact of two major storms, this process is coordinated with FEMA and NYS funding in order to ensure effective restoration of system reliability after extraordinary storm damage and for optimum use of all available funding.

Storm hardening projects are funded through four major mechanisms:

1) internal commitment and dedicated funding of storm hardening projects.

2) upgrading for storm hardened infrastructure as a part of most new capital investment projects (where appropriate), even if specific projects are initiated for capacity upgrades and/or replacements of aged assets.

3) prioritizing use of funding of asset maintenance, for example, vegetation management to improve storm resilience and storm-hardened reliability of high risk assets and circuits.

4) special and/or specific projects funded by NYS, FEMA, and internal emergency funding as required during and after unplanned and extraordinary storms, such as the most recent two major storms. In 2014 FEMA awarded LIPA a grant of approximately $729 million to harden electric facilities on Long Island against future storm damage. It is expected that this grant will be utilized during budget year 2015 through 2018.

During the budget years in which storm hardening work will be done using FEMA funding, LIPA’s internal capital storm hardening program has been essentially suspended due to the scope and size of the FEMA program.

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

In the Matter of a Three-Year Rate Proposal for Electric Rates and Charges Submitted by the Long Island Power Authority and Service Provider, PSEG Long Island LLC **Matter No.: 15-00262**

CITY OF NEW YORK'S SECOND SET OF INFORMATION REQUESTS TO LONG ISLAND POWER AUTHORITY AND PSEG LONG ISLAND LLC

Tom Falcone:

18. With reference to your response to DPS-TF-121, please specify:

a. the total amount of funds received to date from the Federal Emergency Management Agency ("FEMA");
Answer: $1,052,368,100.88

b. incremental funds awarded by FEMA that have not yet been received by LIPA, if any;
Answer: $381,834,666

c. the total amount of funds received to date from the Housing Trust Fund Corporation ("HTFC");
Answer: $80,000,000

d. incremental funds awarded by HTFC that have not yet been received by LIPA, if any;
Answer: LIPA entered into a sub recipient agreement with HFTC dated September 29, 2014 that would entitle LIPA to a maximum grant of $143,420,276. The Authority has received $80 million per (c). This amount was a partial reimbursement for the "local match" share of the FEMA grant for storm restoration for recent declared weather events. The Authority anticipates that it may be eligible for an additional approximately $27 million of reimbursements for the "local match" for storm restoration. The remaining balance of approximately $36 million may be used for vegetation management completed by December 31, 2015, if eligible.

e. all local, State, or Federal entities other than FEMA and HTFC that have awarded LIPA funds for storm hardening projects;
Answer: None

f. the total amount of funds received to date from entities specified in (e), if any, and
Answer: N/A

g. the total amount of funds to be received from entities specified in (e), if any.
Answer: None

Response Date: March 3, 2015
Witness: Tom Falcone

19. What portion of total storm hardening expenditures will be paid for, or reimbursed by, funds identified in response to City-18?

Answer: Approximately 90% of the storm hardening expenditures will be paid for or reimbursed by funds identified in response to City-18.

20. Are the funds identified in City-18 used exclusively to reimburse capital expenditures funded initially by rates, or may those funds be used to finance capital expenditures in the first instance? Please explain your answer fully.

Answer: Under the terms of the Letter of Undertaking dated February 20, 2014, up to $704,507,766 will be used to reimburse the Authority for costs incurred to repair the system after Hurricane Sandy and $729,695,000 million is for use to harden the T&D system. These values represent 100% of the costs covered by the LOU, of which 90% will be funded by FEMA and the balance represents the "local match."

The $729,695,000 portion of the grant will fund the construction of the storm hardened facilities on a reimbursement basis. The storm hardening capital expenditures are incremental to the annual system capital budget. As noted above the Authority has received pre-funding for a portion of the $729 million (which is held separate and apart from other Authority funds for this purpose and will be used to reimburse Authority funds for eligible expenditures), and is working to put in place a reimbursement mechanism to ensure timely receipt of the balance of funds.

21. The Letter of Understanding ("LOU") with FEMA (the "FEMA-LOU") attached to your response to DPS-TF-121 states, in item number 1 under "Primary Essential Elements" on page 1, that the "Parties have agreed upon the damages caused as a direct result of Hurricane Sandy, the associated dimensions, a detailed description of those damages, and an eligible scope of work that will be captured in the PW that FEMA will generate for this facility." Please provide all communications, reports, analyses, and other information underlying the statements in the preceding quote.

Answer: All relevant communications are summarized in the PW.

22. Please specify how storm hardening and resilience design concepts were incorporated into the repair work identified on Table 1, page 2 of the FEMA-LOU.

Answer: We have referred this question to PSEG Long Island

23. Please specify how storm hardening and resilience design concepts were incorporated into the repair work identified on Table 2, page 2 of the FEMA-LOU.

Answer: We have referred this question to PSEG Long Island

24. With respect to Table 2 on page 2 of the FEMA-LOU:

  a. please identify, by name and location, the transmission lines that will be strengthened to 130 mph level of protection;

Response Date: March 3, 2015
Witness: Tom Falcone

b. for each transmission line identified in (a), please estimate the wind speed from Hurricane Sandy that actually impacted the line; and

c. please explain why 130 mph was chosen as the design level of protection.

Answer: We have referred these questions to PSEG Long Island

25. a. Did Hurricane Sandy damage any transmission lines not identified in response to City-24?

b. If the answer to (a) is in the affirmative, please explain whether those transmission lines were (or will be) upgraded to withstand stronger wind speeds than impacted the damaged assets.

Answer: We have referred these questions to PSEG Long Island

26. With respect to Table 2 on page 2 of the FEMA-LOU:

a. please identify, by name and location, each substation that was damaged by Hurricane Sandy;

b. please specify the maximum flood level observed at each substation identified in (a);

c. please identify the "substation equipment damaged during Sandy" for each substation identified in (a);

d. please specify the initial elevation and incremental change in elevation for each asset identified in (c) that will result from the asset elevation work referenced on Table 2; and

e. please specify the flood maps that were used to develop the asset elevation work referenced on Table

Answer: We have referred these questions to PSEG Long Island

27. Please describe the mainline circuit hardening program referenced on Table 2, page 2 of the FEMA-LOU. Please include in your answer the locations of all circuits included in this program, and please discuss the current status of the program.

Answer: We have referred this question to PSEG Long Island

28. Please describe the program to install Automatic Sectionalizing Units ("ASUs") that is referenced on Table 2, page 2 of the FEMA-LOU. Please include in your answer the purpose of this program, the locations of all ASUs to be installed, and please discuss the current status of the program.

Answer: We have referred this question to PSEG Long Island

29. Please provide the benefit-cost analysis referenced on page 3 of the FEMA-LOU.

Response Date: March 3, 2015
Witness: Tom Falcone

Answer: The benefit-cost analysis was performed by FEMA using a proprietary model for the types of storm hardening expenditures used in the grant. This is not an Authority or PSEG Long Island work product.

30. Please provide the maintenance and easement support management plan referenced on page 3 of the FEMA-LOU.

Answer: We have referred this question to PSEG Long Island

31. Please provide the documentation referenced in item number 11 on page 4 of the FEMA-LOU.

Answer: We have referred this question to PSEG Long Island

Response Date: March 3, 2015
Witness: Tom Falcone

PSEG Long Island
Case Name: PSEG LI - Rate Case 2015
Docket No(s): Matter No. 15-00262

Response to Discovery Request: CITY-0022
Date of Response: 03/17/2015
Witness: CAPITAL BUDGETS

Question:
Please specify how storm hardening and resilience design concepts were incorporated into the repair work identified on Table 1, page 2 of the FEMA-LOU.

Attachments Provided Herewith: 0

Response:

Table Number 1 of the FEMA Letter of Intent details the general categories of LIPA's eligible repair/restoration costs following Superstorm Sandy. Restoration work on distribution lines was performed to restore the system to pre-storm configurations after mitigation of the hazard that caused the damage (e.g., removal of a downed tree or limb).

Transmission line restoration was performed so that poles and hardware replaced were reconstructed to withstand wind speeds up to 130 mph (Category 3 Hurricane level).

Restoration of flood damaged substation equipment was done to allow service to return to customers as quickly as possible. This initial restoration effort was accomplished through temporary cleaning measures and some equipment replacement. In cases where cleaning was performed, the plan includes an eventual change-out of equipment since the salt water contamination persists despite continued cleaning. At the two most severely damaged substations, flood damaged equipment was also elevated raising equipment above Sandy flood levels. The sensitive equipment in eight other flood prone substations is being/has been elevated to levels recommended by a special study done for PSEG Long Island based on revised FEMA recommended flood levels.

PSEG Long Island
Case Name: PSEG LI - Rate Case 2015
Docket No(s): Matter No. 15-00262

Response to Discovery Request: CITY-0023
Date of Response: 03/17/2015
Witness: CAPITAL BUDGETS

Question:
Please specify how storm hardening and resilience design concepts were incorporated into the repair work identified on Table 2, page 2 of the FEMA-LOU.

Attachments Provided Herewith: 0

Response:
In accordance with FEMA requirements, bids have been solicited for engineering and design contractors to develop hardening and resilience plans for each of the FEMA targeted mitigation measures. FEMA Grant funded storm hardening and resilience is currently beginning the engineering/design phase with construction to start on distribution circuits in 1 to 2 months.

Repair work done following Superstorm Sandy did not incorporate hardening and resilience concepts, except for two flooded substations where some equipment was elevated above Sandy flood levels. The Hazard Mitigation Proposal referred to in Table 2 of the FEMA Letter of Understanding was agreed to between LIPA and FEMA in March of 2014 approximately a year after the completion of Superstorm Sandy repair work.

PSEG Long Island
Case Name: PSEG LI - Rate Case 2015
Docket No(s): Matter No. 15-00262

Response to Discovery Request: CITY-0024
Date of Response: 03/20/2015
Witness: CAPITAL BUDGETS

Question:
With respect to Table 2 on page 2 of the FEMA-LOU:
a. please identify, by name and location, the transmission lines that will be strengthened to 130 mph level of protection;
b. for each transmission line identified in (a), please estimate the wind speed from Hurricane Sandy that actually impacted the line; and
c. please explain why 130 mph was chosen as the design level of protection.

Attachments Provided Herewith: 0

Response:

a. Table 2 of the FEMA/NYS/LIPA Letter of Understanding ("LOU") lists $ 5,000,000 for estimated costs to strengthen damaged transmission lines to 130 mph level of protection. No Transmission circuit mitigation plans have been developed at this time.
b. No Transmission circuit mitigation plans have been developed as of this request date.
c. 130 mph was chosen as a design standard so that transmission lines could withstand the highest winds of a Category 3 hurricane. Historically Long Island has experienced a maximum hurricane rating of category 3 strength (e.g., the 1938 Hurricane).

PSEG Long Island
Case Name: PSEG LI - Rate Case 2015
Docket No(s): Matter No. 15-00262

Response to Discovery Request: CITY-0025
Date of Response: 03/11/2015
Witness: CAPITAL BUDGETS

Question:
a. Did Hurricane Sandy damage any transmission lines not identified in response to City-24?
b. If the answer to (a) is in the affirmative, please explain whether those transmission lines were (or will be) upgraded to withstand stronger wind speeds than impacted the damaged assets.

Attachments Provided Herewith: 0

Response:
No transmission lines have currently been identified for hardening. All transmission poles damaged during Sandy were replaced with poles suitable to withstand up to 130 mph winds. In addition, FEMA funding of $5,000,000 for transmission line hardening will only support the hardening of several highest risk transmission line segments and not any entire transmission circuit.

PSEG Long Island
Case Name: PSEG LI - Rate Case 2015
Docket No(s): Matter No. 15-00262

Response to Discovery Request: CITY-0026
Date of Response: 03/17/2015
Witness: CAPITAL BUDGETS

Question:
With respect to Table 2 on page 2 of the FEMA-LOU:
a. please identify, by name and location, each substation that was damaged by Hurricane Sandy;
b. please specify the maximum flood level observed at each substation identified in (a);
c. please identify the "substation equipment damaged during Sandy" for each substation identified in (a);
d. please specify the initial elevation and incremental change in elevation for each asset identified in (c) that will result from the asset elevation work referenced on Table 2; and
e. please specify the flood maps that were used to develop the asset elevation work referenced on Table 2.

Attachments Provided Herewith: 1
CITY_0026_CITY-0026 Attachment.xlsx

Response:

Please see Attachment.

Substation Name	Substation Location	Actual Sandy Flooding in Substation (feet)	Substation Equipment Damaged During Sandy	Initial equipment foundation elevation above sea level (NAVD88)(feet)	New equipment foundation elevation above sea level (NAVD88)(feet)	FEMA BFE Elevations (feet)
Arverne	Far Rockaway, NY	6.1	Two (2) half lineups of 13kV switchgear	6.9	10.9' - 13kV swgrs	FEMA Best Available Flood Data 6/13/13 Preliminary Work Map Flood Zones - AE (EL 10)
			One (1) full lineup of 38kV switchgear	6.9	38kV swgr elevation planned for 12.75'	
Atlantic Beach	Atlantic Beach, NY	N/A	13kV and 4kV swgrs, transformer control cabinets, control equipment	N/A	Substation removed from service	
Barrett	Island Park, NY	1.5	One(1) full lineup of 13kV switchgear and one (1) half lineup of 13kV switchgear	11 ft	16.35' - swgrs	FEMA FIRM FLOOD ZONE Map Revised Sept. 11, 2009 - AE (EL 9)
Captree	Captree Island, NY	0.5	Damage limited to components, not entire assemblies.	4.4	No equipment elevation planned. Permanent flood walls have been installed surrounding the substation to height of of 7.1'	FEMA FIRM FLOOD ZONE Map Revised Sept. 25, 2009 - AE (EL 5)
Fair Harbor	Fire Island, NY	2.4	Damage limited to components, not entire assemblies.	5.75	No equipment elevation planned. Permanent flood walls have been installed surrounding the substation to height of of 7.6'	FEMA FIRM FLOOD ZONE Map Revised Sept. 25, 2009 - AE (EL 7)
Far Rockaway	Far Rockaway, NY	4.7	Two (2) full lineups of 13kV switchgear	5.5	13kV swgrs elevation planned for 12.5'	FEMA Best Available Flood Data 6/13/13 Preliminary Work Map Flood Zones - AE (EL 9)
			One (1) full lineup of 38kV switchgear	6.4	38kV swgr elevation planned for 12.5'	
			One (1) control enclosure	7.6	control enclosure elevation planned for 12.5'	
Long Beach	Long Beach, NY	3.8	Two (2) half lineups of 13kV switchgear	7.0	13.15' - swgrs	FEMA FIRM FLOOD ZONE Map Revised Sept. 11, 2009 - AE (EL 10)
Neponsit	Neponsit, NY	11.5	13kV and 4kV swgrs, transformer control cabinets, control equipment	9.2	Substation removed from service	
Ocean Beach	Fire Island, NY	3.7	Damage limited to components, not entire assemblies.	3.2	No equipment elevation planned. Permanent flood walls have been installed surrounding the substation to height of of 6.3'	FEMA FIRM FLOOD ZONE Map Revised Sept. 25, 2009 - AE (EL 7)
Park Place	Long Beach, NY	4.8	One (1) half lineup of 13kV switchgear	6.4	12.0' - sgwr	FEMA FIRM FLOOD ZONE Map Revised Sept. 11, 2009 - AE (EL 8)
			One (1) control enclosure	6.4	12.67' - control encl	
Rockaway Beach	Rockaway Beach, NY	4.8	Two (2) half lineups of 13kV switchgear	8.2	14.13' - sgwrs	FEMA Best Available Flood Data 6/13/13 Preliminary Work Map Flood Zones - AE (EL10)
			One (1) control enclosure	8.2	14.3' - control encl	
Woodmere	Woodmere, NY	2.7	Two (2) half lineups of 13kV switchgear	7.6	12.9' swgrs	FEMA FIRM FLOOD ZONE Map Revised Sept. 11, 2009 - AE (EL 11)
			One (1) control enclosure	7.6	control enclosure elevation planned for 13.75'	

PSEG Long Island
Case Name: PSEG LI - Rate Case 2015
Docket No(s): Matter No. 15-00262

Response to Discovery Request: CITY-0027
Date of Response: 03/18/2015
Witness: CAPITAL BUDGETS

Question:
Please describe the mainline circuit hardening program referenced on Table 2, page 2 of the FEMA-LOU. Please include in your answer the locations of all circuits included in this program, and please discuss the current status of the program.

Attachments Provided Herewith: 0

Response:
The program to harden distribution circuit mainlines will include the following measures to strengthen lines against future damage;

- Replacing smaller poles with larger poles capable of withstanding greater wind forces and impact damage from tree & branches
- Installing new poles 1 foot deeper in the ground than existing poles to increase resistance to high winds and the softening of soil by heavy rains.
- Installing new poles with gravel backfill to further their ability to withstand high winds and storm damage.
- Increased guying to strengthen poles.
- Increased insulation on primary voltage conductors being replaced to better resist contact with storm blown branches.
- The addition of Automated Sectionalizing devices to isolated damaged sections of line allowing quick restoration of service to customers on the undamaged portions of circuits.
- Limited use of underground bypasses of overhead lines in the highest risk areas.

Engineering and design work to identify mitigation zones and corrective action is currently ongoing. Construction work is expected to start in the Summer of 2015. See response to Data Request City-0031 for a list of the distribution circuits included in the storm hardening program.

PSEG Long Island
Case Name: PSEG LI - Rate Case 2015
Docket No(s): Matter No. 15-00262

Response to Discovery Request: CITY-0028
Date of Response: 03/17/2015
Witness: CAPITAL BUDGETS

Question:
Please describe the program to install Automatic Sectionalizing Units ("ASUs") that is referenced on Table 2, page 2 of the FEMA-LOU. Please include in your answer the purpose of this program, the locations of all ASUs to be installed, and please discuss the current status of the program.

Attachments Provided Herewith: 0

Response:
In accordance with FEMA requirements, bids have been solicited for engineering and design contractors to develop hardening and resilience plans for each of the FEMA targeted mitigation measures. These measures include the addition of new Automatic Sectionalizing Switches.

Currently most distribution circuits have one mid-circuit automated switch and one end-circuit automated switch. The mid-point automated switches are used to isolate faults on a circuit allowing half the customers served by the circuit to avoid an interruption in service for faults on either the first or second half of a circuit. The end-point switch can be used to tie a circuit to an adjacent distribution circuit if needed.

For faults on the second half of a circuit's distribution mainline, the mid-circuit switch will open automatically allowing the customers on the first half of the circuit to maintain power while repairs are being made at the fault location on the 2nd half of the circuit. For faults on the first half of a circuit, the mid-circuit switches are opened and the end-circuit switch is closed allowing power to be almost immediately rerouted to customers on the second half of the faulted circuit.

The engineering to identify the location of new switches has yet to begin. However, it is planned that at least two new switches will be added to each of the 300 FEMA targeted circuits. This is expected to allow faults to be isolated such that only approximately 25% of the customers on a circuit will experience an interruption in service for a fault anywhere on the mainline of the circuits. Additional tie-point switches will also be added where possible to increase the availability of sources to transfer un-faulted sections of mainline. Additional end-point switches can only be added to circuits with the capacity to carry additional customer load. Not all circuits have the capability such that addition tie-point switches can be established for all circuits.

FEMA storm hardening and resilience is currently beginning the engineering/design phase with construction to start on distribution circuits in summer, 2015.

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

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

Matter No.: 15-00262

CITY OF NEW YORK'S THIRD SET OF INFORMATION REQUESTS TO LONG ISLAND POWER AUTHORITY AND PSEG LONG ISLAND LLC

Tom Falcone:

32. Please provide the "PW" referenced in your response to City-21.

RESPONSE:

Please see attached.

Response Date: March 24, 2015

PA-02-NY-4085-PW-00367(3) P	
Applicant Name:	Application Title:
LONG ISLAND POWER AUTHORITY	UUMIZ01 Overhead Power Distribution Lines
Period of Performance Start:	Period of Performance End:
10-30-2012	04-30-2014

Bundle Reference # (Amendment #)	Date Awarded
PA-02-NY-4085-State-0151(151)	12-26-2013

Subgrant Application - FEMA Form 90-91

Note: The Effective Cost Share for this application is 90%

FEDERAL EMERGENCY MANAGEMENT AGENCY
PROJECT WORKSHEET

DISASTER	PROJECT NO.	PA ID NO.	DATE	CATEGORY
FEMA 4085 - DR -NY	UUMIZ01	000-UUMIZ-00	07-10-2014	F

APPLICANT: LONG ISLAND POWER AUTHORITY	WORK COMPLETE AS OF: 07-10-2014 : 69 %

Site 1 of 4

DAMAGED FACILITY: Electric Overhead Power Distribution System	COUNTY: Statewide

LOCATION:	LATITUDE:	LONGITUDE:
PA-02-NY-4085-PW-00367(0): System Wide	40.76595	-73.51211

DAMAGE DESCRIPTION AND DIMENSIONS:

PA-02-NY-4085-PW-00367(0):

Applicant Long Island Power Authority (LIPA) is a non-profit municipal electric provider that owns the retail electric Transmission and Distribution System on Long Island and provides electric service to more than 1.1 million customers in Nassau and Suffolk counties and the Rockaway Peninsula in Queens. The applicant serves these customers from 171 distribution substations feeding 900 overhead (8902 miles of line) and underground (4226 miles of line) power distribution circuits.

During the incident period of Oct 27, 2012 to Nov 8, 2012, hurricane-generated storm surge and strong wind caused extensive damage to the power infrastructure throughout the applicant's four divisions on Long Island, New York, resulting in power outages for approximately 97% of the customer base. Disaster-related damages occurred when strong winds caused trees and broken limbs to fall into and across overhead electric distribution circuits damaging poles, transformers, power lines, insulators, fuses, and miscellaneous pole structure hardware.

LIPA's four Divisions sustained damages to 877 overhead circuits linked to 149 substations, each of which are connected to and feed multiple overhead electric distribution circuits. The disaster-related damages occurred when strong winds caused trees and broken limbs to fall into and across overhead electric distribution circuits, damaging poles, transformers, power lines, insulators, fuses, and miscellaneous pole structure hardware. To validate the dimensions and quantities of the disaster-related damages to LIPA's overhead electric distribution circuits, the FEMA Public Assistance Team physically inspected 149 circuits (7097 sites) or 17% of 877 overhead distribution circuits to validate the damages. The circuits inspected included: 32 substations in the Queens Nassau Division, 33 substations in the Central Nassau Division, 41 substations in the Western Suffolk Division, and 43 substations in the Eastern Suffolk Division. The sample population was taken from applicant-provided downloads of the damage locations (customer call-in reports, visual observation by non-electrical personnel, work orders, etc.) and 1 circuit from each 149 substation was selected for validation. The 17% damage validation did not result in any exceptions (100% positive rate), which provides reasonable assurance at the 95% confidence level (0 deviations) that entire population of damages identified by the Applicant for all 877 overhead circuits were caused by the disaster, not due to applicant negligence/lack of maintenance, were LIPA's legal responsibility, and accurately reported in terms of quantities and scope of damages. The 17% validated by the FEMA Public Assistance Team exceeds the attribute sample population of 60 recommended by the American Institute of Certified Public Accountants (AICPA) in audit standard "AU Section 350, Audit Sampling".

Based upon inspections of 7097 sites and review of supporting documentation of the damages, the following specific disaster-damaged items were identified:

1. 4,999 wood poles.
2. 8,136 cross arms.
3. 3,258 transformers of various sizes.
4. 454 miles of conductors.
5. Assorted miscellaneous pole structure hardware and auxiliary overhead distribution components.

This PW consists of 3 site sheets that identify the specific damages and scopes of work associated with the following categories:

Site Sheet #1 - Overhead Power Distribution Line Repairs.
Site Sheet #2 – Materials Utilized for the Line Repairs.
Site Sheet #3 - Incidental Cutting/Dropping of Trees Necessary for Line Repair Work.

The GPS coordinates identified for this PW are for the LIPA/National Grid offices located at 175 East Old Country Road, Hicksville, NY 11801.

PA-02-NY-4085-PW-00367(2):

This Amendment 2 is prepared to provide additional reimbursement for activities performed in the repair of LIPA's overhead electric distribution system. It will de-obligate material costs, sales tax, and stores loading rate related to the material costs; which were initially covered in version zero, but were subsequently included in PWs 404 and 2569 for emergency protective measures.
The initial cost associated with contract services as documented in PW # 00367 (0) was $305,079,754.00. As of 09/17/13, a total of $374,679,450.65 has been expended on subcontract line and tree crews to aid in the repair of the overhead electric distribution system. The difference between the updated amount of $374,679,450.65, less overpayments of $7,442.18 and the previous expenditure of $305,079,754.20 (as documented in the original PW #00367(0)) is $69,592,254.27. The aforementioned differential costs of $69,592,254.27 that is addressed in this amendment provides for contract services only; however, sales tax for associated work is also included.
DAC costs were competitively bid and properly procured in accordance with LIPA's procurement policy.

Current Version:

Version 3 is being written to outline the Section 428 capped grant and to identify the damages and costs associated with the repair work to damaged lines, substations and electric meters. Specific mitigation proposals for damaged circuits and substations will be addressed in future versions.
The Applicant, Long Island Power Authority (LIPA), has requested the opportunity and responsibility to utilize the flexibility of Section 428 to aggregate the costs for repair/replacement and mitigation of its facilities damaged by Hurricane Sandy into a fixed, capped grant utilizing the Public Assistance Alternate Procedures (PAAP).
On January 29, 2013, President Obama signed into law the Sandy Recovery Improvement Act of 2013 (P.L. 113-2) (SRIA). The law authorizes several significant changes to the way the Federal Emergency Management Agency (FEMA) may deliver disaster assistance under a variety of programs. Section 1102 of the Act revises the Stafford Act creating a new Section 428 that authorizes the Administrator to establish and adopt alternative procedures for administering federal assistance under the Public Assistance program. Specific implementation procedures were released on December 19, 2013 memorialized in the Public Assistance Alternative Procedures (PAAP) Pilot Program Guide for Permanent Work. A Letter of Understanding (LOU) dated February 20, 2014, was executed between FEMA, the State of New York (the Grantee) and LIPA (the Sub-Grantee) in a consistent manner with the program.
Subject to the provisions of Section 428 of the Stafford Act, working in conjunction with the Applicant's staff, FEMA has developed the Disaster Damage and Dimensions (DDD) and eligible Scope of Work (SOW) for those facilities as shown in the attached Site Sheets One (1), Two (2), Three (3) and Four (4). Site 1 is the Overhead Electric Distribution System Repairs. Site 2 is the Off Island Crew Support. Site 3 is the Substations, Transmission and Underground Distribution System. Site 4 is the Electric Meter Replacements. Work to be performed at additional sites or expansion of the proposed scope of work will be addressed as outlined below. The applicant has provided actual costs and certified cost estimates from its licensed engineer for the conduct of that work and worked with FEMA to reach agreement on the validated scope and cost. HR – 152; Section 1102; Section 428; (e); (1); (F) notes that "in determining eligible costs under section 406, the Administrator shall, at the applicant's request, consider properly conducted and certified cost estimates prepared by professionally licensed engineers (mutually agreed upon by the Administrator and the applicant), to the extent that such estimates comply with applicable regulations, policy, and guidance."
Hurricane generated storm surge and strong wind caused extensive damage to the power infrastructure throughout the Applicant's four divisions on Long Island, New York, resulting in power outages for approximately 97% of the customer base. Refer to site sheets 1, 2, 3 and 4 for the DDD, SOW and cost enumeration.
Accordingly, at the Applicant's request, the detailed damage descriptions (DDD), eligible scope of work (SOW) and cost estimate as validated by FEMA using the approved sampling methodology contained in Site Sheets One (1), Two (2), Three (3) and Four (4) are hereby aggregated into this fixed, capped PAAP grant Project Worksheet (PW).
The DDD, SOW, and validated cost estimates in those Site Sheets constitute the total eligible scope of work and the maximum funding that FEMA will contribute to the accomplishment of the work under this fixed, capped PAAP grant PW. Once a certified cost estimate is incorporated into a PAAP grant, the value of this cost estimate will not be revisited.
If the Applicant wishes damaged elements or facilities from additional PW to be consolidated into the PAAP grant PW, the certified cost estimates must be provided to FEMA not later than the published deadline. Once validated, an amendment will be issued to the existing capped PAAP grant that will memorialize the Applicant's decision. Again, the amendment process cannot be used to adjust cost estimates incorporated into the original; PAAP or subsequent amendments.
The capped funding is applicable to the approved scope of work identified in this grant. The Applicant has the option to expand the PAAP approved scope of work to include additional improved or alternate projects under the PAAP option. Requests to add additional improved project scope are made to the Grantee. Requests to add additional alternate project scope, which are required to be initiated prior to the

completion of the original PAAP approved scope of work, are reviewed for eligibility by the Grantee and approved by FEMA. Special Considerations Reviews apply to original and any amendments to the scope of work.
The proposed scope submissions (including cost estimates), should be provided as soon as possible and prior to the commencement of the work, to ensure sufficient time to complete required Special Considerations Reviews. This grant incorporates funding for work that has been completed and reviewed through the Public Assistance (PA) program. The PA work completed to date that has been performed under STATEX and CATEX provisions for like-kind repairs or replacements remains eligible. This work has been obligated and reviewed through the FEMA special considerations process. Initiation of construction prior to the completion of the Special Considerations Reviews may jeopardize funding for the Project. FEMA Special Consideration review does not relieve the Applicant of its responsibility for coordination, notification, obtaining permits, and compliance with applicable Federal, State, and local laws and regulations and executive orders.
In the event that the cost to complete the project(s) exceeds the available federal funding in the fixed, capped grant, the applicant must complete the project at its own expense in order to access those federal funds in accordance with the timelines outlined in 44 CFR 206.204 (d)(2).

406 mitigation funding associated with the eligible SOW transferred from the damaged facility PWs has also been aggregated into this PW and its use may be approved on a case-by-case basis. To access these funds, the Applicant must demonstrate, in its request to FEMA, that the risk reduction equals or exceeds that which would have been realized if the mitigation measures in the damaged facility PW were completed. Eligible 406 mitigation measures formulated under standard procedures were included in the PAAP capped grant. To access these funds, the Applicant must demonstrate the measures are consistent with the Hazard Mitigation Proposal included with this PW. The proposal is based on the most vulnerable/repetitively damaged circuits being mitigated, LIPA must document the basis for selecting damage circuits based on historical outages/vulnerability as well as illustrate an estimated 20% reduction in future damages throughout the mainline distribution circuits based on the implemented mitigation measures (a spreadsheet is included in this PW to estimate the percent effectiveness/reduction based on the number of distribution miles strengthened).
As above, approved use of these 406 mitigation funds will be incorporated into the PAAP grant PW through an amendment.
If there are excess funds, the Applicant may request to apply the excess funds to allowable uses, including Hazard Mitigation projects, training and planning activities that improve future permanent work operations, and otherwise-eligible Public Assistance project activities including Improved and Alternate projects. The Applicant will include its proposed SOW tied to the use of the excess funds along with a project timeline for FEMA review and approval through the State. FEMA will de-obligate the excess funds and process a new subgrant defining the proposed SOW and will review it for compliance and EHP laws and regulations. FEMA will evaluate the proposed timeline and document the approved period-of-performance upon approval and obligation of the excess funds subgrant.
Damaged Facility Status In any instance where the damaged facility is itself not being fully restored to its pre-disaster condition, the Applicant must address the disposition of that facility in accordance with FEMA 9525.13, Section VII. 13. The policy requires that if the facility is not repaired, replaced, or sold it must be rendered safe and secure or demolished. Because the cost to secure or demolish such a facility would be included in the aggregated costs transferred to the fixed, capped PAAP grant PW, no additional funding will be provided in the PAAP grant for purpose. The Applicant shall develop a cumulative status list for damaged facilities whose funding has been transferred to the fixed, capped PAAP grant PW to include at minimum: Original PW#, Cost Estimate, facility name (if any), location, disposition of the damaged facility, whether facility was/will be repaired to pre-disaster condition with Applicant's (non-FEMA) funding. If the applicant chooses to repair the damaged facility to its pre-disaster condition using its own funds, the facility may be eligible for assistance in a future declared event.
The applicant has been advised that, except where specifically waived or modified by the Stafford Act, Section 428, compliance with all other law, regulation, policy, and guidance governing the provision of funding under the Public Assistance Program is required.
General Grant Management Requirements
• Applicant is responsible to maintain records that allow FEMA compliance with the reporting and evaluation criterion of the Sandy Recovery Act with respect to hazard mitigation activities in a parallel manner to FEMA approvals
- Applicant shall document as-planned and as-built drawings documenting hazard mitigation scope of work
- Applicant shall document actual costs for hazard mitigation scope of work
• Applicant must complete work within established regulatory time frames and request time extensions as appropriate.
• Applicant must submit quarterly progress reports to the State for large projects in which the work is not completed and financially reconciled.
• Applicant will be reimbursed through the State in accordance with Federal and State requirements.
• Subgrants under alternative procedures are also subject to Strategic Funds Management (SFM), as appropriate, as outlined in guidance for the SFM initiative.
• Applicants must adhere to Federal procurement requirements, as well as other requirements of 44 CFR Part 13, 2 CFR Part 225, and the appropriate Office of Management and Budget circulars.
•The Applicant will comply with EHP requirements, notify FEMA of any work that requires EHP compliance reviews, and provide necessary documentation to conduct EHP reviews. The Grantee shall ensure the Applicant complies with EHP requirements.
• Applicant must not deposit grant funds in an interest-bearing account. If that occurs, the Applicant must remit to FEMA any interest earned.
• Applicant will submit to the Grantee a final report of project costs. This report will not be used for reconciliation of the fixed grant to actual costs, as would normally be required in the standard program. The final report should include the following components: Actual work completed with fixed-grant funds
- Mitigation measures achieved, if applicable
- Compliance with EHP conditions
- Total actual costs to complete the project
- Compliance with Federal procurement procedures
- Actual insurance proceeds received by Applicant

Applicant Long Island Power Authority (LIPA) is a non-profit municipal electric provider that owns the retail electric Transmission and Distribution System on Long Island and provides electric service to more than 1.1 million customers in Nassau and Suffolk counties and the Rockaway Peninsula in Queens. The applicant serves these customers from 171 distribution substations feeding over 900 distribution circuits, consisting of 10,304 miles of overhead and 4,695 miles of underground power lines. During the incident period of Oct 27, 2012 to Nov 8, 2012, hurricane-generated storm surge and strong wind caused extensive damage to the power infrastructure throughout the applicant's four divisions on Long Island, New York, resulting in power outages for over 90% of the customer base. Disaster-related damages occurred when strong winds caused trees and broken limbs to fall into and across overhead electric distribution circuits damaging poles, transformers, power lines, insulators, fuses, and miscellaneous pole structure hardware.

LIPA's four Divisions sustained damages to 827 overhead circuits linked to 149 substations, each of which are connected to and feed multiple electric distribution circuits. The disaster-related damages occurred when strong winds caused trees and broken limbs to fall into and across overhead electric distribution circuits, damaging poles, transformers, power lines, insulators, fuses, and miscellaneous pole structure hardware. To validate the dimensions and quantities of the disaster-related damages to LIPA's overhead electric distribution circuits, the FEMA Public Assistance Team physically inspected 149 circuits (7097 sites) or 17% of 827 overhead distribution circuits to validate the damages. The circuits inspected connect to: 32 substations in the Queens Nassau Division, 33 substations in the Central Nassau Division, 41 substations in the Western Suffolk Division, and 43 substations in the Eastern Suffolk Division. The sample population was taken from applicant-provided downloads of the damage locations (customer call-in reports, visual observation by non-electrical personnel, work orders, etc.) and 1 circuit from each 149 substation was selected for validation. The 17% damage validation did not result in any exceptions (100% positive rate), which provides reasonable assurance at the 95% confidence level (0 deviations) that entire population of damages identified by the Applicant for all 827 overhead circuits were caused by the disaster, not due to applicant negligence/lack of maintenance, were LIPA's legal responsibility, and accurately reported in terms of quantities and scope of damages. The 17% validated by the FEMA Public Assistance Team exceeds the attribute sample population of 60 recommended by the American Institute of Certified Public Accountants (AICPA) in audit standard "AU Section 350, Audit Sampling".

The GPS coordinates identified for this PW are for the LIPA/National Grid offices located at 175 East Old Country Road, Hicksville, NY 11801.

LIPA's four Divisions sustained damages to 827 overhead circuits linked to 149 substations, each of which are connected to and feed multiple overhead electric distribution circuits. Based upon a 17% validation methodology of 149 circuits (1 overhead circuit per substation) involving 7097 sites, the following disaster-damaged items were identified:

1. 4,999 wood poles.
2. 8,136 cross arms.
3. 3,258 transformers of various sizes.
4. 454 miles of conductors.
5. Assorted miscellaneous pole structure hardware and auxiliary overhead distribution components.

SCOPE OF WORK:

PA-02-NY-4085-PW-00367(0):

SITE SHEET 1: CONTRACTOR AND SUBCONTRACTOR OVERHEAD POWER DISTRIBUTION LINE REPAIRS

Work Complete:
Work performed during the operational period of October 26, 2012 through February 13, 2013 by the Applicant to restore the disaster-damaged overhead power distribution line facilities/components to their pre-disaster design, capacity, and function consisted of:

1. Replace 4,999 wood poles damaged beyond repair by the disaster. Replacement work consisted of detaching poles from existing lines, removing any related pole structure hardware and auxiliary overhead distribution equipment. When feasible, reinstall wood poles rather than replace.
2. Replace 8,136 cross arms damaged repair by the disaster. Replacement work consisted of detaching poles from existing lines, removing any related pole structure hardware and auxiliary overhead distribution equipment.
3. Replace 3,258 disaster-damaged transformers with in-kind items.
4. Replace/install 454 miles of conductors.
5. Replace/install assorted miscellaneous pole structure hardware.
6. Dispose of removed items (wood poles, transformers, conductors, miscellaneous pole structure hardware).

To perform storm-related repairs, LIPA brought in 216 off-island line crews to assist with the repair of the damaged utility lines and substations. These crews were contracted through in-place mutual-aid agreements, municipality mutual agreements, contracts with regional power providers and contracts with vendors associated with line repair (environmental and paving). At the time of the disaster, National Grid was under contract with LIPA to maintain its transmission and distribution system under a Management Services Agreement (MSA). Applicant used National Grid's employees to determine the types and extent of repairs for storm damages, manage the off-island crews and inspect the lines and substations once the repairs had been made. National Grid also subcontracted all off-island line crew contractors, environmental contractors, and tree contractors.

Review of Supporting Documentation and Validation

Off-Island Subcontractor Crews: Applicant submitted invoices for subcontractor costs totaling $262,748,450.92. Subcontractor invoices were for mobilization, demobilization, line work, equipment costs or fuel and in some instances meals and lodging for crews eligible for meal and lodging allowances. The Applicant has paid 90% ($236,473,605.83) of these off-island line crew subcontractor invoices. It is their standard accounts payable practices to retain 10% of invoiced amounts until they can complete a full reconciliation of the invoiced costs to address any discrepancies in the invoices. In accordance AICPA "AU Section 350, Audit Sampling", FEMA Project Specialists conducted a validation of the Applicant's paid invoice costs by choosing a randomly selected sample of 60 subcontractor invoices totaling $54,818,507 for both line crews and tree crews costs. The validation resulted in the identification of a 4.59% error rate, or $2,516,219.10 in discrepancies due to incorrect billing rates for mobilization and demobilization, errors in meal reimbursements and errors in lodging reimbursements. This error rate was applied to the 90% invoiced costs paid by the Applicant, resulting in a net amount of $225,619,467.32 covered by this PW. An Amendment (Version) will address the 10% retained amount not covered by this PW upon submission of documentation by the Applicant for this cost and also reconcile any actual additional eligible costs that were excluded from this PW because of the application of the 4.59% error rate.

National Grid Costs: LIPA used National Grid employees to identify the damages, manage the off-island crews and inspect the lines and substations once the repairs had been made. As of the date of this PW (April 9, 2013) the Applicant had not yet provided supporting documentation for National Grid's overhead line repair contract costs, which include to determine the types and extent of repairs for storm damages, manage the off-island crews and inspect the lines and substations once the repairs had been made. These costs will be addressed in a future Version to this PW upon submission of the complete, appropriate supporting documentation by the Applicant.

Sales Tax: The Applicant has a sales tax payment arrangement under its Management Services Agreement (MSA) whereby the New York State sales tax associated with the contractor invoices for off-island line crews is paid by the contractor (National Grid) directly to the state. This cost is then passed by National Grid on to the Applicant for reimbursement. A copy of the Direct Payment permit is attached. Application of a 8.625% New York State sales tax to the validated $225,619,467.32 in off-island crew contract labor cost results in a total of $19,459,679.06. Invoices for National Grid's own employee costs are not subject to New York State sales tax.

Records Retention: Complete records and cost documents for all approved work must be maintained for at least 3 years from the date the last project was completed or from the date final payment was received, whichever is later. Applicant is responsible for retention of all documentation associated with this project.

Procurement: The applicant is required to adhere to State Government Procurement rules and regulations and maintain adequate records to support the basis for all purchasing of goods and materials and contracting services for projects approved under the Public Assistance program, as stated in 44 CFR 13.36. The applicant has advised they have/will follow their normal procurement procedures.

Permits: The PA Project Specialist has advised the Applicant that it is their responsibility to obtain all applicable local, state and federal permits prior to any construction or debris disposal activity referenced on this project. Applicant has also been advised that the lack of obtaining and maintaining these documents may jeopardize funding.

Insurance: The applicant is aware that all projects are subject to an insurance review as stated in 44 C.F.R. Sections 206.252 and 206.253.If applicable an insurance determination will be made either as anticipated proceeds or actual proceeds in accordance with the applicant's insurance policy that may affect the total amount of the project.

Direct Administrative Costs: The Applicant is requesting direct administrative costs that are directly chargeable to this specific project. Associated eligible work is related to the administration of this PA project only and in accordance with 44 CFR 13.22. These costs are treated consistently and uniformly as direct costs in all Federal awards and other subgrantee activities and are not included in any approved indirect cost rates. As of the date of this PW, the Applicant did not have a summary of actual direct administrative costs. An estimated DAC summary is attached. Applicant will be reimbursed for actual, reasonable, documented direct administrative costs that are consistent with the eligible criteria set forth by FEMA Policy DAP9529.9 and the September 8, 2009 FEMA Memo "Disaster Assistance Policy DAP9525.9, Section 324 Management Costs and Direct Administrative Costs and Recovery Policy 9525.14, Grantee Administrative Costs".

Hazard Mitigation Measures: Project was reviewed for 406 Hazard Mitigation and determination is made that mitigation is not feasible.

PA-02-NY-4085-PW-00367(2):

This Amendment 2 is prepared to document the additional expenditures associated with activities performed in the repair of LIPA's overhead electric distribution system. Work associated with the line repair included in the amendment includes linemen, crew guides, line repair inspection, flagging and paving. Environmental work is included in PWs 404 and 2569. Total reimbursable expenditures submitted in this amendment for work completed on subcontractor costs on overhead power distribution line repairs as of 09/17/13 is as follows:
Contract labor to Date-100% liability: $282,410,936.16
Less Contract Labor V0: $225,619,467.32
Less Overpayments: $7,442.18
Validated Contract Labor: $56,784,026.66

Current Version:

Work performed during the operation period of October 26, 2012 thru February 13, 2013 by the Applicant to restore the disaster-damaged facilities to their pre-disaster design, capacity, and function consisted of:

1. Replace 4,999 wood poles damaged beyond repair by the disaster. Replacement work consisted of detaching poles from existing lines, removing any related pole structure hardware and auxiliary overhead distribution equipment. When feasible, reinstall wood poles rather than replace.
2. Replace 8,136 cross arms damaged repair by the disaster. Replacement work consisted of detaching poles from existing lines, removing any related pole structure hardware and auxiliary overhead distribution equipment.
3. Replace 3,258 disaster-damaged transformers with in-kind items.
4. Replace/install 454 miles of conductors.
5. Replace/install assorted miscellaneous pole structure hardware.
6. Dispose of removed items (wood poles, transformers, conductors, miscellaneous pole structure hardware).

To perform storm-related repairs, LIPA brought in over 200 local on-island and off-island line crews to assist with the repair of the damaged utility lines and substations. These crews were contracted through in-place mutual-aid agreements, municipality mutual agreements, contracts with regional power providers, and contracts with vendors associated with line repair (environmental and paving). At the time of the disaster, National Grid was under contract with LIPA to maintain its transmission and distribution system under a Management Services Agreement (MSA). Applicant used National Grid's employees as force account labor to determine the types and extent of repairs for storm damages, manage the off-island crews, and inspect the lines and substations once the repairs had been made. National Grid also subcontracted all off-island line crew contractors, environmental contractors, and tree contractors.

Review of Supporting Documentation and Validation

On and Off-Island Subcontractor Crews: As of 09/17/13, a total of $383,438,986 has been expended on local on island and off island subcontract line and tree crews to aid in the repair of the overhead electric distribution system. Subcontractor invoices were for mobilization, demobilization, line work, line repair inspection, tree removal, flagging, paving, equipment costs or fuel and in some instances meals and lodging for crews eligible for meal and lodging allowances. Applicant's tree crews did not remove or dispose any of the downed

trees.
Environmental work is included in PWs 404 and 2569. In accordance AICPA “AU Section 350, Audit Sampling”, FEMA Project Specialists conducted a validation of the Applicant’s paid invoice costs by choosing a randomly selected sample of 60 contractor invoices for both line crews and off-island tree crew costs. The validation resulted in no errors. Validated costs to date for on and off-island subcontractor crews are $383,438,986.

National Grid Costs: LIPA used National Grid employees to identify the damages, manage the off-island crews and inspect the lines and substations once the repairs had been made. As of the date of this PW (July 15, 2014) the Applicant had not yet provided supporting documentation for National Grid’s overhead line repair contract costs, which include to determine the types and extent of repairs for storm damages, manage the off-island crews and inspect the lines and substations once the repairs had been made. These costs will be sampled and validated upon submission of supporting documentation by the Applicant. Costs incurred for force account labor are 54,749,875.60.

Loadings: In addition to charges for National Grid labor, LIPA is also charged a "loadings rate" on labor for various employee benefits. Components of this employee benefits loading rate include: various retirement benefits such as 401K, pensions, and OPEBS, Group Life Insurance, Health Insurance, Payroll taxes, Paid Time Off, and Worker's compensation, and other. For straight time all loadings components are included in the calculated loadings percentage applied to labor, and for overtime, only those components which are variable with overtime pay are included. Loadings are estimated at $25,184,942.78.

Materials Costs: During the operation period of October 26, 2012 thru February 13, 2013, Applicant set up and utilized six strategically placed major materials staging areas (Green Acres Mall, Nassau Coliseum, Brookhaven Airport, Christopher Morley Park, Rockaway Peninsula and Oyster Bay) to reduce the travel time by line crews to pick up supplies to perform repairs on the damaged lines and substations. Applicant stocked each materials staging area with poles, transformers, cross arms, switches, cables, hardware, etc., and also set up a mobile storeroom at each site. The Applicant provided a listing from their warehousing system of the materials used for the repairs of the applicant’s damages (attached). This materials list was compared against the site inspections information for this PW and appears to be reasonable and consistent with the storm-related overhead power distribution line repairs performed. Applicant’s validated materials costs totaled $17,965,586.90 for materials taken from their existing stockpiles and warehouses to repair the disaster-damaged overhead line distribution components to their pre-disaster design, capacity and function.

Sales Tax: The Applicant has a sales tax payment arrangement under its Management Services Agreement (MSA) whereby the New York State sales tax associated with the contractor invoices for off-island line crews is paid by the contractor (National Grid) directly to the state. This cost is then passed by National Grid on to the Applicant for reimbursement. A copy of the Direct Payment permit is attached. Application of a 8.625% New York State sales tax has been applied to the following validated amounts:

Invoices for National Grid’s own employee costs are not subject to New York State sales tax.

Salvage Value: An estimate of transformer salvage value for this event was not available. Therefore the salvage estimate used for DR-4020 (Hurricane Irene) of $241.58 per transformer is used, as agreed to by the Applicant.

Stores Loading Rate: A Stores Loading Rate of 33% ($5,928,643.48) has been added to the material costs for processing the materials. This is the standard handling cost that the Applicant incurs during normal activities as billed through its Management Services Agreement provider, National Grid.

Force Account Equipment: LIPA will provide detailed backup documentation for force account equipment charges with regards to LIPA's FEMA claim for Sandy. These vehicles are owned (technically leased in some cases) by LIPA. During Sandy, National Grid operated the equipment and maintained records, on behalf of LIPA, to support the dates and run hours that the vehicles were used to make eligible emergency utility repairs caused by the storm. LIPA plans to utilize FEMA's schedule of equipment rates to determine LIPA's eligible force account equipment costs associated with the storm repairs. No estimate of these costs is available at this time.

Fleet Services: National Grid's fleet services department incurred various costs in connection with power restoration, and accordingly invoiced LIPA for these charges. The majority of costs incurred were for fuel purchases. As the availability of fuel was limited, many of the contractors used fuel purchased by Grid for their equipment. Grid also provided wet hosing for equipment parked remotely. Grid used its own employees and contractors for this service. As a replacement for Grid technicians fulfilling other storm assignments, the fleet services department incurred costs for mutual aid technicians to work at Grid garages. The fleet services department also incurred expenses for parts and servicing of equipment damaged in the course of storm restoration.

Applicant Direct Administrative Costs $10,000,000
The Applicant is requesting direct administrative costs that are directly chargeable to this specific project. Associated eligible work is related to the administration of this PA project only and in accordance with 44 CFR 13.22. These costs are treated consistently and uniformly as direct costs in all Federal awards and other subgrantee activities and are not included in any approved indirect cost rates. Applicant will be reimbursed for actual, reasonable, documented direct administrative costs that are consistent with the eligible criteria set forth by FEMA Policy DAP9529.9 and the September 8, 2009 FEMA Memo “Disaster Assistance Policy DAP9525.9, Section 324 Management Costs and Direct Administrative Costs and Recovery Policy 9525.14, Grantee Administrative Costs”. These costs are currently estimated at $10,000,000. As of the date of this PW, the Applicant provided us with documentation for actual costs incurred through April 2014 of $5,908,549.

Site 2 of 4

DAMAGED FACILILITY:	
DAMAGED FACILITY: Off Island Crew Support	COUNTY: Statewide

LOCATION:	LATITUDE:	LONGITUDE:
PA-02-NY-4085-PW-00367(0):	40.76595	-73.51211

System Wide		

DAMAGE DESCRIPTION AND DIMENSIONS:

PA-02-NY-4085-PW-00367(0):

LIPA's four Divisions sustained damages to 877 overhead circuits linked to 149 substations, each of which are connected to and feed multiple overhead electric distribution circuits. Based upon a 17% validation methodology of 149 circuits (1 overhead circuit per substation) involving 7097 sites, the following disaster-damaged items were identified:

1. 4,999 wood poles.
2. 8,136 cross arms.
3. 3,258 transformers of various sizes.
4. 454 miles of conductors.
5. Assorted miscellaneous pole structure hardware and auxiliary overhead distribution components.

The above Lat/Lon coordinates are for the LIPA/National Grid offices located at 175 East Old Country Road, Hicksville, NY 11801.

PA-02-NY-4085-PW-00367(2):

This Amendment 2 is prepared to de-obligate material costs, sales tax paid and stores loading rate associated with material costs that have been included in PWs 404 and 2569 for emergency protective measures.

Current Version:

Version 3 is being written to outline the Section 428 capped grant and to identify the damages and costs associated with the repair work to damaged lines, substations and electric meters. Specific mitigation proposals for damaged circuits and substations will be addressed in future versions.
Applicant Long Island Power Authority (LIPA) is a non-profit municipal electric provider that owns the retail electric Transmission and Distribution System on Long Island and provides electric service to more than 1.1 million customers in Nassau and Suffolk counties and the Rockaway Peninsula in Queens. The applicant serves these customers from 171 distribution substations feeding over 900 distribution circuits, consisting of 10,304 miles of overhead and 4,695 miles of underground power lines. During the incident period of Oct 27, 2012 to Nov 8, 2012, hurricane-generated storm surge and strong wind caused extensive damage to the power infrastructure throughout the applicant's four divisions on Long Island, resulting in power outages for over 90% of the customer base. Disaster-related damages occurred when strong winds caused trees and broken limbs to fall into and across overhead electric distribution circuits damaging poles, transformers, power lines, insulators, fuses, and miscellaneous pole structure hardware.

LIPA's four divisions sustained damages to 827 overhead circuits linked to 149 substations, each of which are connected to and feed multiple electrical distribution circuits. These damages exceeded the capabilities of LIPA's Long Island-based repair workers requiring them to bring in subcontracted line crews and tree removal crews to help with the repair of the damaged utility lines and substations. These crews were contracted through in-place mutual-aid agreements, municipality mutual agreements, contracts with regional power providers, and contracts with vendors associated with line repair (environmental and paving). At the time of the disaster, National Grid was under contract with LIPA to maintain its transmission and distribution system under a Management Services Agreement (MSA).

The sample population provided by the applicant detailed cost summary sheets for each of these categories, which were reviewed and validated by the FEMA Public Assistance Team.

SCOPE OF WORK:

PA-02-NY-4085-PW-00367(0):

Work Complete:

Materials Costs: During the operation period of October 26, 2012 through February 13, 2013, Applicant set up and utilized six strategically placed major materials staging areas (Green Acres Mall, Nassau Coliseum, Brookhaven Airport, Christopher Morley Park, Rockaway Peninsula and Oyster Bay) to reduce the travel time by line crews to pick up supplies to perform repairs on the damaged lines and substations. Applicant stocked each materials staging area with poles, transformers, cross arms, switches, cables, hardware, etc., and also set up a mobile storeroom at each site. The Applicant provided a listing from their warehousing system of the materials used for the repairs of the applicant's damages (attached). This materials list was compared against the site inspections information for this PW and appears to be reasonable and consistent with the storm-related overhead power distribution line repairs performed. Applicant's materials costs totaled $18,261,471.94 for materials taken from their existing stockpiles and warehouses to repair the disaster-damaged overhead line distribution components to their pre-disaster design, capacity and function.

Salvage Value: An estimate of transformer salvage value for this event was not available. Therefore the salvage estimate used for DR-4020 (Hurricane Irene) of $241.58 per transformer is used, as agreed to by the Applicant.

Sales Tax and Stores Loading Rate: The Applicant has a sales tax payment arrangement under its Management Services Agreement (MSA) whereby the New York State sales tax associated with the contractor invoices for off-island line crews is paid by the contractor (National Grid) directly to the state. This cost is then passed by National Grid on to the Applicant for reimbursement. A copy of the Direct Payment permit is attached. Application of a 8.625% New York State sales tax to the validated $18,261,471.94 in materials costs results in a total of $1,575,051.95. In addition, a Stores Loading Rate of 33% ($6,026,285.74) has been added to the material costs for processing the materials. This is the standard handling cost that the Applicant incurs during normal activities as billed through its Management Services Agreement provider, National Grid.

PA-02-NY-4085-PW-00367(2):

This Amendment 2 is to de-obligate material costs that have been included in PWs 404 and 2569 for emergency protective measures in the amount of $419,047.44. Sales tax paid and stores loading rate associated with the material costs are also being de-obligated in the amounts of $25,520.14 and $97,642.26 97

Materials: -$295,885.04
Sales Tax Paid: -25,520.14
Stores Loading Rate: -$97,642.26
Total: -$419,047.44

Current Version:

Work Complete:

Crew Shuttles

Due to lack of secure parking for utility trucks at the hotels and camps housing over 10,000 subcontracted linemen and tree removal crews, the Applicant secured off-site lots as equipment and material staging areas to park the utility trucks and equipment overnight during the time between October 28 - November 28, 2012. The Applicant had five staging areas located at Tanger Mall, SUNY Farmingdale University, Fort Tilden, Bethpage State Park/Restoration Village and parking lots of the former IRS building in Uniondale. Four contracted bus services shuttled workers from these staging areas to the temporary housing locations in six 50-57 passenger coaches.

Review of Supporting Documentation and Validation

Crew Shuttles: Applicant submitted 61 invoices for subcontractor costs totaling $1,136,354.82. FEMA Project Specialists conducted a validation of the Applicant's paid invoice costs by choosing a randomly selected sample of 20% (12) of the invoices totaling $380,974.35 for shuttle services. The validation resulted in no discrepancies. Costs validated for Crew Shuttles are $1,136,354.82.

Temporary Accommodations - Hotels

The Applicant secured accommodations from approximately 150 hotels throughout the Long Island area for subcontracted linemen and tree removal crews for the period of October 27, 2012 to January 26, 2013.

Review of Supporting Documentation and Validation

Hotels: The applicant provided a list of hotel invoices containing 2,435 total transactions, dated 11/3/12 to 1/26/13, with a total cost of $8,227,842. FEMA Project Specialists conducted a validation of the Applicant's paid invoice costs by choosing a randomly selected sample of 20% (485) of the invoices totaling $2,802,148.78 for hotels. The validation resulted in ineligible "no show" costs in the amount of $17,376.28. This error resulted in a less than 1% error rate which is below the accepted 5% error rate. The sample was accepted and the ineligible "no show" costs of $17,376.28 will be deducted from the total submission. No other discrepancies were found. Costs validated for hotels are $8,210,465.72.

Camps and Material Lay Down Sites

The Applicant utilized contract services to assemble, run and disassemble 14 self-contained sleep base camps located at Nassau Coliseum, Suffolk County Community College (Brentwood Campus, Pilgrim, Brookhaven Airport, East Hampton Airport, Bald Hill, Eisenhower Park, Point Lookout Park, Sunken Meadow Park, CW Post University, St. Paul's Recreation Complex, Amityville US Army Reserve, Grumman Studios and 28 fire houses across Long Island. These included bunks, linens, dining tents, catering services, refrigerator trucks, ice, fresh water systems, bathrooms, showers, laundry facilities, dumpsters, portable lights, backup power, heaters, first aid, camp support vehicles with drivers, office trailers, and general support staff. Contract services were also utilized to secure material lay down sites located at Green Acres Mall, Nassau Coliseum, Brookhaven Airport, Christopher Morley Park, Rockaway Peninsula, Oyster Bay, and at multiple substations.

Review of Supporting Documentation and Validation

The applicant has provided a current estimate of $69,844,932. The applicant originally provided a list of invoices (110) with a total cost of $62,682,251.03. FEMA Project Specialists conducted a validation of the Applicant's paid invoice costs by choosing a randomly selected sample of 20% (22) of the invoices totaling $55,277,842 for camps and material lay down sites. The validation resulted in the following ineligible costs: Standby Time ($444,250), Unreturned Linens ($394,820) and 5% administrative costs on standby time and unreturned linens ($41,953.50). This error resulted in a 1.6% error rate which is below the accepted error rate of 5%. The sample was accepted. The total of the ineligible items ($881,023.50) will be deducted from the total submission. No other discrepancies were found in the original sample. Costs validated for Camp and Material Lay Down Sites are $61,801,227.53.

Security

The Applicant employed Doyle Security Services to protect the Applicant and subcontractors' equipment and material located at the material lay down sites. They also patrolled the parking lots of hotels and camps where crews were staying, the material lay down sites, substations and National Grid's parking lots.

Review of Supporting Documentation and Validation

The applicant has provided a current estimate of $181,945. The applicant's original list of invoices totaled $74,426.00. FEMA Project Specialists conducted a validation 100% of the Applicant's original paid invoice costs. No discrepancies were found. Costs validated for Security are $74,426.00.

Additional security costs have been captured in emergency protective measures PWs 404 and 2569.

Crew Meal Costs

LIPA Crew Guides worked with the subcontracted linemen and tree removal crews and Grid's employees in the hardest hit areas of Long Island. In order for crews to restore service as quickly as possible and not have to search for restaurants open in the area, crew guides would secure meals and bring to the crews on site.

Review of Supporting Documentation and Validation

Crew Meal Costs: Applicant submitted a list of invoices crew meal costs and miscellaneous other costs totaling $3,135,478.00. In accordance AICPA "AU Section 350, Audit Sampling", FEMA Project Specialists requested a sample of the Applicant's paid invoice costs by choosing a randomly selected sample of 60 crew guides totaling $239,280.78. The Applicant submitted the supporting documentation on 10/31/13. FEMA Project Specialist has not validated the documentation at this time.

Sales Tax: The Applicant has a sales tax payment arrangement under its Management Services Agreement (MSA) whereby the New York State sales tax associated with the contractor invoices is paid by the contractor (National Grid) directly to the state. This cost is then passed by National Grid on to the Applicant for reimbursement. A copy of the Direct Payment permit is attached. Application of a 8.625% New York State sales tax has been applied to the following validated amounts:

Invoices for National Grid's own employee costs are not subject to New York State sales tax.

Site 3 of 4		
DAMAGED FACILITY: Substations	COUNTY: Statewide	
LOCATION:	LATITUDE: 40.76595	LONGITUDE: -73.51211

DAMAGE DESCRIPTION AND DIMENSIONS:

Current Version:

Version 3 is being written to outline the Section 428 capped grant and to identify the damages and costs associated with the repair work to damaged lines, substations and electric meters. Specific mitigation proposals for damaged circuits and substations will be addressed in future versions.
Applicant Long Island Power Authority (LIPA) is a non-profit municipal electric provider that owns the retail electric Transmission and Distribution System on Long Island and provides electric service to more than 1.1 million customers in Nassau and Suffolk counties and the Rockaway Peninsula in Queens. The applicant serves these customers from 171 distribution substations feeding over 900 distribution circuits, consisting of 10,304 miles of overhead and 4,695 miles of underground power lines. During the incident period of Oct 27, 2012 to Nov 8, 2012, hurricane-generated storm surge and strong wind caused extensive damage to the power infrastructure throughout the applicant's four divisions on Long Island, resulting in power outages for over 90% of the customer base. Disaster-related damages occurred when strong winds caused trees and broken limbs to fall into and across overhead electric distribution circuits damaging poles, transformers, power lines, insulators, fuses, and miscellaneous pole structure hardware.

LIPA's four divisions sustained damages to 827 overhead circuits linked to 149 substations, each of which are connected to and feed multiple electrical distribution circuits. These damages exceeded the capabilities of LIPA's Long Island-based repair workers requiring them to bring in subcontracted line crews and tree removal crews to help with the repair of the damaged utility lines and substations. These crews were contracted through in-place mutual-aid agreements, municipality mutual agreements, contracts with regional power providers, and contracts with vendors associated with line repair (environmental and paving). At the time of the disaster, National Grid was under contract with LIPA to maintain its transmission and distribution system under a Management Services Agreement (MSA).

Twelve substations were inundated with storm surge and salt water flooding. Damages for each substation include the following equipment and additional associated components:

Arverne Substation (40.59252, -73.78358)
- 1- Switchgear
- 7- Breakers
- 7- Breaker Cabinets
- 7- Racking Mech
- 7- Stack Switches
- 8- Breakers
- "x"- Terminal Blocks
- 42- Switchgear Bottles
- 6- Elbows
- 245- Bus Insulation and silver plating
- 21- Epoxy standoff insulators

- 7- Glastic Channels
- 5- PT Drawers
- 7- MOC Switches
- 7- Shutter Assemblies
- 84- CTs
- 15- PTs
- 15- Instrument Transformers
- “x”- Temp Wiring (SIS 14)
- 398- Control and Protection Relay Panel Components
- 2- Distribution panel
- 2- Half line-up of switchgear
- 12- Breakers
- 20 - 3 Cell Batteries
- 1- Battery Charger
- 2- Transformer control cabinets
- 2- CMVs
- 2- Hydran units
- 12- Fans
- 6- Cable surge arrestors
- 1000ftx7ft- Security fence

Atlantic Beach Substation (40.58723, -73.71145)
- 1- Switchgear
- 6- Breakers
- 2- CPTs
- 3- PTs
- “x”- Voltage regulating wiring
- 1- Metal clad switching unit
- 4- Motor operated switches
- 2- Manually operated switches
- 2- Vacuum breakers
- 2- CPTs
- 4- Batteries

Barrett Substation (40.61938, -73.64922)
- 3- PTs
- 3- Half-lineups of switchgear
- 17- Breakers
- 9- Relays
- “x”- Control wiring: transformer bank
- 15- Cooling fans
- 9- Lightning Arrestors
- 1 - Pump
- 21- Bushings
- 1- Globe valve

Captree Substation (40.6456, -73.26043)
- 1- PMH gears (Radio control units)
- 2- Battery charger

Fair Harbor Substation (40.64124, -73.18498)
- 2- CPTs
- 20- Batteries
- 1- Battery charger
- 2- PHMs
- 2- Wireless control sensors

Woodmere Substation (40.63703, -73.73289)
- 1- Switchgear (full lineup)
- 9- Breakers
- 1-RTU cabinet
- 6- Analog Output Module
- 4- Relays
- 2- Control panel Components
- 2- Motor operated mechs
- 1- CPT

Long Beach Substation (40.59392, -73.66196)
- 1- Control House
- 20- Batteries
- 1- Battery charger
- 3- Control panel
- 124- Control Panel Components
- 1- Switchgear
- 4- Motor Mechanisms

- 2- Switchgear Half lineups
- 12- Breakers
- 12- Stack switches
- 1- Ground Switch
- 2- CMV controls
- 1- Tap changer motor
- 2- Desk Chairs
- 1- Office desk

Neponsit Substation (40.56878, -73.86455)
- 1- Metal enclosed ATO switching unit
- 1- Switchgear
- 18- Relay components
- 2- Station transformers
- 4- Cooling fans
- 4- Batteries

Park Place Substation (40.59419, -73.65828)
- 1- Battery Charger
- 20- Batteries
- 1- RTU cabinet
- 4- Control panels
- 12- Fuses
- 12- Fuse Holders
- 3- PTs
- 1- Half lineup of switchgear
- 2- Motor Mechs
- 1- ATO
- 1- CPT
- 1- C&P system
- 1- CMV unit
- 6- CMV Fan
- “x”- Cables
- 10- Spare Breakers
- 2- desk chairs
- 1- Office desk
- 1- A/C unit

Rockaway Beach Substation (40.58281, -73.83422)
- 1-Metal clad switchgear enclosure
- 20-Batteries
- 1-Battery Charger
- 18-Breakers
- 72-CTs
- 18-Stack switches
- 87-Control panel Components
- “x”-Wiring
- 2-Transformer bank tap changer cabinets
- 4-Strip Heaters
- 4-Motor operated switch mechs
- 2-CMV
- 2-Desk chairs
- 1-Office desk

Far Rockaway Substation (40.592541, -73.783219)
- 1-Switchgear
- 9-Breakers
- 54-CTs
- 9-PTs
- 9-Fuses
- 5-Breaker cells
- 24-Breaker bottles
- 9-Control Panels
- 9-Fuse assemblies
- 2-RTU
- 2-Switchgear
- 18-Breakers
- 1-PT Drawer
- 3-PT Fuse
- 1-ATO Switch
- 2-CPTs
- 6-Fuses
- 10-Relays
- 2-Control House
- 52-Fuses

- 6-Relays
- 1-Arbiter Clock
- “x”-Terminal Blocks
- 1-Battery House
- 30-Batteries
- 1-Battery Charger
- 2-Control Cabinets
- 1-Circuit Breaker
- 8-Fan Motor

Ocean Beach Substation (40.64895, -73.1548)
- 2-CPTs
- 20-Batteries
- 1-Battery Charger
- 4-Breakers
- 12-CTs
- 1-RTU
- 2-PMH Wireless Control Sensors

SCOPE OF WORK:

Current Version:

Work Complete:

Arverne Substation (40.59252, -73.78358)
- New Control House and equipment
- 38KV Class Outdoor Switchgear Lineup
- 2- 15KV Class Outdoor Switchgear Lineups
- 2 sets of Replacement Transformer fans and tap changers
- Battery System and SCADA repairs

Atlantic Beach Substation (40.587028, -73.711335)
Damaged equipment at this substation will not be replaced. The substation will be removed from service.
- 1- 5KV Switchgear Lineup
- 1- 15KV Switchgear Lineup
- Battery System

Barrett Substation (40.61938, -73.64922)
- 3-138KV PT's
- 3- 15KV Switchgear Lineups
- 3- Transformer Fan and wiring replacements
- 3 Sets of 138KV Arrestors
- 21- Transformer Bushings
- Transformer pump repair and oil processing

Captree Substation (40.6456, -73.26043)
- 2-23KV PMH Gears
- Battery Charger

Fair Harbor (40.64124, -73.18498)
- 2-30KVA CPT's
- 2- 23KV PMH Gears
- Set of batteries and charger

Woodmere (40.63703, -73.73289)
- 1- Control House
- 15KV Switchgear Lineup
- 2-69KV M.O. Switches

Long Beach (40.59392, -73.66196)
- 1- Control House
- 1- 5KV Switchgear Line Up
- 2- 15KV Switchgear Lineups
- 4- 25KV M.O. Switches
- 1- 69KV Ground Switch
- Transformer tap changer motor and CMV units

Neponsit (40.56878, -73.86455)
Damaged equipment at this substation will not be replaced. The substation will be removed from service.
- 1- 5KV Switchgear Lineup
- 1- 15KV Switchgear ATO
- 4- Transformer Cooling Fans

Park Place (40.59419, -73.65828)
- 1- Control House
- 1- Set of 38KV PT's
- 1- 15KV Lineup

- 2- 38KV M.O. Switches
- 6- Transformer fans and one CMV unit

Rockaway Beach (40.58281, -73.83422)
- 1- Control House C/O:
- 1- 5KV Switchgear Lineup
- 1- 15KV Switchgear Lineup
- 1- Battery System and charger
- 2- Transformer Tap Changers
- 4- 15KV M.O. switches
- 2- Transformer CV units

Far Rockaway (40.592541, -73.783219)
- 1-38KV Lineup
- 4-15KV Line Ups
- 1- Control House
- 1- 69KV Control House
- 1- Battery System and Charger
- 2- Transformer Tap Changers
- 8- Fan Motors
- 1- 69KV Breaker

Ocean Beach (40.64895, -73.1548)
- 2- 75 KVA CPT's
- 1- Battery System and Charger
- 2- 15KV Switchgear Lineups
- 2- RTU's and PMH Sensors

Site 4 of 4

DAMAGED FACILITY: Electric Meter Replacements	COUNTY: Statewide	
LOCATION: PA-02-NY-4085-PW-00367(0): System Wide Current Version: Statewide	LATITUDE: 40.76595	LONGITUDE: -73.51211

DAMAGE DESCRIPTION AND DIMENSIONS:

PA-02-NY-4085-PW-00367(0):

LIPA’s four Divisions sustained damages to 877 overhead circuits linked to 149 substations, each of which are connected to and feed multiple overhead electric distribution circuits. Based upon a 17% validation methodology of 149 circuits (1 overhead circuit per substation) involving 7097 sites, the following disaster-damaged items were identified:

1. 4,999 wood poles.
2. 8,136 cross arms.
3. 3,258 transformers of various sizes.
4. 454 miles of conductors.
5. Assorted miscellaneous pole structure hardware and auxiliary overhead distribution components.

Strong winds generated by the disaster caused trees to fall onto power lines and in public rights of ways, blocking access to the damaged overhead power lines, poles, and transformers. These downed trees needed to be removed so that line crews could safely access work areas and make the necessary repairs to restore the disaster-damaged overhead line distribution components to their pre-disaster design, capacity and function.

The above Lat/Lon coordinates are for the LIPA/National Grid offices located at 175 East Old Country Road, Hicksville, NY 11801.

PA-02-NY-4085-PW-00367(2):

This Amendment 2 is prepared to provide additional reimbursement for activities performed in the repair LIPA’s overhead electric distribution system. As of 09/17/13, a total of $374,679,450.65 has been expended on subcontract line and tree crews to aid in the repair of the overhead electric distribution system. The difference between this updated amount of $374,679,450.65 and the previous expenditure of $305,079,754.20 (as documented in the original PW #00367(0)) is $69,592,254.27is being submitted for reimbursement. The aforementioned differential costs of $69,592,254.27that is addressed in this amendment provides for contract services only; however, sales tax for associated work is also included.

Current Version:

Version 3 is being written to outline the Section 428 capped grant and to identify the damages and costs associated with the repair work to damaged lines, substations and electric meters. Specific mitigation proposals for damaged circuits and substations will be addressed in future versions.
Long Island Power Authority (LIPA) is a non-profit municipal electric provider that owns the retail electric Transmission and Distribution System on Long Island, NY. LIPA provides electric service to more than 1.1 million customers in Nassau and Suffolk counties, and the Rockaway Peninsula in Queens. The applicant serves these customers from 171 distribution substations feeding over 900 distribution circuits, consisting of 10,304 miles of overhead and 4,695 miles of underground power lines. LIPA's system is operated under contract by National Grid ("Grid"), a London-based, for-profit utility operator. Grid manages the day-to-day operations of the utility, including contracting, maintenance, and repairs.

During the incident period of Oct 27, 2012 to Nov 8, 2012, hurricane-generated storm surge and strong wind caused extensive damage to the power infrastructure throughout the applicant's four divisions on Long Island, resulting in power outages for approximately 90% of the customer base. Floodwaters submerged and destroyed a total of 44 commercial and 2,188 residential electric meters in the Rockaways, Fire Island, and other parts of Long Island.

This site sheet consists of 3 geographic areas with the following meter damage identified as storm-damaged beyond repair:

- Fire Island

a. Residential: 2,146 AMR meters
b. Commercial: 42 AMR meters

- Rockaways

a. Residential: 2,556 standard (form 2) meters
b. Commercial: 216 standard meters

- Other areas

a. Residential: 3,424standard (form 2) meters
b. Commercial: 878 standard meters

Damage dimensions for this PW were based on FEMA's review of documentation and material representations by the Applicant to substantiate its claims of damaged meters.

SCOPE OF WORK:

PA-02-NY-4085-PW-00367(0):

Work Complete:

Off-Island Tree Crews: The Applicant brought in 15 off-island tree crews to clear downed trees from the Applicant's power lines and right-of-ways during the operation period of October 26, 2012 through February 13, 2013. The trees were cleared from the electrical overhead distribution system and placed curbside for removal and disposal. Applicant's tree crews did not remove or dispose any of the downed trees.

Applicant submitted invoices for the off-island tree crews totaling $92,536,639.39. The Applicant has paid 90% ($83,282,975.45) of these off-island tree crew contractor invoices. It is their standard accounts payable practices to retain 10% of invoiced amounts until they can complete a full reconciliation of the invoiced costs to address any discrepancies in the invoices. In accordance AICPA "AU Section 350, Audit Sampling", FEMA Project Specialists conducted a validation of the Applicant's paid invoice costs by choosing a randomly selected sample of 60 contractor invoices totaling $54,818,507 for both line crews and off-island tree crews costs. The validation resulted in the identification of a 4.59% error rate, or $2,516,219.10 in discrepancies due to incorrect billing rates for mobilization and demobilization, errors in meal reimbursements and errors in lodging reimbursements. This error rate was applied to the 90% invoiced costs paid by the Applicant, resulting in a net amount of $79,460,286.88 in off-island line crew costs covered by this PW. An Amendment (Version) will address the 10% retained amount not covered by this PW upon submission of documentation by the Applicant for this cost and also reconcile any actual additional eligible costs that were excluded from this PW because of the application of the 4.59% error rate.

Sales Tax: The Applicant has a sales tax payment arrangement under its Management Services Agreement (MSA) whereby the New York State sales tax associated with the contractor invoices for off-island line crews is paid by the contractor (National Grid) directly to the state. This cost is then passed by National Grid on to the Applicant for reimbursement. A copy of the Direct Payment permit is attached. Application of a 8.625% New York State sales tax to the validated $79,460,286.88 in off-island crew contract labor cost results in a total of $6,853,449.74. Invoices for National Grid's own employee costs are not subject to New York State sales tax.

PA-02-NY-4085-PW-00367(2):

This Amendment 2 is prepared to document the additional expenditures associated with activities performed in the repair of LIPA's overhead electric distribution system. Work associated with the line repair included in the amendment includes linemen, crew guides, line repair inspection, flagging and paving. Environmental work is included in PWs 404 and 2569. Total reimbursable expenditures submitted in this amendment for incidental cut and drop tree subcontractor costs for work completed as of 09/17/13 is as follows:
Contract Labor to date-100% Liability: $92,268,514.49
Less: Contract Labor 0: $79,460,286.88
Validated Contract Labor: $12,808,227.61

Current Version:

WORK COMPLETE

Using force account labor (National Grid), the applicant performed the following work to restore the disaster-damaged meters to their pre-disaster design, capacity and function:

1. Fire Island: Remove old meters, dispose of 2,146 AMR residential meters 42 commercial AMR meters, and install 2,146 new residential AMI meters and 42 commercial AMR meters ($182,949 total).
2. Rockaways: Remove old meters, dispose of, and install 2,556 standard-type (Form 2) new residential meters and 216 commercial standard-type meters ($178,758 total).
3. Other areas: Remove old meters, dispose of, and install 3,424 new standard-type (Form 2) meter and 878 commercial standard-type meters ($353,955 total).

Only meters identified in the applicant’s meter retirement records as physically damaged (PD or DAM) or storm damaged (SD) are included on this PW. Prior to the Fire Island breakdown of storm damaged (SD), damaged meters were identified as wear & tear (WT). These meters were replaced due to storm damage of salt water or sand intrusion, however WT was the only manual entry LIPA’s system would allow. Meters identified at planned retirement (PT) are not eligible.

The applicant has standard material and labor costs for meter replacements based on meter type (commercial/ residential, standard/ AMI/ AMR). Installation costs captured in separate PWs as force account labor will be deducted at a later date.

With the exception of a few meters pulled by firemen, storm-damaged meter replacements were initiated with an electronic order for a job assignment, which were dispatched electronically to a field crew, who made the meter replacement. Lists of completed jobs were used to enter new meter numbers into the accounts system. The pulled meters were sent to the shop for recycling and retirement of the physical asset from the system.

Applicant stated there are no associated shop-pulling fees or sales taxes.

Site 1: Fire Island
Following Hurricane Sandy, the applicant opted to replace all AMR meters on the island with AMI meters, regardless of whether they were damaged by the storm.

AMR stands for Automatic Meter Reading. It is an older technology that only collects electrical energy consumption and transfers that data from the electric meter on the home to the utility (one-way communication). AMI stands for Advanced Metering Infrastructure. AMI meters, also known as Smart meters, are updated, digital versions of the traditional electrical meter attached to the outside of a home. These new meters not only measure how much electricity is used, but also at what times during the day. Smart meters are also designed to transmit pricing and energy information from the utility company to the consumer (two-way communication). Utility companies who provide their customers with smart meters are able to implement a variety of load reduction and energy saving programs, helping reduce the cost of providing electricity to a community.
The AMR meters, installed about ten years ago, are still available, and the applicant stated 4/18/13 that the upgrade from AMR to AMI (Smart) meters is not driven by codes and standards.

Additional material costs for the residential AMI meters ($32.50 vs. $87.00) would constitute an improved project, where the applicant will be responsible for any costs above those of the AMR meter type. The old commercial AMR meters are more expensive than the new ones ($800 vs. $285). Installation costs are the same for both AMI and AMR meters ($35 residential, $107 commercial).

a. Residential: 2,146 residential meters on Fire Island were identified by the applicant as disaster-damaged beyond repair, such as broken glass, water intrusion, visible corrosion, or testing outside the 0.5% tolerance of meter accuracy. All meters removed on Fire Island had storm-related retirement codes on the applicant’s detailed breakdown.

Residential AMR meters cost $32.50 each, compared to $87.00 for the new AMI models. In addition, installation costs are a fixed $35 each (about 30 minutes of labor).

b. Commercial: Applicant replaced 42 disaster-damaged AMR commercial meters with AMI meters. Commercial AMR meters cost $800 each, compared to $285 each for the new AMI meters. Installation costs for both types are an additional $107 each (about an hour).

Site 2: Rockaways
All meters in the Rockaways were the Standard type, not AMRs or AMIs.

a. Residential: Applicant has replaced 2,556 standard residential meters due to storm damage as of 4/18/13. Standard residential meters cost $18.50 each. Installation costs are an additional $35 each.

b. Commercial: Applicant has replaced 216 commercial meters as of 4/18/13 due to storm damage.

Site 3: Other Areas (incl. South Shore, Oceanside, Long Beach, and Woodmere)
Applicant stated that only meters damaged by Hurricane Sandy were replaced. Most were identified as damaged during house electrical inspections, which were required before homes were re-energized. All meters in this area were the Standard type, not AMRs or AMIs.

a. Residential: Applicant has replaced 3,424 standard residential meters due to storm damage. Standard residential meters cost $18.50 each. Installation costs are an additional $35 each.

b. Commercial: Applicant has replaced 878 commercial meters due to storm damage. Standard commercial meters cost $87.50 each. Installation costs are an additional $107 each.

NOTES:
Standard Comment 12: Grant Consolidation for Single Fixed Estimate Subgrant: Subgrantee agrees to fund any cost overrun associated with completion of the approved Scope of Work.

Standard Comment 16: Cost Estimate Validation: The Subgrantee provided the estimate for this PW. FEMA validated the estimate and found it to be reasonable for the work to be performed.

Standard Comment 18: De-obligation of Fixed Estimate Subgrant: The Subgrantee has indicated that it wants to transfer this PW to a Consolidated Fixed Estimate PW. PWs 393 and 407 are being deobligated and consolidated into PW 367. Original costs in PW 367 are being deobligated and obligated under the 428 cost codes.

Does the Scope of Work change the pre-disaster conditions at the site? ☐ Yes ☑ No	Special Considerations included? ☑ Yes ☐ No
Hazard Mitigation proposal included? ☑ Yes ☐ No	Is there insurance coverage on this facility? ☑ Yes ☐ No

PROJECT COST

ITEM	CODE	NARRATIVE	QUANTITY/UNIT	UNIT PRICE	COST
1	0000	Work Completed	0/LS	$ 0.00	$ 0.00
2	9003	Contract Costs	1/LS	$ 305,079,754.20	$ 305,079,754.20
3	9009	Material	1/LS	$ 18,261,471.94	$ 18,261,471.94
4	9999	Less Salvage	1/LS	$ -787,067.64	$ -787,067.64
5	9999	Sales Tax Paid IAW Direct Pay Permit (8.625%)	1/LS	$ 27,888,180.75	$ 27,888,180.75
6	9999	Stores Loading Rate	1/LF	$ 6,026,285.74	$ 6,026,285.74
7	9901	Direct Administrative Costs (Subgrantee)	1/LS	$ 5,413.80	$ 5,413.80
		*** Version 2 ***			
		Work Completed			
8	9888	Site 2 Off Island Crew Support Work Completed	1/LS	$ -419,047.44	$ -419,047.44
9	9888	Site 1 Electric Overhead Power Distribution System Work Completed	1/LS	$ 61,681,648.96	$ 61,681,648.96
10	9888	Site 3 Substations Work Completed	1/LS	$ 13,912,937.24	$ 13,912,937.24
		Direct Subgrantee Admin Cost			
11	9901	Direct Administrative Costs (Subgrantee)	1/LS	$ 2,129,329.24	$ 2,129,329.24
		*** Version 3 ***			
		Work Completed			
12	9888	Site 2 Off Island Crew Support Work Completed	1/LS	$ 88,109,039.97	$ 88,109,039.97
13	9888	Site 4 Electric Meter Replacements Work Completed	1/LS	$ 715,662.00	$ 715,662.00
14	9888	Site 3 Substations Work Completed	1/LS	$ 55,087,062.76	$ 55,087,062.76
15	9003	Contract Costs	1/LS	$ -305,079,754.20	$ -305,079,754.20
16	9009	Material	1/LS	$ -18,261,471.94	$ -18,261,471.94
17	9999	Salvage Value	1/LS	$ 787,067.64	$ 787,067.64

18	9999	Sales Tax Paid IAW Direct Pay Permit (8.625%)	1/LS	$ -27,888,180.75	$ -27,888,180.75
19	9901	Direct Administrative Costs (Subgrantee)	1/LS	$ -5,413.80	$ -5,413.80
20	9901	Direct Administrative Costs (Subgrantee)	1/LS	$ -2,129,329.24	$ -2,129,329.24
21	9888	Site 1 Electric Overhead Power Distribution System Work Completed	1/LS	$ 485,420,462.51	$ 485,420,462.51
22	9999	Stores Loading Rate	1/LS	$ -6,026,285.74	$ -6,026,285.74
23	0000	Insurance Adjustments - 5900/5901	0/LS	$ 0.00	$ 0.00
		*** Version 3 ***			
24	5901	Deduct Anticipated Insurance Proceeds	1/LS	$ -24,500,000.00	$ -24,500,000.00
25	0909	Hazard Mitigation Proposal	1/LS	$ 729,695,000.00	$ 729,695,000.00
				TOTAL COST	$ 1,409,702,766.00

PREPARED BY Charlotte Webb	TITLE FEMA Project Specialist	SIGNATURE
APPLICANT REP. Kenneth Kane	TITLE VP of Finance	SIGNATURE

PSEG Long Island
Case Name: PSEG LI - Rate Case 2015
Docket No(s): Matter No. 15-00262

Response to Discovery Request: CITY-0034
Date of Response: 03/26/2015
Witness: CAPITAL BUDGETS

Question:
Please provide a detailed description of PSEG's plan to harden the 69 kV transmission and substation facilities that serve the Rockaways.

Attachments Provided Herewith: 0

Response:
Current plans do not include 69kV transmission and substation facilities that serve the Rockaways.

PSEG Long Island
Case Name: PSEG LI - Rate Case 2015
Docket No(s): Matter No. 15-00262

Response to Discovery Request: CITY-0035
Date of Response: 03/26/2015
Witness: CAPITAL BUDGETS

Question:
Please describe in detail the distribution system storm hardening projects that are planned for the Rockaways.

Attachments Provided Herewith: 0

Response:
Detailed storm hardening projects for the distribution circuits in the Rockaways have not as yet been developed. An engineering and design contractor has been selected and it has begun inspecting the FEMA targeted circuits to identify areas for hardening. This phase of the work will be followed by detailed engineering and design of storm hardening measures. This effort is expected to require several months to complete for all the FEMA targeted circuits in the New York City and Nassau County areas.

While detailed designs are not currently available for any of the distribution circuits in the Rockaways, projects are expected to include all or some of the following types of hardening initiatives:

- Conversion of existing lines to narrower profile designs
- Replacement of smaller poles with stronger and larger poles
- Replacement of existing conductors using conductors with a higher insulation level
- Application of additional Automatic Sectionalizing Switches to reduce the number of customers impacted by mainline faults.

PSEG Long Island
Case Name: PSEG LI - Rate Case 2015
Docket No(s): Matter No. 15-00262

Response to Discovery Request: CITY-0037
Date of Response: 03/27/2015
Witness: CAPITAL BUDGETS

Question:
a. Does PSEG intend to harden distribution circuit mainlines that did not experience an outage event during Superstorm Sandy?
b. If the answer to (a) is in the affirmative, please describe those plans and identify each distribution circuit mainline in the Rockaways that will be hardened.
c. If the answer to (a) is in the negative, please explain why this work is not planned.

Attachments Provided Herewith: 0

Response:

a. PSEG Long Island does not intend to harden any distribution mainlines that did not experience mainline damage during Superstorm Sandy.
b. Not applicable.
c. One of the requirements of the FEMA grant is that such funding can only be utilized to harden facilities that experienced damage during Superstorm Sandy.

PSEG Long Island
Case Name: PSEG LI - Rate Case 2015
Docket No(s): Matter No. 15-00262

Response to Discovery Request: CITY-0039
Date of Response: 03/26/2015
Witness: CAPITAL BUDGETS

Question:
With reference to the Panel's response to City-25, please explain the risk assessment used to prioritize transmission line segments for hardening. Please include in your answer (i) a detailed explanation of the rationale used to define the level of risk that qualifies as "highest risk" for purposes of determining which transmission poles should be upgraded, and (ii) a list of the transmission line segments located in the Rockaways that are, or will be, upgraded.

Attachments Provided Herewith: 0

Response:
None of the transmission lines in the Rockaways experienced damage from Superstorm Sandy; as such none of these lines can be upgraded using FEMA funding.

Segments of transmission lines that experienced damage from Superstorm Sandy will be evaluated for hardening in the areas where damage occurred if significant hazards remain in the area. A typical "high risk" area would be one where tall trees remote from the line, when impacted by hurricane force winds, have the potential to fall on and damage a line.

PSEG Long Island
Case Name: PSEG LI - Rate Case 2015
Docket No(s): Matter No. 15-00262

Response to Discovery Request: CITY-0043
Date of Response: 03/27/2015
Witness: CAPITAL BUDGETS

Question:
a. Did PSEG rely on a climate change model when developing its storm hardening plan?
b. If the answer to (a) is in the affirmative, please identify the model used, and explain how the model projections are reflected in the design elements of the storm hardening plan.
c. If the answer to (a) is in the negative, please explain why PSEG did not consider projections of future climate change when developing its storm hardening plan.

Attachments Provided Herewith: 0

Response:

a. Yes, climate change was considered within the third party study.
b. As part of the third party study, climate change was addressed with respect to sea level change. The study, which was issued in December 2013 considered the best available data from a number of industry sources and recommended an increase of 8 inches due to sea level rise. This recommendation was then used in determining the elevations of critical equipment.
c. NA.

PSEG Long Island
Case Name: PSEG LI - Rate Case 2015
Docket No(s): Matter No. 15-00262

Response to Discovery Request: CITY-0044
Date of Response: 03/30/2015
Witness: CAPITAL BUDGETS

Question:
a. Does PSEG's storm hardening plan reflect any assumptions regarding future sea level rise?
b. If the answer to (a) is in the affirmative, please specify the projected rise in sea level that underlies the storm hardening plan, and identify the source(s) of that projection.
c. If the answer to (a) is in the negative, please explain why PSEG did not consider projections of changes in sea level when developing its storm hardening plan.

Attachments Provided Herewith: 0

Response:

a. Yes, PSEG's storm hardening plan does reflect future sea level rise projections.
b. As part of the third party study, sea level rise was addressed. The study, which was issued in December 2013 considered the best available data from a number of industry sources and recommended an increase of 8 inches due to sea level rise. This recommendation was then used in determining the elevations of critical equipment.

   In addition to increases in equipment elevations to protect against future sea level rise, distribution poles that are replaced as part of the storm hardening plan will be buried a foot deeper than the previous design. This increased depth, as well as installing compacted gravel around buried section of new storm hardened poles, will increase their resistance to strong winds and flooding.

PSEG Long Island
Case Name: PSEG LI - Rate Case 2015
Docket No(s): Matter No. 15-00262

Response to Discovery Request: CITY-0045
Date of Response: 03/26/2015
Witness: CAPITAL BUDGETS

Question:
a. Does PSEG's storm hardening plan reflect any assumptions regarding potential future changes in the frequency and/or intensity of heat waves?
b. If the answer to (a) is in the affirmative, please identify and explain those assumptions, and identify the basis for reliance on same.
c. If the answer to (a) is in the negative, please explain why PSEG did not consider potential future changes in the frequency and/or intensity of heat waves when developing its storm hardening plan.

Attachments Provided Herewith: 0

Response:

a.The FEMA funded storm hardening plan only addresses mitigation of damage from weather conditions from storms that deliver high winds, flooding and other conditions that might be expected from a hurricane or Nor'easter. Therefore, the plan does not reflect any potential changes as a result of heat wave type storms.

b. N/A

c. The FEMA funded program cannot be used to address load related issues that might occur during heat waves and cannot be used to increase power delivery capability. It can only be used to improve resilience of utility facilities to operate during storm conditions. However, the company is also implementing and/or considering other projects, such as T&D and Utility 2.0 investments, that would enhance system reliability. These initiatives are discussed in the direct testimony of the Capital Budget Panel and the Utility 2.0 and Energy Efficiency Panel.

PSEG Long Island
Case Name: PSEG LI - Rate Case 2015
Docket No(s): Matter No. 15-00262

Response to Discovery Request: CITY-0047
Date of Response: 03/30/2015
Witness: CAPITAL BUDGETS

Question:
Did the LIPA service territory experience any shortage in the availability and/or transportation of liquid fuels in the aftermath of Superstorm Sandy? Please explain your answer fully.

Attachments Provided Herewith: 0

Response:

Yes, we did experience a shortage in the availability of fuel during the aftermath of Sandy.

The contracted fuel supplier for Long Island experienced a complete shutdown of its fuel terminals. All of the other suppliers in the area were experiencing the same situation.
We immediately reached out to FEMA for fuel, and contacted a fuel supplier from the Massachusetts area for emergency fuel. The Massachusetts supplier was able to supply all of our fuel for the first few weeks until the FEMA fuel arrived. With a combination of supply from FEMA and this alternate supplier, adequate fuel levels were maintained for several weeks until the local fuel supplier's operation was up and running.

PSEG Long Island
Case Name: PSEG LI - Rate Case 2015
Docket No(s): Matter No. 15-00262

Response to Discovery Request: CITY-0048
Date of Response: 03/25/2015
Witness: CAPITAL BUDGETS

Question:
a. Is PSEG planning to install back-up communications systems on any part of the LIPA transmission or distribution system?
b. If the answer to (a) is in the affirmative, please describe those plans.
c. If the answer to (a) is in the affirmative, please explain why not.

Attachments Provided Herewith: 0

Response:
a. Yes.

b. The communications for SCADA (System Control And Data Acquisition) are necessary to provide real time status and system control. After Superstorm Sandy, copper lease lines used for LIPA SCADA communications were destroyed and not available. In the days following Superstorm Sandy, wireless modems were installed at two substations which are utilizing the modems today. The telecommunications provider has a plan to install fiber lines to replace the copper lease lines that were destroyed. The fiber lease lines are expected to be completed by September 2015 and in 2016. Upon completion, the wireless modems are planned to be used as back-up communications for SCADA.

There are plans (starting with a 2015 Project) to install back-up SCADA communications to the East End of Long Island due to the unreliability of analog copper lease lines. Wireless modems are planned to be installed at several East End substations.

c. n/a

PSEG Long Island
Case Name: PSEG LI - Rate Case 2015
Docket No(s): Matter No. 15-00262

Response to Discovery Request: CITY-0050
Date of Response: 03/30/2015
Witness: CAPITAL BUDGETS

Question:
a. When developing its storm hardening plan, did PSEG consult with other electric transmission and distribution system operators on best practices and design standards for storm hardening?
b. If the answer to (a) is in the affirmative, please identify the entities consulted and specify how the lessons learned from those discussions are reflected in PSEG's storm hardening plan.
c. If the answer to (a) is in the negative, please explain why not.
51. Please explain why the ability to withstand a Category 3 hurricane was chosen as the design standard for the storm hardening program.

Attachments Provided Herewith: 0

Response:
PSEG LI consulted with multiple other electric utilities through the Electric Power Research Institute (EPRI) and participated in their Distribution Grid Resiliency program. EPRI on behalf of their member utilities has tested a number of hardened distribution line designs at their Lennox, MA test facility. The lessons learned from this program have been incorporated in PSEG LI's hardened design for distribution lines and include hardened narrow profile line construction, stronger cross-arms and the use of special reinforcing plates to harden insulators against being pulled out a cross-arm due to a tree or branch impact.

PSEG Long Island
Case Name: PSEG LI - Rate Case 2015
Docket No(s): Matter No. 15-00262

Response to Discovery Request: CITY-0051
Date of Response: 03/30/2015
Witness: CAPITAL BUDGETS

Question:

Please explain why the ability to withstand a Category 3 hurricane was chosen as the design standard for the storm hardening program.

Attachments Provided Herewith: 0

Response:

In October of 2006, LIPA developed and communicated a policy on withstanding severe storms. Within this analysis, there is a reference to the "United States Land falling Hurricane Probability Project" stating; "Experts predict that there is a 73% probability that New York City and Long Island will be hit with a hurricane in the next 50 years, and a 26% probability that it will be a category 3…"

Therefore, 130 mph was chosen as a design standard so that transmission/distribution lines could withstand the highest winds of a Category 3 hurricane. Historically, Long Island's strongest experienced hurricane was a category 3 strength storm (*i.e.*, the 1938 Hurricane). PSEG Long Island agrees that LIPA's existing storm hardening standard of 130 mph is a reasonable standard.

PSEG Long Island
Case Name: PSEG LI - Rate Case 2015
Docket No(s): Matter No. 15-00262

Response to Discovery Request: CITY-0052
Date of Response: 03/30/2015
Witness: CAPITAL BUDGETS

Question:
The Presentation to LIPA's Board Operating Committee ("Board Presentation") appended to the Panel's response to City-002 indicated that LIPA was implementing a 20-year storm hardening plan with a total budget of $500 million. Relative to this Storm Hardening Plan, please provide the following information:
a. the annual budget for each year since program inception;
b. annual expenditures for each year since program inception;
c. a detailed description of the 20-year Storm Hardening Plan that explains the work to be conducted and the design standards that will be applied to that work; and
d. a detailed description of the work completed to date.

Attachments Provided Herewith: 0

Response:

PSEG LI is responding to this data request because, after some deliberation, it was determined although the details are widely dispersed and have not been historically well tracked, there exists within PSEG LI sufficient information to attempt to provide an answer. In responding, please note that we do cite several LIPA documents and reference to LIPA website links, where appropriate.

a. As outlined in LIPA's Electric Resource Plan 2010-2012 Dated February 2010, LIPA targeted spending $500 million over a 20 year period or approximately $25 million per year. This was not a specific level but rather a target value. Please note the rate period at issue in this proceeding is 2016-2018.

See link
http://www.lipower.org/pdfs/company/projects/energyplan10/energyplan10-c.pdf

b. For information on 2013 and 2014 please see response to CITY-002, including its attachments and DPS-TDP-111 (hazardous tree removal). Further though not explicitly part of storm hardening program, the following substations were repaired and storm hardened following Sandy :
    - Arverne Substation 13 kV Switchgear #1 & 2 Replacement
    - Barrett Substation - Replace 1/2 switchgear a/w Bank 7 & 8
    - Rockaway Beach Substation 13 kV #3 & 4 Switchgear

- Far Rockaway Substation 13 kV #7 & 8 Switchgear
- Park Place Substation 13 kV #1 Switchgear
- Woodmere Substation 13 kV #1 &2 Switchgear

Annual storm hardening expenditures were not specifically tracked prior to 2013. However there were several analyses that were performed that estimated expenditures for the period.

Please see attached reports (at shown hyper link) that discuss type of work and estimated expenditures -

- Storm Hardening Talking Points – Board of Trustee Meeting January 2012

http://www.lipower.org/pdfs/company/papers/board/012612-storm.pdf

- Report by Navigant Consultants for LIPA of review of LIPA Capital Investments related to Storm Hardening

http://www.lipower.org/pdfs/company/papers/board/062713-op-storm.pdf

c. With respect to LIPA's Storm Hardening Plan see response to "a" above and response to CITY-002 and CITY-009.

d. The follow lists the type of work completed to date as indicated in the reports mentioned in part b above as well as the CITY-002 response.

- Reconfiguration of substations to avoid equipment damage due to flooding and high wind
- Hardening of substation control houses and outdoor equipment to withstand flooding, high winds and flooding
- Protection of pad mounted equipment and overhead structures against storm surge
- Line Clearance Specification enhanced to achieve greater clearance from trees and branches above wires
- Expanded Distribution Automation system incorporating new switches
- Improve data and voice communications for outage management
- Pilot program to utilize IPads for collection of storm damage
- Trap Bags installed to prevent flooding of vulnerable stations
- Fully upgraded outage management system
- ASU Locations
    - Approximately 65% ASU poles have been hardened
- Replacement of deteriorated poles
- Feeder Exits - exit riser poles have been hardened with larger and stronger poles
- Transmission & Distribution crossings over major roadways have been hardened
- Annual circuit trim and hazardous tree removal programs
    - Cycle is in the process of being reduced from a 5.5 years to a 4 year cycle
    - Removals of hazardous tree / limb conditions annually
- New Transmission Lines
    - All new lines to be designed for Category III Criteria
    - Increased depth of pole for flood zones
    - Steel poles along ROW's

- Steel and Concrete Bases along LIRR Tracks
- Major Road Crossings hardened

- New Substation Installations
  - Avoid Flood Zones or Design appropriate Control Measures
  - Design to Category III Hurricane flood levels
- Major Substation Expansions
  - Design to Category III and Flood Criteria
- Minor Substation Modifications (Failures or Upgrades)
  - Use new Storm Hardened Equipment if Space and Foundations allow
- Purchase of Mobile Substation Equipment

PSEG Long Island
Case Name: PSEG LI - Rate Case 2015
Docket No(s): Matter No. 15-00262

Response to Discovery Request: CITY-0052-b SUPPLLEMENTAL 2
Date of Response: 04/07/2015
Witness: BUDGET

Question:
The Presentation to LIPA's Board Operating Committee ("Board Presentation") appended to the Panel's response to City-002 indicated that LIPA was implementing a 20-year storm hardening plan with a total budget of $500 million. Relative to this Storm Hardening Plan, please provide the following information:
b. annual expenditures for each year since program inception;

Attachments Provided Herewith: 0

Response:
As requested by counsel for the City of New York, PSEG LI is providing the following supplemental information. The equipment damaged by Superstorm Sandy at the referenced substations (see our original response to CITY-52.b) was repaired or replaced. Any equipment that was completely replaced was hardened by means of installation on elevated foundations. Following Superstorm Sandy, the recommended design elevations were based on the higher of the 1-in-100 years plus 2 feet or the 1-in-500 years flood level elevations. The replacement of the Arverne 13kV switchgears was performed immediately after Superstorm Sandy but prior to implementing the updated policy on elevations; therefore, the new elevated foundations' heights at Arverne were designed to be above Sandy flood levels.

PSEG Long Island
Case Name: PSEG LI - Rate Case 2015
Docket No(s): Matter No. 15-00262

Response to Discovery Request: CITY-0058
Date of Response: 03/30/2015
Witness: CAPITAL BUDGETS

Question:
Page 3-46 of the Draft ERP states that all ASU locations will be hardened by 2018.
a. Is this work on schedule for completion by December 31, 2018?
b. If the answer to (a) is in the negative, please explain why not, and state when the work will be completed.
c. How is this project coordinated with the ASU installations that will be reimbursed by FEMA?

Attachments Provided Herewith: 0

Response:
a. The work to harden all ASU locations by 2018 is proceeding on schedule with more than 60% of the switches hardened prior to the start of work on the FEMA circuits.
b. N/A
c. The existing switches located on the 300 circuits which are targeted by the FEMA program will be hardened as part of the program. All new switches installed as part of the FEMA program will be hardened at the time of their installation.

PSEG Long Island
Case Name: PSEG LI - Rate Case 2015
Docket No(s): Matter No. 15-00262

Response to Discovery Request: CITY-0059
Date of Response: 03/30/2015
Witness: CAPITAL BUDGETS

Question:
With reference to the Panel's response to City-31:

a. Please specify the total number of mainline circuits in LIPA's system.
b. Please explain how the 300 mainline circuits identified in response to City-31 were selected for mitigation from among the total population of mainline circuits. Please include in your response an explanation of how a threshold was chosen to separate these two circuit populations.

Attachments Provided Herewith: 0

Response:

a. There are approximately 930 distribution circuits on LIPA's system. Most circuits include both mainline and fused branch line facilities
b. Circuits were selected based on a ranking agreed to between FEMA and LIPA. All circuits were ranked based on total mainline related customer interruption occurring between 1/1/2010 and 12/31/2013. This period includes Hurricanes Irene and Sandy as well as a major Nor'easter in 2010.

The threshold was selected by FEMA but based in part on the expected cost per mile to harden overhead mainline facilities and the level of FEMA funding.

PSEG Long Island
Case Name: PSEG LI - Rate Case 2015
Docket No(s): Matter No. 15-00262

Response to Discovery Request: CITY-0060
Date of Response: 04/06/2015
Witness: CAPITAL BUDGETS

Question:
a. Does PSEG have one or more climate-related metrics (e.g., temperature thresholds) that are tracked and used to inform capital investment and storm hardening decisions?
b. If the answer to (a) is in the affirmative, please specify each such metric and explain how it is used.
c. If the answer to (a) is in the negative, please explain why no such metrics are in use.

Attachments Provided Herewith: 0

Response:
a. Yes.

PSEG has several climate related metrics that are used when considering capital investment and storm hardening decisions. These include temperature/humidity, wind speed, flood level elevations, and ice loading.

b. How each parameter is used to inform capital investment and storm hardening decisions is discussed below:

Temperature/Humidity

Each year, PSEG LI performs a weather normalization of the actual system peak load for the purpose of determining what peak load would have resulted under normal weather conditions. Weather normalized peak loads are used to analyze year-over-year trends in peak load growth without the influence of weather. Normal weather is defined as the average of the actual weather that produced LIPA's system peak loads over the previous thirty years. The normalization process considers the actual daily peak loads and weather conditions from the previous one to three most recent summers, covering June through September, up to 360 observations, to develop a regression model. For those years with sufficiently hot weather, the data from one summer will suffice to develop a valid regression model for weather normalization of the peak load. However, if the weather is mild then the model will include data from prior summers.

The model relates the dependent variable of peak daily load to several weather variables which may include peak hour temperature, peak hour temperature-humidity index (THI) and the 4-, 12- and 24-hour average THI preceding the peak hour, depending upon which among them are shown to be statistically significant. The weather is the average for Kennedy Airport in New

York City, Republic Airport in Farmingdale and McArthur Airport in Islip. Day-type (weekday, Saturday and Sunday) and inter-year category variables may also be used if the model includes data from prior summers. Rainy days are typically removed from the data history and automatic techniques are used to remove outliers. The model is used to determine an adjustment representing the change in load due to the difference between experienced and normal weather which is then added to the actual peak load, resulting in the weather normalized peak load.

In addition, PSEGLI develops a distribution for peak load as a function of the actual temperature and humidity conditions that drove the annual system peak loads for the past 30 years. The base case peak load represents a 50%/50% forecast under weather conditions expected to be reached with a frequency of once in two years, meaning the chances are equal that the peak producing weather will either reach or exceed the base case level. The extreme case peak load represents a 90%/10% forecast under weather conditions expected to be reached only once in ten years. Peak loads corresponding to other frequency levels such as once in five years, once in 20 years or once in 30 years are readily available for analyses as needed.

The resulting load forecast is used to assess the adequacy of the design of the existing and future power system to satisfy customer demand and serves and is the basis for the T&D expansion plan.

Flood Level Elevation

For storm hardening for all Sandy impacted substations, with the exception of the locations on Fire Island, the recommended design elevations for critical equipment are based on the higher of the 1-in-100 years plus 2 feet or the 1-in-500 years flood level elevations. For Fire Island Substations because of the unique topography, the adopted design standard was to protect the substation with flood barriers to a height greater than that experienced during Sandy.

Wind Speed

All new substation infrastructure (including foundations, equipment, transformers, breakers, and control house) and new transmission lines are designed to withstand wind speeds of 130 mph or that of a Category 3 hurricane. All new distribution poles associated at critical transportation crossings, on which Automatic Sectionalizing Units are mounted, or acting as cable riser poles are designed to withstand 130 mph wind speed.

Ice

PSEG LI designs overhead distribution system for 1/2 inch ice load and 40 mph concurrent wind. Transmission facilities are designed for ¾ inch extreme ice load and 50 mph concurrent wind speed.

PSEG Long Island
Case Name: PSEG LI - Rate Case 2015
Docket No(s): Matter No. 15-00262

Response to Discovery Request: CITY-0061
Date of Response: 04/07/2015
Witness: CAPITAL BUDGETS

Question:
Please explain how the electric transmission and distribution systems are being hardened against ice loading associated with ice storms and/or other frozen precipitation.

Attachments Provided Herewith: 0

Response:

The criteria that the LIPA Transmission & Distribution systems follow are outlined in the National Electric Safety Code - Section 25. Among other things, the Code provides the conditions that the Long Island region would experience, as well as the maps associated with the conditions.

The General Loading Requirements for Transmission and Distribution include:

- Paragraph B - Combined Ice and Wind District Loading (Long Island is in the Heavy Loading Zone)
- Paragraph C - Extreme Wind Loading (Long Island is in the 110 and 120 MPH Wind Zone

For structures above 60 feet the following ice and wind loading standard is followed.

- Paragraph D - Extreme Ice with Concurrent Wind Loading

PSEG Long Island
Case Name: PSEG LI - Rate Case 2015
Docket No(s): Matter No. 15-00262

Response to Discovery Request: CITY-0064
Date of Response: 04/10/2015
Witness: CAPITAL BUDGETS

Question:
Please identify each substation that is located in or serves the Rockaway Peninsula. Please specify the number of customers served by each substation, inclusive of the customers served by "downstream" substations.

Attachments Provided Herewith: 0

Response:
There are three substations that serve the load in the Rockaway Peninsula. They are Far Rockaway (18,969 customers), Arverne (6,160 customers), and Rockaway Beach (18,969 customers).

PSEG Long Island
Case Name: PSEG LI - Rate Case 2015
Docket No(s): Matter No. 15-00262

Response to Discovery Request: CITY-0065
Date of Response: 04/10/2015
Witness: CAPITAL BUDGETS

Question:
Please identify each substation that is located in or serves the Rockaway Peninsula that has been retired since January 1, 2013.

Attachments Provided Herewith: 0

Response:
Neponsit was retired in the days following Sandy. All of the load is now being served directly from the Rockaway Beach substation. This is not additional load to Rockaway Beach as Neponsit was a 13kv/4kv unit substation that was fed from Rockaway Beach 13kv.

No other stations have been retired in the Rockways.

PSEG Long Island
Case Name: PSEG LI - Rate Case 2015
Docket No(s): Matter No. 15-00262

Response to Discovery Request: CITY-0067
Date of Response: 04/15/2015
Witness: CAPITAL BUDGETS

Question:
Please provide the analysis referenced in response to City-51.

Attachments Provided Herewith: 1
LIPA_Withstanding_Severe_Storms_Oct_2006 - Confidential.pdf

Response:
City-51 references the October of 2006 LIPA report. It is being provided to the DPS Records Access Officer with a request for confidential treatment because the report contains confidential intra-agency deliberative information.

May 6, 2015

VIA ELECTRONIC FILING

Donna Giliberto, Esq.
Records Access Officer
New York State Department of Public Service
3 Empire State Plaza
Albany, New York 12223-1350

Re: Request for Withdrawal of Confidentiality
PSEG LI – Rate Case 2015
Matter No. 15-00262

Dear Ms. Giliberto:

On April 15, 2015, PSEG Long Island LLC ("PSEG LI") requested confidential treatment for the following report requested by the City of New York in Discovery Request No. 67:

LIPA, Withstanding Severe Storms, Policy and Program Summary, October 17, 2006.

After further consultation with the Long Island Power Authority, PSEG LI is withdrawing this request for confidential treatment.

Respectfully submitted,

Robert G. Grassi
Associate General Regulatory Counsel

cc: Hon. Michelle L. Phillips, Administrative Law Judge (w/out attachment)
Hon. David R. Van Ort, Administrative Law Judge (w/out attachment)
Guy Mazza, Assistant Counsel (w/out attachment)

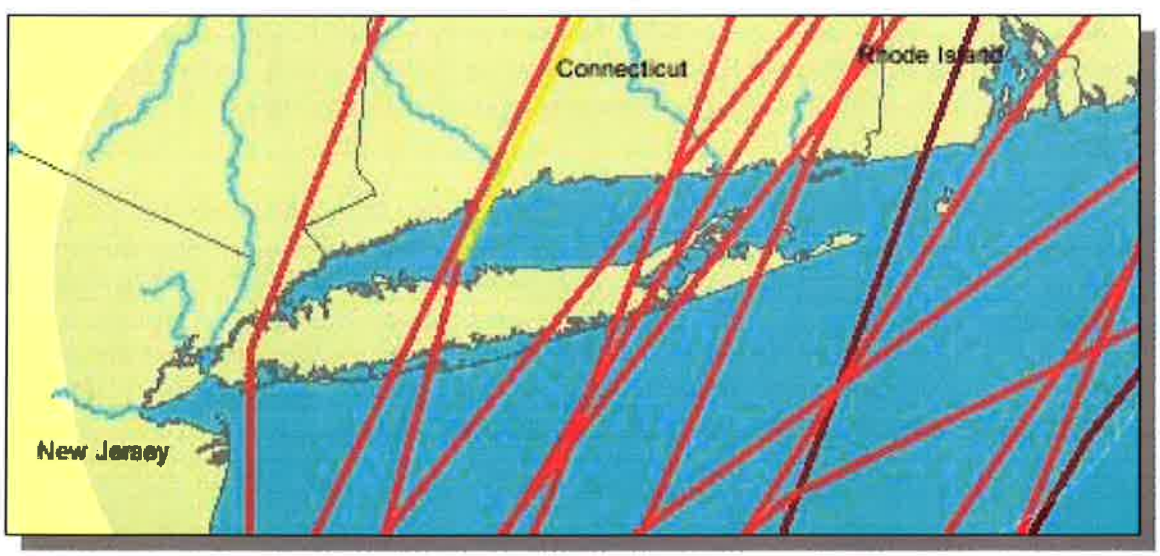
LIPA

Long Island Power Authority

Withstanding Severe Storms

Policy and Program Summary

October 17, 2006



LIPA is Committed to Strengthening It's System to Withstand Severe Storms

Severe storms pose a high risk to Long Island's electric power system. For example, in the wake of hurricane Gloria in 1985, 750,000 customers on Long Island lost power for periods up to two weeks. Recognizing this threat, LIPA has adopted a proactive policy to address the threat of severe storms and has launched a long-term program anticipated to cost up to $500 million to improve the capability of the electric system on Long Island to withstand the impacts of hurricanes and other severe storms, and to shorten the time required to restore service to customers when outages occur due to storms.

LIPA's policy incorporates three main thrusts: 1) improve the ability to withstand severe storms without damage (durability); 2) improve the ability to continue service despite some system damage (resilience); and 3) reduce the time necessary to recovery when service is disrupted (restoration). LIPA's policy is targeted at impacts of major hurricanes, not just routine storms. Although hurricanes occur relatively infrequently, LIPA must be prepared to operate its electric power system during these severe storm events and restore service quickly in the event of damage. In this regard, LIPA's severe storm policy recognizes that the additional costs to LIPA help to counter the potentially disastrous impact on the Long Island community from hurricanes. No program can assure that severe storms will not cause power outages, but LIPA believes that implementation of its policy will both reduce the degree of damage and enable faster restoration when outages do occur.

To implement this policy, LIPA has directed its staff and system management contractor to develop a detailed program targeted to achieve improvements in the areas of system durability, resilience and restoration. A program comprised of 15 key initiatives is under review. Certain of the initiatives will expand on actions already underway or under consideration by LIPA, while others are new. Details of these initiatives are described below.

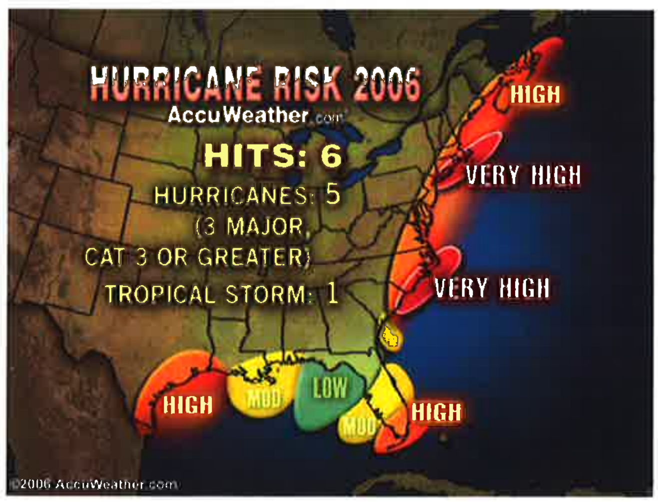
Implementation of the program will begin immediately. Initial activities will center on continuation of several initiatives currently underway, along with engineering studies and design changes necessary to evaluate and implement other initiatives. LIPA anticipates that it will take up to 20 years to complete all program initiatives. Throughout this period, LIPA will monitor the experience of the utility industry for lessons learned from major storms and for improvements in materials and techniques that will allow quicker, more effective implementation of LIPA's severe storm program.

LIPA's System is Vulnerable to Severe Storms

Long Island experiences numerous storms each year. In most instances the related electric power system damage and customer service outages are limited. However, hurricanes in the southern U.S. in 2005 amply illustrated the extensive damage to electric power systems and other facilities that can be wreaked by a severe storm. Although it has been 15 years since the last hurricane struck Long Island (Hurricane Bob in 1991), hurricanes struck on average about once every four years in the 20 years prior to that. In fact, LIPA's system is located in an area of the U.S. most prone to hurricanes (see AccuWeather illustration below). Experts predict that there is a 73% probability that New York City and Long Island will be hit with a hurricane in the next 50 years, and a 26% probability that it will be a category 3 or greater intensity.[1]

Hurricane intensity is rated on a scale from 1 to 5. A category 1 hurricane (the weakest) has sustained winds of 74-95 mph and storm surge of 4-5 feet above normal.[2] Long Island's topography is generally low lying and the storm surge from a category 1 hurricane could cause flooding of much of the south shore and the both sides of the north and south forks.

A category 3 hurricane has sustained winds of 111-130 mph and a storm surge of 9-12 feet above normal. This could result in extensive flooding along the south shore, covering Montauk Highway (route 27A), and inundating the north and south forks.



Extensive flooding would hamper LIPA's restoration efforts as well as those of other emergency response organizations. Saltwater flooding would likely destroy some of LIPA's equipment and facilities and render other equipment unusable until it had been thoroughly cleaned and inspected.

In addition to the damage caused by flooding, hurricane force winds would be the cause of significant damage to LIPA's electrical system.[3] Power industry experience, including on Long Island, shows that

[1] United States Landfalling Hurricane Probability Project (www.e-transit.org/hurricane/).

[2] Storm surge is a dome of water 40 to 60 miles long that moves onto the shoreline near the landfall point of the eye of a hurricane. A cubic yard of sea water weighs approximately 1,700 pounds. As this water is constantly slamming into shoreline structures, even well-built structures quickly get demolished. As the waters move inland, more debris floats along with it causing further damage. Storm surge is responsible for nearly 90% of all hurricane-related deaths and injuries. (S. Mandia, "The Long Island Express--the Great Hurricane of 1938").

[3] The power of wind increases with the cube of the wind speed, therefore a category 3 hurricane would have about three times the force of a category 1 hurricane.

downed trees and flying debris are the reason for most storm outages. The table below summarizes electric system damage from the most recent five hurricanes to impact Long Island. Note the numbers of locations where wires were down (broken)—damage that is typically caused by trees and debris.[4] Also note that while in each case there were hundreds of damaged poles, in every case these were only a very small fraction of the total poles in the system (approximately 600,000).[5]

Summary of Hurricane Damage to the Long Island Electric System

	Doria 1971	Felix 1973	Belle 1976	Gloria 1985	Bob 1991
Hurricane Category			1	1	2
Wind Speed (mph)			95*	90	>100
Transmission Outages	14	8	46	107	49
Substation Outages	25	N/A	32	85	29
Distribution Outages	169	177	203	478	129
Primary Wire Down Locations	1,558	3,161	2,173	4,132	3,078
Poles Damaged	202	259	326	1,252	301
Customers Affected	350,000	327,000	533,000	750,000	380,000

Source: LIPA (LILCO) reports.
Hurricane categories and wind speeds are as of the time of impact on Long Island. Although Hurricane Gloria was a category 1 hurricane, its rapid forward movement resulted in wind speeds to the east of the eye in excess of 110 mph.

Transmission and substation outages, although few in number, have the potential to disrupt service to many customers and may also require significant time to repair. Even underground equipment is subject to washout in coastal and flooded areas, as well as damage due to corrosion from saltwater.

Communication and control systems are also a concern. The resilience of the system to withstand damage and continue to operate, and the effectiveness of restoration efforts would be adversely impacted by damage to communication and control systems.

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[4] Given the vulnerability of overhead lines to storm damage, undergrounding lines is one way to protect the system from severe storm damage. Approximately one-third of LIPA's existing distribution lines are underground. However, extensive undergrounding of existing overhead lines is not the best plan for LIPA. A study completed for LIPA in 2005 concluded, "Burying existing overhead power lines does not completely protect consumers from storm related power outages. During storms, conditions such as flooding, objects falling on surface mounted equipment, and over-voltages caused by lightning can cause the loss of power on underground systems. Moreover, long-term system outages such as those associated with major storms may allow moisture to seep in, and this moisture can cause the cable to fail once the system is re-energized." The report also indicates that restoration time for underground lines is typically much longer than for overhead lines, burying lines would be disruptive in the affected areas and require a major increase in electric rates. For these reasons, LIPA's program incorporates selective undergrounding where conditions warrant, along with a variety of other initiatives intended to benefit LIPA customers.

[5] Approximately half of these poles are owned by Verizon, the local telephone company. LIPA and Verizon have a "joint-use" agreement that allows each company to install its wires on the poles owned by the other company.

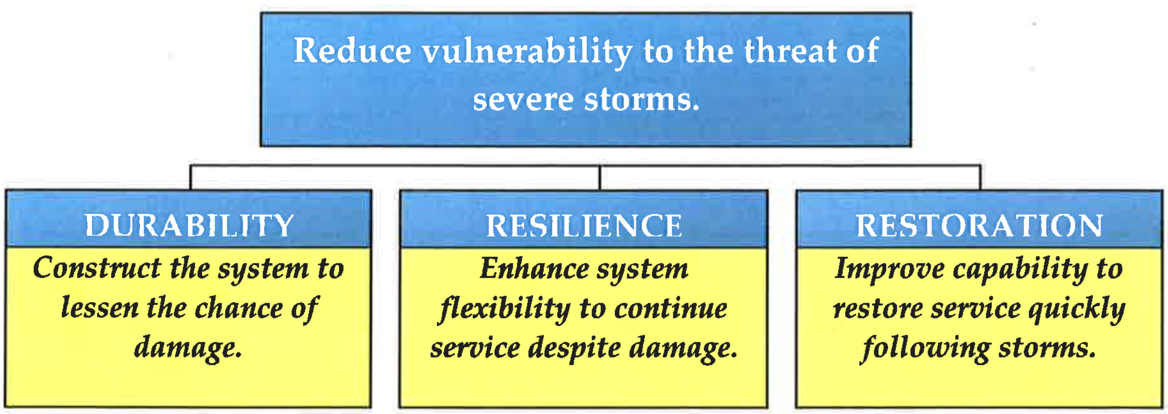
LIPA owns the transmission and distribution system (poles and wires) on Long Island. Service to customers may also be affected by damage to facilities owned by others. These include the telephone company poles noted above, generating stations (many of which are located on coastal sites), and major interconnections to other power systems. LIPA will work closely with those organizations to ensure that adequate programs are in place to protect these facilities from severe storm damage and to restore these systems in the event of damage.

Policy Basis

Considering the areas of vulnerability to Long Island's electric power system, LIPA has adopted a three-pronged approach to development of its storm hardening policy with emphasis on durability, resilience and restoration.

At the frontline of storm protection, *durability* is the ability to withstand the impacts of storms without damage. Durability includes materials or equipment that resist damage; the arrangement of existing equipment to resist or avoid damage; and technologies that help protect the system from damage. LIPA is already accomplishing much in this area and will continue and enhance existing system improvement programs. Nevertheless, a review of the experience on Long Island, Florida and elsewhere suggests there are additional effective measures that should be deployed by LIPA. Also, new materials and equipment are available that offer the opportunity for improved durability to storm damage.

Basis for LIPA's Policy



Whereas durability is the ability to withstand the stresses of storms without damage, *resilience* is the ability to continue to operate despite damage to some parts of the system. Resilience deals with the configuration of system components to reduce the numbers of outages; reconfiguration of the system to maintain service; and application of resources to continue service to customers while the electric system is restored. LIPA is already recognized as a leader in the deployment of equipment that isolates damaged portions of the system while automatically restoring service to the undamaged parts. This is one of the reasons that LIPA has the best record in New York State for the smallest overall average numbers of outages per customer and shortest duration of outages when they do occur.

Unfortunately, no amount of preparation can assure that power outages will not occur as the result of storms. But when outages do occur, *restoration* is the process of repairing damage and getting electric service back to affected customers. Restoration encompasses means to improve the system to facilitate quicker restoration; the effective application of resources to get the lights back on; and improvement in operations to reduce restoration time.

LIPA's Severe Storm Policy

In the interest of preserving the safety, health, economy, comfort and convenience of the Long Island community at large, LIPA has adopted a policy to guide the development and implementation of a long-term program necessary to improve the ability to withstand severe storms. This policy consists of the following:

1. Improve the ability of the Long Island electric power system to withstand severe storms without damage (durability);
2. Improve the ability of the Long Island electric power system to continue service despite some system damage (resilience);
3. Implement changes aimed at reducing the time necessary to recovery when service is disrupted (restoration);
4. Such improvements shall be based on the occurrence of a category 3 hurricane striking Long Island;
5. The changes contemplated shall include both operating and maintenance practices and long-term capital improvements to be implemented over a period of at least 20 years;
6. Program initiatives adopted as a result of this policy shall consider the potential impact of a hurricane on the community at large and the potential effects of the loss of electric power on a priority basis within the community (safety, health, economy, comfort and convenience); and
7. LIPA shall monitor and adopt (as appropriate) lessons learned from storms affecting other areas, as well as industry improvements in facility design, construction techniques, materials and other practices.

LIPA directs its staff to report annually on the development and implementation of the severe storm program adopted as a result of this policy.

Program Elements

LIPA's severe storm program consists of 15 key initiatives identified to best accomplish the three major storm policy goals. The specific initiatives comprising LIPA's severe storm program are subject to change depending on review and analysis of the details of specific initiatives, detailed review of vulnerable facilities, and design considerations to mitigate the most vulnerable situations. Note that some of these initiatives represent a continuation or expansion of LIPA's current practices.

Durability: Construct the system to lessen the chance of damage.

1. Reconfigure or reconstruct substations to avoid damage from flooding and wind. Substations are facilities that transfer power among the lines comprising the electric power grid. Damage to substations can affect numerous customers and require a long time to repair. This initiative will focus on the substations most vulnerable to flooding and equipment within substations most vulnerable to damage from high winds and debris. New substations will be constructed with these improvements in place. Priority will be given to substations most critical to the operation of LIPA's transmission system to maintain supply to unaffected customers and help restore supply to affected customers.
   a. Reconfigure substations to avoid equipment damage during flooding:
      - Raise equipment foundations (switchgear, control panels, batteries).
      - Tie down equipment and structures, particularly that which could float when flooded.
      - Replace distribution air circuit breakers with vacuum circuit breakers that can better withstand contact with salt water.
      - Modify design standards for substations in low lying areas.
      - Rebuild substations with flood-resistant design.
   b. Reconfigure substations to avoid equipment damage from high winds:
      - Modify fences to withstand high winds and protect against flying debris.
      - Replace 69 kV circuit breaker bushings with bushings that can withstand higher winds (130mph instead of 90mph).
      - Secure structures, trailers and other miscellaneous equipment in substation yard.
      - Modify standards and equipment designs to withstand 130 mph wind.
      - Adopt a "clean yard" policy (e.g., don't store spare parts, equipment and other material at substations).
   c. Harden substation control houses and outdoor control equipment to withstand high winds, rain, and flooding:

- Strengthen roofs to withstand wind
- Install hurricane shutters on windows
- Install tie-down straps on control houses
- Prevent intrusion of wind-driven rain from coming in under doors or through vents
- Review external battery sheds for vulnerabilities and install rain intrusion restriction on vents
- Seal control cable conduit
- Standardize on NEMA 4 enclosures for outdoor control equipment and replace existing enclosures
- Adopt hurricane resistant design for control houses

2. Improve transmission line design and construction to withstand high winds. Transmission lines are the high voltage lines that serve as the "backbone" of the electric power grid. It is necessary to maintain the operation of the transmission lines to allow power to flow to the local distribution lines that serve customers. This initiative incorporates enhanced inspection practices for overhead transmission structures, expanded tree trimming, changes in design and construction to reduce the chance of storm damage, and selective undergrounding of lines outside the surge and flood zones that are most vulnerable to wind damage and where no other transmission line is available to serve the area. Priority attention will be given to lines comprising LIPA's main power corridors, lines that are the only supply source to distribution substations, and other lines that are critical to continuity of supply and restoration in the event of system damage.

   a. Strengthen overhead transmission lines to withstand high winds:

      - Replace 69 kV and 33 kV wood structures with high strength poles in heavily treed areas and on rear property.
      - Upgrade crossarms to withstand higher loads.
      - Replace porcelain insulators with polymer insulators to avoid damage from flying debris.
      - Standardize on high strength poles in more applications, including the reinforcement of major roadway crossings, to prevent downed wires in roadways.
      - Adopt the NESC "Extreme Wind" criteria for transmission (or greater if necessary).

   b. Reduce the impact of tree contact on 69kV and lower voltage transmission lines:

      - Expand clearance beyond 18 feet on non-ROW lines, including removal of large trees at the edge of the clearance zone that may topple.

- Expand the "wire friendly tree" program.
- Apply aerial cable construction to roadside transmission lines at 33 kV and below in heavily treed areas.
- Consider undergrounding roadside transmission in heavily treed areas where line clearance or compact/spacer construction is impractical and other alternatives are not available due to technical reasons.

c. Inspect and replace inadequate poles and equipment:

- Adopt common utility practice in the structure inspection program to cover both physical condition and joint use attachments (with focus on joint use attachments on 69 kV lines). This will include pole attachment policies and design standards, as well as the physical inspection approach.
- Replace poles that are not up to new standards regardless of condition in addition to those found to be in inadequate condition (the current practice).

d. Seek innovative alternative solutions to protection of existing and new underground lines in flood and surge zones where underground lines may be subject to damage from washout.

3. Improve distribution design and construction to withstand high winds. Distribution lines serve the local neighborhoods. Many of these lines are constructed on poles and are susceptible to damage from wind. To address this vulnerability, this initiative includes enhanced vegetation management, and design changes to mitigate potential storm damage from high winds and flooding.

a. Reduce the impact of tree contact on distribution lines:

- Expand clearance beyond 18 feet on distribution, including removal of large trees at the edge of the clearance zone that may topple.
- Expand "wire friendly tree" program.
- Apply spacer cable construction to distribution in heavily treed areas.
- Uniformly adopt Class B construction standards.
- Apply selective undergrounding to distribution in heavily treed areas where Class B construction, line clearance, or compact/spacer construction is impractical. Underground standards should be modified to cope with or protect against flooding in coastal areas.

b. Seek innovative alternative solutions to protection of existing and new underground lines in flood and surge zones where underground lines may be subject to damage from washout.

c. Inspect and replace inadequate poles and equipment:

- Enhance the pole inspection program to cover both physical condition and joint use attachments. This should include attachment policies and design standards, as well as the physical inspection approach.
- Replace poles that are not up to new standards regardless of condition in addition to those found to be in inadequate condition (the current practice). Priority will be given to those poles that support distribution automation system equipment that also enhances system resiliency and restoration capabilities.

d. Protect distribution equipment from storm surge damage:

- Harden pad-mounted equipment by tying it down or fastening it to robust foundations. As part of hardening, flag the equipment so it can be identified among storm surge debris.
- Review and modify, as appropriate, the design standards for construction in areas potentially affected by storm surge, including consideration of submersible equipment in some instances.

***Resilience*: Enhance the system flexibility to continue service despite damage.**

4. Leverage LIPA's leading distribution automation system to manage the scope of outages, and speed reconfiguration and restoration. Distribution automation refers to equipment designed to allow automatic (or remote) switching of lines that would reduce the time that lines are out of service and allow for continued supply to undamaged portions while damaged portions are being repaired.

   a. Upgrade circuit reclosers so that reclose/lockout settings can be changed remotely/automatically.

   b. Ensure that distribution automation is a centerpiece of LIPA distribution planning, design and standards; expand automation to primary branch circuits:

      - Ensure that distribution automation devices and equipment are protected as highest priority items on the distribution system
      - Take advantage of distribution circuit upgrades to ensure that circuits can be fed from multiple locations in the event of outages

5. Employ Distributed Generation and Microgrids. Consider the incorporation of distributed generation and microgrids (small customer networks) in distribution planning and design over time. LIPA uses mobile generators to provide for temporary supply in certain extreme cases, and is already experimenting with distributed generation.

***Restoration**: Reduce the time needed to restore service following storms.*

6. Proactively De-energize Circuits. Investigate the value of de-energizing circuits before storms hit to reduce damage from high winds and flooding. Although this may seem counter to the goal of maintaining electricity service, in some instances extended outages may be avoided if equipment is turned off before a storm, inspected and cleaned after the storm, then turned back on.
7. Outage Management. Upgrade the outage management software system currently used to allow for automatic links to geographic information and other systems.
8. Improve Voice and Data Communication Channels. Improving the availability, capacity, and reliability of communications among LIPA, contractors and foreign crews increases the efficiency and effectiveness of the restoration processes.
   a. Improve data communication channels for substations.
   b. Invest in mobile communication towers.
   c. Provide common voice/data communication among LIPA, contractor, foreign crews, and other utility and emergency response organizations.
   d. Pre-deploy communication facilities to staging and receiving sites
   e. Implement mobile communication center to accommodate local restoration needs and mitigate damage to fixed base systems.
9. Implement a resource control system. An important part of the restoration effort involves tracking all restoration personnel, crew vehicles, and critical equipment. This is especially important because of the common practice of using repair crews from other utilities and contractors with thousands of temporary workers.
   a. Deploy an automatic vehicle location system (GPS, global positioning system) for all restoration crew vehicles.
   b. Leverage LIPA's geographic information system to GPS coordinates to more effectively communicate damage location to crews and other emergency response organizations.
   c. Implement a resources control system to track all restoration personnel (including foreign and contractor crews), and critical equipment:
      - Implement a computer readable identification card system and deploy to all restoration sites.
      - Implement a bar code or RFID (radio frequency identification) inventory control to track equipment issued to crews for each work order.
10. Implement an electronic damage inventory system. Damage inventory is critical to the restoration process. Efficient procurement and allocation of resources and material depends on quick and accurate damage inventory.
11. Improve damage assessment processes. Accurate data on actual damage will result in quicker restoration.

a. Contract for post-storm aerial patrols by helicopter for transmission lines and remote distribution facilities.

b. Develop specific plans and criteria for these aerial patrols.

c. Implement a quick initial damage assessment plan using pre-planned survey routes for personnel commuting from their homes to assigned locations.

12. Improve the restoration management system. Quick and efficient access to information is essential to decision making, and to the prosecution of the restoration plan.

    a. Automate reports (e.g., switching status).

    b. Improve the restoration system user interface.

    c. Integrate databases to facilitate the access to information.

    d. Implement an electronic completion system for work tickets. (This initiative is currently underway.)

    e. Use IVR to confirm that customer power has been restored. (This initiative is currently underway)

    f. Automate the tracking of system element performance in storm conditions.

13. Improve restoration logistics processes. Efficient logistics improves productivity of restoration personnel and other resources.

    a. Structure the logistics processes to minimize field crews unproductive time (e.g., provisioning the trucks in the evenings, delivering major equipment to job sites, procuring crew lodging near staging site).

    b. Deploy auditors to monitor crews and materials during restoration.

    c. Incorporate receiving (off island foreign crew processing center) and staging site into the logistics process. (This initiative is currently under investigation.)

14. Develop human resources support to ensure employee commitment to the restoration effort. A strong turn-out of restoration personnel is critical once the storm has passed. Anticipating employees' housing and family emergencies improves turn-out immediately following the storm and enhances their commitment to the restoration effort. (This initiative is currently underway.) This includes initiatives such as:

    a. Provide shelter for displaced employees and their families.

    b. Arrange temporary daycare for employee children and elderly dependents.

    c. Stockpile materials that employees could use for temporary repairs to their homes

15. Insure effective contractor response. A strong turn-out of contractors who provide essential services is critical during the initial stages of the restoration process. Among the methods of ensuring needed turn-out is to modify contracts to include incentives and penalties for contractor storm response.

PSEG Long Island
Case Name: PSEG LI - Rate Case 2015
Docket No(s): Matter No. 15-00262

Response to Discovery Request: CITY-0068
Date of Response: 04/14/2015
Witness: CAPITAL BUDGETS

Question:
With reference to the Report by Navigant Consultants appended to the Panel's response to City-52, please provide the 2006 Navigant storm hardening report referenced on page 6.

Attachments Provided Herewith: 1
Storm_Hardening_Initiative_Navigane_Draft_July_2006 - CONFIDENTIAL.pdf

Response:
In response to City-52 there was a reference on page 6 in the 2013 Navigant Report http://www.lipower.org/pdfs/company/papers/board/062713-op-storm.pdf to a 2006 Navigant Report. A confidential draft version of that report was found in legacy files. This was confidential to LIPA, and it is unknown if Navigant ever provided a final version to LIPA. We are providing a copy of the report to only the DPS Records Access Officer with a request for confidential treatment (as the report contains intra-agency deliberative material) and to counsel for the City of New York subject to our nondisclosure agreement.

PSEG LONG ISLAND
We make things work for you.

May 6, 2015

VIA ELECTRONIC FILING

Donna Giliberto, Esq.
Records Access Officer
New York State Department of Public Service
3 Empire State Plaza
Albany, New York 12223-1350

Re: Request for Withdrawal of Confidentiality
PSEG LI – Rate Case 2015
Matter No. 15-00262

Dear Ms. Giliberto:

On April 15, 2015, PSEG Long Island LLC ("PSEG LI") requested confidential treatment for the following report requested by the City of New York in Discovery Request No. 68:

Storm Hardening Initiatives, Development of a LIPA Policy and Long Range Plan for Storm Hardening, Draft, July 19, 2006, prepared by Navigant Consulting.

After further consultation with the Long Island Power Authority, PSEG LI is withdrawing this request for confidential treatment.

Respectfully submitted,

Robert G. Grassi
Associate General Regulatory Counsel

cc: Hon. Michelle L. Phillips, Administrative Law Judge (w/out attachment)
Hon. David R. Van Ort, Administrative Law Judge (w/out attachment)
Guy Mazza, Assistant Counsel (w/out attachment)

Storm Hardening Initiatives

Development of a LIPA Policy and
Long Range Plan for Storm Hardening

DRAFT – July 19, 2006

LIPA
Long Island Power Authority

NAVIGANT CONSULTING

Overview

The program initiatives set forth in this document are those that are expected to have greatest potential merit for application on LIPA's system based on the information presently available. Some initiatives are already being implemented and others are currently under consideration.

The initiatives outlined in this document are not intended to be definitive. Few of the individual initiatives have been subject of detailed technical review for application in LIPA's system. Individual initiatives may be modified prior to implementation or even dropped altogether if detailed review suggests that that implementation would be impractical, ineffective, technically or financially prohibitive, or for any other reason cannot be implemented with the intended results.

The program initiatives are planned to be implemented over a long period of time. LIPA anticipates that its storm hardening program will likely evolve during this time based on experience gained from implementation of the program initiatives, lessons learned within the utility industry, and changes in materials and technology.

Cost estimates provided in this document are preliminary estimates of the capital and O&M costs associated with full implementation of the initiatives as proposed. Actual costs are likely to vary from those indicated herein. As a practical matter, LIPA does not anticipate full implementation of all initiatives for reasons stated above, and many initiatives may be implemented in varying degrees as conditions warrant (e.g., pole replacement). Further, the cost estimates do not account for possible secondary impacts of the proposed initiatives (costs or savings).

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We are working to develop a storm hardening policy based on the best combination of opportunities that support LIPA's objectives.

- Assess LIPA's current procedures, policies, and practices:
  - Identify data and information sources, and prepare an interview guide to be used to facilitate discussions with LIPA, KSE, and reference to other utility practices.
  - Interview LIPA and KSE subject matter experts to characterize the existing T&D system, O&M practices and restoration practices. This will include discussion of vulnerabilities, system design, equipment and construction standards, geographic location, asset condition, and coordination with customers and public officials, and regulations. We will also obtain system and event information.
- Develop storm hardening initiatives based on strong utility practices and fit with the LIPA business objectives:
  - Characterize industry best practices for system design, O&M and restoration
  - Provide information of other utility practices
  - Compare and contrast LIPA and other utilities to identify opportunities for improvements. Develop report and presentation to LIPA. This will include the development of initiative summaries that describe each solution and describe its characteristics against the attribute scorecard.

For our purposes, a "Severe Storm" is defined as a Category 3 hurricane (sustained winds of 111-130 mph, storm surge of 9-12 ft above normal) making landfall on Long Island.

The initiatives presented here focus on enhancing the durability of LIPA's T&D system to withstand a severe storm.

Can LIPA improve system performance and service quality in response to severe storms?

DURABILITY	RESILIENCE	RESTORATION
Can LIPA "harden" the system to avoid damage and/or outages?	*Can LIPA enhance system flexibility to deliver service in spite of damage?*	*Can LIPA restore service to more customers more quickly?*
• Are there materials or equipment that resist damage better than those currently used? • Are there configurations that resist or avoid damage better than those currently used? • Are there technologies that can protect the system from damage? • Is the condition of the system contributing to storm damage and outages? • Are there existing improvement projects or programs in these areas?	• Are there configurations that can isolate or reduce the scope of outages? • Can the system be reconfigured in response to damage and outages to maintain service? • Are there resources that can be applied to provide electricity to customers while the delivery system is restored? • Are there existing improvement projects or programs in these areas?	• Can the system be improved to facilitate quicker restoration? • Can LIPA effectively apply more resources to restoration? • Can operations be improved to reduce restoration time? • Are there existing improvement projects or programs in these areas?

LIPA can improve system performance and service quality in response to severe storms.

Can LIPA "harden" the system to avoid damage and/or outages?	Yes, substation equipment and control houses can be hardened to prevent damage from flooding and high winds; transmission and distribution circuits can be strengthened and reconfigured to reduce damage from tree contact and high winds.
Can LIPA enhance system flexibility to deliver service in spite of damage?	Yes, LIPA's investment in distribution automation can be leveraged to enhance operations and limit fault-related equipment damage as a result of severe storms.
Can LIPA restore service to more customers more quickly?	Yes, LIPA can benefit from implementation of communications and information workflow systems to increase the speed and efficiency of damage assessment, outage management, and resource logistics.

Durability and resilience initiatives were rated against several attributes from scope of benefit to the challenge to implement.

Attribute	Weight	Scoring Range (5=Better, 1=Worse) 1–2	3	4–5
Scope of customers benefited	5	Benefits limited to small groups of customers on individual circuits or branches	Regional benefits for large numbers of customers	System-wide benefits for most customers in the LIPA service territory
Improvement for severe storms	5	Limited performance improvement; initiative will not withstand the storm conditions of a direct hit	Significant performance improvement; initiative may not be fully effective against a direct hit	Dramatic performance improvement; initiative delivers results under very severe conditions, including a direct hit by the storm
Routine benefit	2	Limited to no Routine benefit	Significant improvement and benefit for routine operations	Dramatic improvement and benefit for routine operations
Time to benefit	3	Initiative produces incremental improvements, requiring 10-20 years until benefits are realized	Initiative can produce significant benefits within the first 5-10 years	Initiative yields dramatic benefits within 5 years
Challenge to implement	2	May require unfamiliar materials and construction techniques; multiple extended outages; implementation timeframe of single instances may take months to years	Familiar but infrequently used materials and construction techniques; extended equipment outages	Commonly used materials and construction techniques; short and infrequent outages required; can be done as part of routine capital or O&M
Public disturbance	4	Prolonged disruption of public rights of way or private property; strong opposition and customer expense for repair/reconfiguration; significant environmental impact	Disruption of public rights of way or private property, possibly involving opposition from customers; environmental impact	Little or no public disturbance; limited to minor inconvenience created by utility construction (e.g., temporary traffic rerouting)

Preliminary ranking of durability and resilience initiatives.

Category	Number	Description	Cost ($Millions)	Time (Years)	Annual Cost ($Millions)	Scope of customers benefited (5)	Improvement for severe storms (5)	Routine benefit (2)	Time to Benefit (3)	Challenge (2)	Public Disruption (4)	Weighted Score
Durability Substations	D3	Harden substation control houses and outdoor control equipment to withstand high winds, rain and flooding	$ 6	10	$ 1	5	5	2	4	4	5	94
Durability Substations	D2	Reconfigure substations to avoid equipment damage from high winds	$ 65	10	$ 7	5	4	2	4	3	5	87
Durability Transmission	D4	Reduce the impact of tree contact on non-ROW (roadside and LIRR) transmission at voltages of 69 kV and below	$ 416	10	$ 42	4	4	4	5	3	3	81
Durability Transmission	D6	Enhance structure inspection programs to reduce structure failure from mechanical overloads	$ 295	20	$ 15	3	2	3	4	5	5	73
Durability Distribution	D7	Reduce the impact of tree contact on distribution in heavily treed areas	$ 1,140	20	$ 57	3	3	5	5	4	2	71
Durability Substations	D1	Reconfigure substations to avoid equipment damage during flooding	$ 80	10	$ 8	3	4	1	3	2	5	70
Durability Distribution	D8	Enhance pole inspection programs to reduce structure failure from mechanical overloads	$ 900	20	$ 45	2	2	4	4	5	5	70
Durability Transmission	D5	Strengthen overhead transmission to withstand high winds	$ 70	20	$ 4	4	4	3	2	2	3	68
Durability Distribution	D9	Protect padmounted equipment and overhead structures against storm surge	$ 5	5	$ 1	1	2	1	4	5	5	59
Resilience	F1	Leverage distribution automation	$ 65	5	$ 13	3	2	5	4	5	5	77

Restoration initiatives were rated similarly, but focused on process improvement and challenge to implement.

Attribute	Weight	Scoring Range (5=Better, 1=Worse)		
		1 / 2	3 / 4	5
Improvement for severe storms	5	Limited performance improvement; initiative will not withstand the storm conditions of a direct hit	Significant performance improvement; initiative may not be fully effective against a direct hit	Dramatic performance improvement; initiative delivers results under very severe conditions, including a direct hit by the storm
Routine benefit	2	Limited to no Routine benefit	Significant improvement and benefit for routine operations	Dramatic improvement and benefit for routine operations
Challenge to implement	3	Many critical systems/processes affected; very complicated implementation (breath and/or depth of change); extensive coordination and implementation	Small number of systems or processes affected; complicated implementation (breath or depth of change), requires significant level of coordination	Changes are limited to a single system, with simple implementation that can be accomplished as part of ongoing or routine operations

Ranking of restoration initiatives.

						5	2	3	
Category	Number	Description	Cost ($Millions)	Time (Years)	Annual Cost ($Millions)	Improvement for severe storms	Routine benefit	Challenge	Weighted Score
Restoration Processes	R10	Improve logistics processes	$ 1	1	$ 1	5	2	5	44
Systems/Equipment	R02	Improve data and voice communication channels	$ 2	2	$ 1	5	1	5	42
Systems/Equipment	R03	Implement a resource control system	$ 3	3	$ 1	5	3	3	40
Restoration Processes	R09	Improve damage assessment processes	$ 1	1	$ 1	4	2	5	39
Systems/Equipment	R04	Implement an electronic damage inventory system	$ 5	3	$ 2	5	2	3	38
Restoration Resources	R12	Ensure all contracts address contractor storm response	$ 2	1	$ 2	3	4	5	38
Restoration Processes	R07	Develop restoration plans for each storm type and category	$ 1	1	$ 1	4	1	5	37
Systems/Equipment	R06	Procure insulator washing equipment/services	$ 1	1	$ 1	3	3	5	36
Systems/Equipment	R01	Outage Management System	$ 15	2	$ 8	3	5	3	34
Restoration Processes	R08	Develop damage prediction model	$ 1	2	$ 1	3	2	5	34
Restoration Resources	R11	Develop HR support to ensure employee commitment to the restoration effort	$ 1	1	$ 1	3	1	5	32
Systems/Equipment	R05	Improve the restoration management system	$ 2	2	$ 1	2	1	3	21

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There are 13 durability initiatives that range in estimated implementation cost of $5 million to over $1 billion.

						5	5	2	3	2	4	
Category	Number	Description	Cost ($Millions)	Time (Years)	Annual Cost ($Millions)	Scope of customers benefited	Improvement for severe storms	Routine benefit	Time to Benefit	Challenge	Public Disruption	Weighted Score
Durability Substations	D1	Reconfigure substations to avoid equipment damage during flooding	$ 80	10	$ 8	3	4	1	3	2	5	70
Durability Substations	D2	Reconfigure substations to avoid equipment damage from high winds	$ 65	10	$ 7	5	4	2	4	3	5	87
Durability Substations	D3	Harden substation control houses and outdoor control equipment to withstand high winds, rain and flooding	$ 6	10	$ 1	5	5	2	4	4	5	94
Durability Transmission	D4	Reduce the impact of tree contact on non-ROW (roadside and LIRR) transmission at voltages of 69 kV and below	$ 416	10	$ 42	4	4	4	5	3	3	81
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Reconfigure substations to avoid equipment damage during flooding.

Vulnerability:
Up to 20 LIPA substations in low-lying coastal areas may experience flooding associated with a severe storm. While it is unlikely that all of these substations will flood during a single storm, many will see flooding depending on the strength and location of the storm surge.

Equipment damage from flooding is most likely to occur from salt water contamination. However, displacement from wave action and equipment floatation may also be possible.

Source: City of Wilson, NC

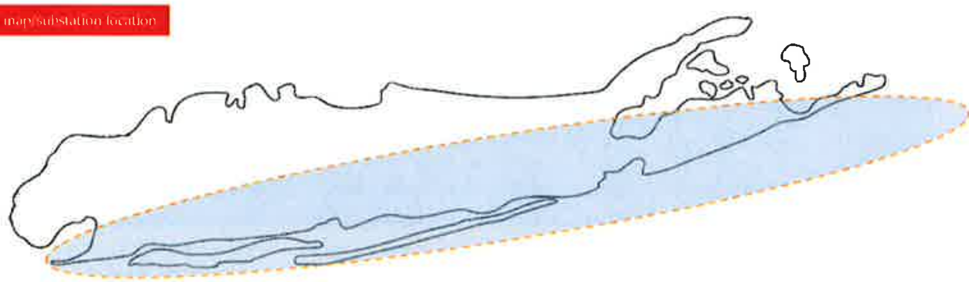
Possible Mitigation Initiatives:

- "Harden" substations
  - Raise equipment foundations (switchgear, tap changers, control panels, batteries)
  - Secure equipment and structures, particularly that which could float when flooded
  - Replace air breakers with vacuum breakers that can withstand contact with salt water
- Rebuild substations with flood-resistant design, with reuse of major equipment as possible
- For small substations in outlying locations that may see the most severe conditions, consider the concept of a modular substation that could be simply and inexpensively replaced
- Develop/modify design standards for substations in low lying areas

Estimated Cost	$80 million		
Scope of customers benefited	3	Time to benefit	3
Improvement for severe storms	4	Challenge to implement	2
Routine benefit	1	Public disturbance	5
		Total weighted score	70

Harden substations subject to storm surge and flooding.

Replace with slosh map/substation location



Mitigation Detail	Estimated Cost	Scope of Customer Benefits	Time to Implementation	Challenge to Implement	Customer Disruption
Harden Barrett Substation	$20 million	Customers in the southwest region	5 years	High	None
Rebuild substations	$50 million (10 @ $5M each)	Customers served from substations	6 months per substation	Moderate	None
Harden substations	$10 million (10 @ $1M each)	Customers served from substations	1 month per substation	Low	None
Total	$80 million				

Reconfigure substations to avoid equipment damage from high winds.

Vulnerability:
All substations in the LIPA service territory are vulnerable to the effects of high winds during a severe storm. Some substations will be more vulnerable due to their configuration and location

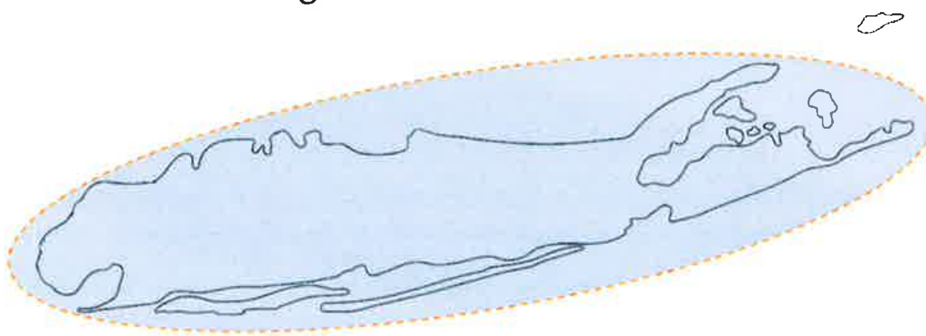
Equipment could sustain damage from the mechanical loads from wind, or by contact from debris blowing into, or from within the substation yard.

Source: Southeast utility

Possible Mitigation Initiatives:
- Modify fences to withstand high winds and protect against flying debris (e.g., higher debris fences, no slats for decreased wind loading, masonry for physical protection)
- Replace 69 kV circuit breaker bushings with 138 kV bushings that can withstand higher winds (130 mph instead of 90 mph). Consider similar replacement for other equipment.
- Secure structures, trailers and other miscellaneous equipment in substation yard
- Modify standards and equipment designs to withstand 130 mph wind
- Adopt a "clean yard" policy (e.g., don't store spare parts, equipment and other material at substations.)
- Replace substandard substation elevated structures in critical substations.
- Priority should be given to those critical transmission substations that support the operation or facilitate restoration of the LIPA system

Estimated Cost	$65 million		
Scope of customers benefited	5	Time to benefit	4
Improvement for severe storms	4	Challenge to implement	3
Routine benefit	2	Public disturbance	5
		Total weighted score	87

Harden substations to high winds.



Mitigation Detail	Estimated Cost	Scope of Customer Benefits	Time to Implementation	Challenge to Implement	Customer Disruption
Modify trans S/S fences for high winds and debris	$50 million (100 @ 500 k)	LIPA service territory	5 years	Low	None
Replace 69kV circuit breaker bushings with 138kV bushings	$15 million (3,000 @ $5k)	LIPA service territory	10 years (10 S/S per year)	Low	None
Total	$65 million				

Harden substation control houses and outdoor control equipment to withstand high winds, rain, and flooding.

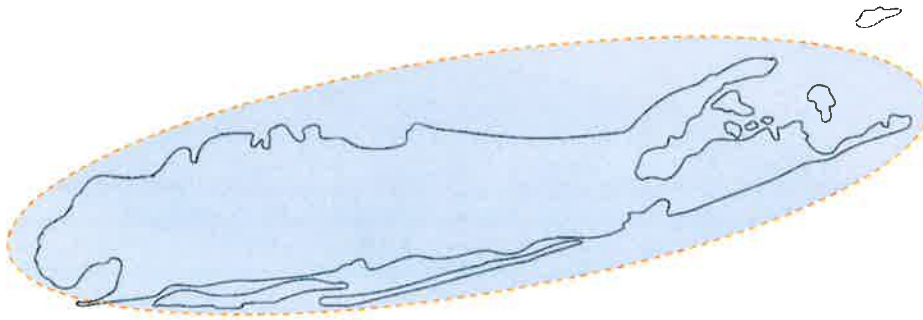
Vulnerability:
All substation control houses in the LIPA service territory are vulnerable to the effects of high winds during a severe storm. Some low lying substations are also vulnerable to flooding.

Due to the critical nature of control houses for protection and control of the LIPA system, it is extremely important to protect them. A structural failure could result in intrusion of debris and rain, leading to damage to relay and control panels, batteries and other vital equipment.

Possible Mitigation Initiatives:
- Strengthen roofs to withstand wind
- Install hurricane shutters on windows
- Install tie-down straps on control houses
- Prevent intrusion of wind-driven rain
- Prevent flood water from coming in under doors or through vents
- Review external battery sheds for vulnerabilities and install rain intrusion restriction on vents
- Seal control cable conduit
- Standardize on NEMA 4 enclosures for outdoor control equipment and replace existing enclosures
- Adopt hurricane resistant design for control houses
- Priority should be given to those substations most critical to the operation of the LIPA transmission system (e.g., 50 transmission/distribution stations).

Estimated Cost	$6 million		
Scope of customers benefited	5	Time to benefit	4
Improvement for severe storms	5	Challenge to implement	4
Routine benefit	2	Public disturbance	5
		Total weighted score	94

Harden control houses and outdoor control equipment.



Mitigation Detail	Estimated Cost	Scope of Customer Benefits	Time to Implementation	Challenge to Implement	Customer Disruption
Rebuild or protect (wall) control buildings to withstand wind	$2.2 million (110 @ $20k)*	LIPA service territory	10 years	Medium	None
Tie-down straps on buildings and roofs	$0.55 million (110 @ $5K)*	LIPA service territory	10 years	Low	None
Seal control houses and external structures from rain	$0.2 million (220 @ $1K)*	LIPA service territory	10 years	Low	None
NEMA 4 enclosures for all outdoor control boxes	$ 3 million (875 @ $3k)	LIPA service territory	10 years	Low	None
Total	$ 6 million	*Assumes 175 subs and ¼ of them have battery buildings for a total of 220 buildings. Assume 5 control boxes per substation			

Reduce the impact of tree contact on non-ROW (roadside and LIRR) transmission at voltages of 69 kV and below.

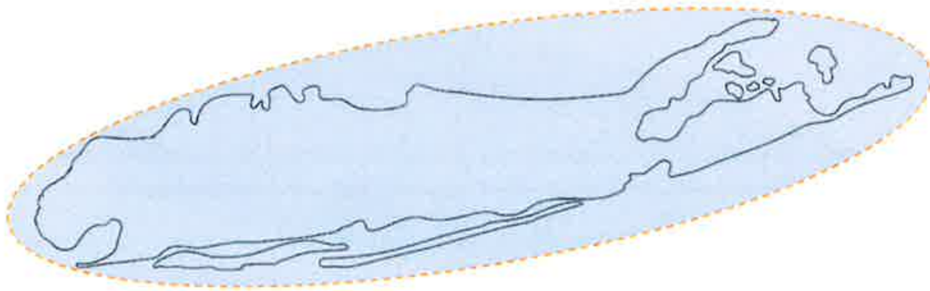
Vulnerability:
In parts of the LIPA system, transmission at 69 kV and below is built along roads through heavily treed areas with narrow clearances. Areas along the North Shore may be particularly challenging where customers resist adequate tree trimming, and trees have grown very large and overhang lines.

High winds may cause trees and limbs to break and fall into conductors and structures. This situation is exacerbated when rain-saturated soil can cause trees to topple into lines.

Possible Mitigation Initiatives:
- Expand clearance beyond 18 feet on non-ROW lines, including removal of large trees at the edge of the clearance zone that may topple
- Expand "wire friendly tree" program
- Apply aerial cable construction to roadside transmission lines at 33 kV and below in heavily treed areas
- Apply selective undergrounding to roadside transmission in heavily treed areas where line clearance or compact/spacer construction is impractical
- These initiatives may have the greatest opportunity to improve reliability in the North Shore region with its large trees significant encroachment. While undergrounding may be the most physically robust solution, it may also be the most expensive. Tree trimming can be less expensive, but may receive overwhelming opposition in some areas. Selection of specific approaches should based on life cycle cost and practicality of implementation.

Estimated Cost	$416 million		
Scope of customers benefited	4	Time to benefit	5
Improvement for severe storms	4	Challenge to implement	3
Routine benefit	4	Public disturbance	3
		Total weighted score	81

Reduce tree contact on non-ROW transmission at 69 kV and below.



Mitigation Detail	Estimated Cost	Scope of Customer Benefits	Time to Implementation	Challenge to Implement	Customer Disruption
Expand standard 69 kV trim clearances beyond 18 feet and wire friendly tree program	$ 230M (115 mi @ $ 100k/yr)	LIPA service territory	3 years	Low	Moderate
69 kV selective undergrounding	$100M million (30 miles @ $3.3M/mile)	Customers in region served	1-5 years	Moderate	Moderate
<33 kV aerial cable or tree wire in heavily treed areas	$48M million (80 @ $ 600k)	Customers in region served	5-10 years	Moderate	Moderate
33 kV selective undergrounding	$38M (12.5 miles @ $3.3M/mile)	Customers in region served	1-5 years	Moderate	Moderate
Total	$416M	Assumptions: • Half of <33kV will be spacer cable (60 miles) • 10% of all non-ROW transmission will be undergrounded (30 miles) • Half of all miles of roadside 69 kV is heavily treed (80 miles)			

Strengthen overhead transmission to withstand high winds.

Vulnerability:
Much of the LIPA 69 kV and 33 kV transmission system is built on wood poles that may not withstand the mechanical loads of wind and tree impact during a severe storm. Due to their physical size and associated mechanical loads, transmission structures are challenging to erect particularly in remote or hard to access areas, including rear property or cross country locations.

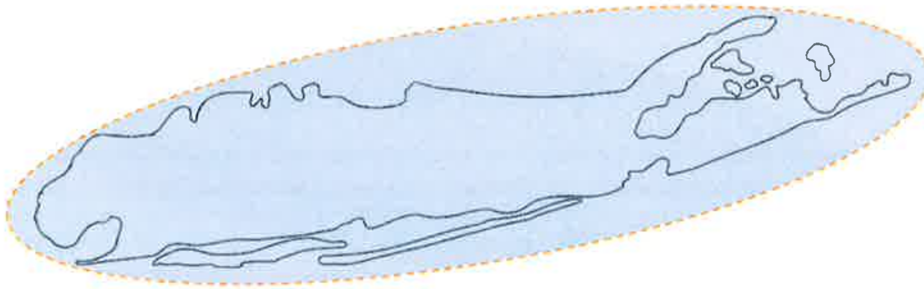
Current NY DOT regulations prohibit high strength poles along road as they will not break away when struck by with motor vehicles.

Possible Mitigation Initiatives:

- Replace 69 kV and 33 kV wood structures with high strength poles in heavily treed areas and on rear property
- Upgrade crossarms to withstand higher loads, and replace porcelain insulators with polymer
- Standardize on high strength poles in more applications, including the reinforcement of major roadway crossings, including dead-ends, to prevent downed wires in roadways
- Adopt the NESC Extreme Wind criteria for transmission
- High strength poles (e.g., concrete and steel) are increasingly used by utilities in the southeast who are prone to hurricanes. LIPA currently uses steel poles on its 138 kV transmission system, and also along railroad lines. By expanding the use of high strength poles, LIPA can decrease the chance of poles breaking under wind load, and when lines are struck by trees and debris.
- A barrier to implementing this initiative is the DOT regulation against high strength poles along roads. LIPA could seek to modify this regulation in the interest of energy reliability and security for Long Island.

Estimated Cost	$70 million		
Scope of customers benefited	4	Time to benefit	2
Improvement for severe storms	4	Challenge to implement	2
Routine benefit	3	Public disturbance	3
		Total weighted score	68

Strengthen overhead transmission to withstand high winds.



Mitigation Detail	Estimated Cost	Scope of Customer Benefits	Time to Implementation	Challenge to Implement	Customer Disruption
Replace 69kV and 33kV wood structures with HS steel poles in heavily treed areas non-ROW	$43 million $10k per pole	Customers in region served	20 years	Low	None
Replace 69kV and 33kV wood structures with HS steel poles on rear property	$18 million $20k per pole	Customers in region served	20 years	Moderate	Moderate
Standardize on high strength poles for applications subject to high mechanical loads (heavy joint use)		LIPA service territory	Immediate	Low	Low
Upgrade crossarms and replace porcelain insulators with polymer	$9 million $10k per pole	LIPA service territory	20 years	Low	None
Adopt NESC Extreme Wind criteria for transmission		LIPA service territory	Immediate	Low	None
Total	$70 million	Assumptions: • 17,000 transmission / T&D poles • 378 miles of ROW transmission at 69kV and below; 10% rear property • 355 miles of non-ROW transmission at 69kV and below • Half of non-ROW transmission at 69kV and below is heavily treed.			

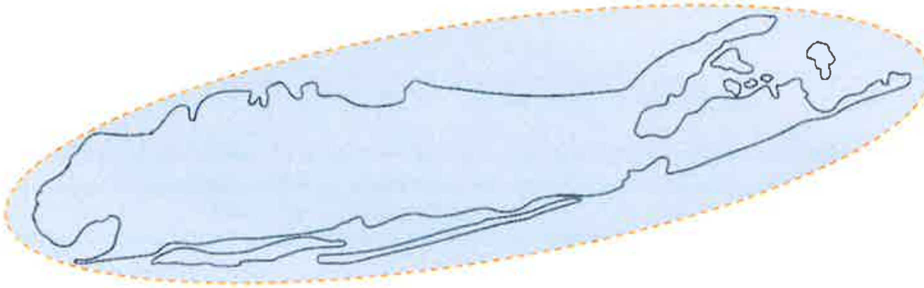
Ensure structure inspection program is consistent with good utility practice to reduce structure failure from mechanical overloads.

Vulnerability:
Adherence to design specifications is critical to ensuring that transmission structures can withstand mechanical loading during a severe storm. Structures in a weakened or overloaded condition are more likely to fail during storm conditions.

Possible Mitigation Initiatives:
- Adopt common utility practice in the structure inspection program to cover both physical condition and joint use attachments (with focus on joint use attachments on 69 kV). This should include attachment policies and design standards, as well as the physical inspection approach.
- Arrest cascading failures
- Replace poles that are found to be in insufficient condition as a result of inspection
- Replace poles that are substandard (i.e., insufficient size/class) regardless of condition

Estimated Cost	$295 million		
Scope of customers benefited	3	Time to benefit	4
Improvement for severe storms	2	Challenge to implement	5
Routine benefit	3	Public disturbance	5
		Total weighted score	73

Ensure structure inspection program is sufficient to reduce structure failure from mechanical overloads.



Mitigation Detail	Estimated Cost	Scope of Customer Benefits	Time to Implementation	Challenge to Implement	Customer Disruption
Replace structures that fail inspection	$85 million (2.5% of poles/yr)	LIPA service territory	20 years	Low	None
Replace substandard structures based on size/class	$210 million	LIPA service territory	20 years	Low	None
Total	$295 million	Assumptions: • 17,000 transmission or T&D poles in total • Poles failing inspection are currently replaced as part of current inspection program • Approximately 16,000 poles fall below present standards • $10k to replace each pole • Pole replacement over 20 years			

Reduce the impact of tree contact on distribution in heavily treed areas.

Vulnerability:
Vegetation management is a proven approach to reducing outages and system damage during severe storms. LIPA can enforce and expand its existing program to improve performance.

Vegetation management can complement other durability solutions to reduce the impact of tree contact.

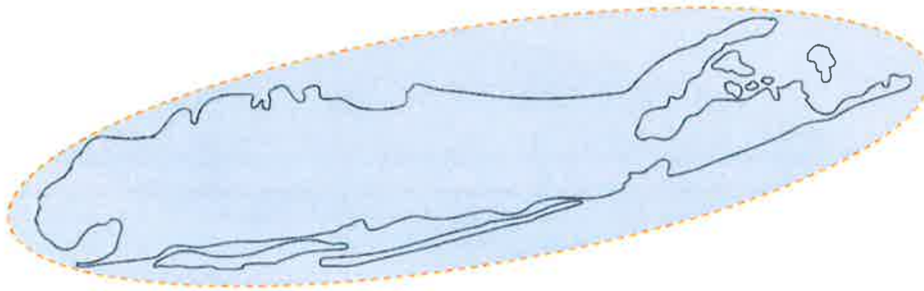
This vulnerability may be highest in the North Shore region with its large trees and significant right of way encroachment.

Possible Mitigation Initiatives:

- Expand clearance beyond 18 feet on distribution, including removal of large trees at the edge of the clearance zone that may topple. In cases where landowners deny permission for tree hazardous tree removal and damage is caused, costs will be assessed to the landowner; need to flag this for land ownership changes
- Expand "wire friendly tree" program
- Apply spacer cable construction to distribution in heavily treed areas
- Apply selective undergrounding to distribution in heavily treed areas where line clearance or compact/spacer construction is impractical. Underground standards should be modified to cope with or protect against flooding in coastal areas.
- While undergrounding may be the most physically robust solution, it may also be the most expensive. Tree trimming can be less expensive, but may receive overwhelming opposition in some areas. Selection of specific approaches should based on life cycle cost and practicality of implementation.

Estimated Cost	$1,140 million		
Scope of customers benefited	3	Time to benefit	5
Improvement for severe storms	3	Challenge to implement	4
Routine benefit	5	Public disturbance	2
		Total weighted score	71

Reduce the impact of tree contact on distribution in heavily treed areas.



Mitigation Detail	Estimated Cost	Scope of Customer Benefits	Time to Implementation	Challenge to Implement	Customer Disruption
Expand standard trim clearances and wire friendly tree program	$90 million (300 miles @ $15k/yr)	Customers in heavily treed areas	20 years	Low	Moderate
Apply spacer cable construction	$60 million (miles @ $ 200k)	Customers in heavily treed areas	20 years	Moderate	Moderate
Apply selective undergrounding	$990 million (300miles @ 3.3M/mile)	Customers in heavily treed areas	20 years	Moderate	Moderate
Total	**$1,140 million**				

Assumptions:
- One third of OH distribution main lines are in heavily treed areas (2676 x 0.33 = 892 miles)
- Each mitigation initiative will be applied to one third of the OH distribution in heavily treed areas (~300 miles each)

Ensure pole inspection programs are consistent with good utility practice to reduce structure failure from mechanical overloads.

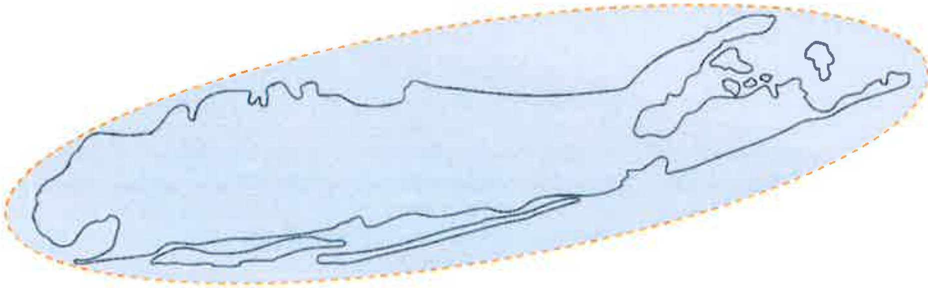
Vulnerability:
Adherence to design specifications is critical to ensuring that distribution poles can withstand mechanical loading during a severe storm. Poles in a weakened or overloaded condition are more likely to fail during storm conditions.

Possible Mitigation Initiatives:
- Enhance the pole inspection program to cover both physical condition and joint use attachments. This should include attachment policies and design standards, as well as the physical inspection approach.
- Replace poles that are found to be in insufficient condition as a result of inspection
- Replace poles that are substandard (i.e., insufficient size/class) regardless of condition
- Priority should be given to those poles that support distribution automation system equipment, including ASUs, manual switches and other equipment

Source: US Department of Energy

Estimated Cost	$900 million		
Scope of customers benefited	2	Time to benefit	4
Improvement for severe storms	2	Challenge to implement	5
Routine benefit	4	Public disturbance	5
		Total weighted score	70

Ensure pole inspection program is adequate to reduce failure from mechanical overloads.

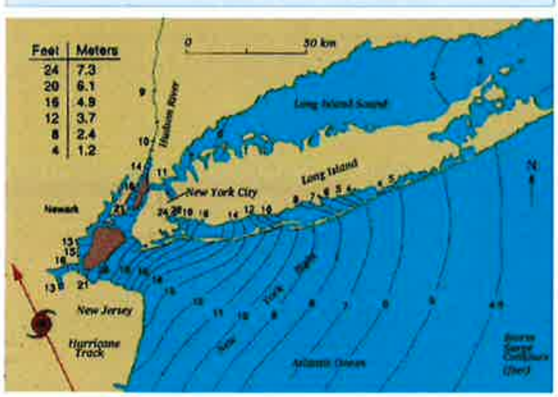


Mitigation Detail	Estimated Cost	Scope of Customer Benefits	Time to Implementation	Challenge to Implement	Customer Disruption
Replace poles found to be in insufficient condition	$5 million per year	LIPA service territory	Ongoing	Low	None
Replace substandard poles regardless of condition	$40M/yr 5,000 poles/yr for a total of 100,000 poles	LIPA service territory	20 years	Low	None
Total	$900 million	Assumptions: • The current distribution inspection program invests $5 million in pole replacement each year • $6M for accidents, with reimbursement for $2M			

Protect distribution equipment and structures from being displaced/damaged by a storm surge in low-lying areas.

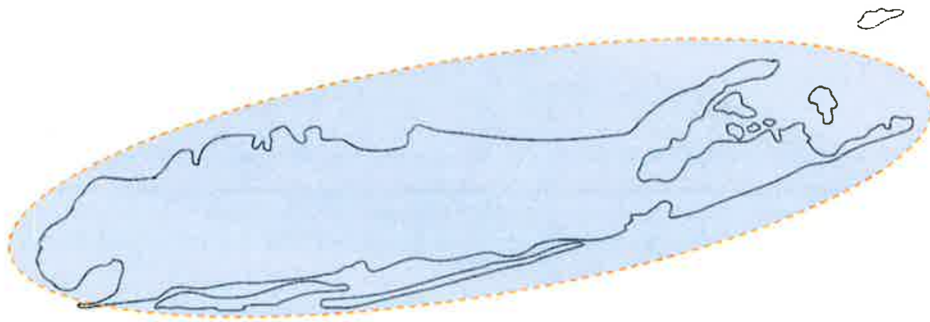
Vulnerability:
In low-lying areas, a storm surge, with its associated flooding and wave action, can cause damage to underground utilities.

Mitigation Initiatives:
- Secure pad-mounted equipment to robust foundations.
- Flag equipment so it can be identified among storm surge debris, e.g., transformers, switches
- Review and modify, as appropriate, the design standards for UG construction in areas potentially affected by storm surge
- Consider use of submersible equipment in selected situations
- Review and modify, as appropriate, the design standards for overhead construction in areas potentially affected by storm surge



Estimated Cost	$5 million		
Scope of customers benefited	1	Time to benefit	4
Improvement for severe storms	2	Challenge to implement	5
Routine benefit	1	Public disturbance	5
		Total weighted score	59

Harden distribution equipment and structures against storm surge over 20 years.



Mitigation Detail	Estimated Cost	Scope of Customer Benefits	Time to Implementation	Challenge to Implement	Customer Disruption
Secure pad-mounted equipment	$5 million	LIPA service territory	5 years	Low	None
Modify UG design standards		LIPA service territory	Ongoing	Low	None
Modify OH design standards		LIPA service territory	Ongoing	Low	None
Total	$5 million				

LIPA can increase the durability of its system by hardening against flooding, high winds and tree contact.

Are there materials or equipment that resist damage better than those currently in use?	Yes, equipment and materials that resist salt water and physical impact will reduce the change of damage leading to failure and outages. Flood resistant substation designs, and use of equipment that resists tree contact and high winds on T&D circuits will improve durability.
Are there configurations that resist or avoid damage better than those currently used?	Yes, substations can be hardened against flooding and high winds by raising equipment, strengthening control houses, and preventing flying debris from striking critical substation equipment. Aggressive vegetation management and undergrounding reduce damage on T&D circuits.
Are there technologies that can protect the system from damage?	Technologies for protecting equipment are being developed. Recent interest in energy infrastructure security is leading to the development of technologies that can help equipment withstand severe impacts from blasts and projectiles. Such technologies may be employed to prevent damage from a severe storm.
Is the condition of the system contributing to storm damage and outages?	Not clear. Since LIPA has not experienced a severe storm in several years, the system has not suffered severe damage. Portions of the system have been replaced and upgraded as part of capital improvement, and are capable of withstanding storm conditions. To the extent that there is equipment in weakened or substandard condition, this could contribute to failures.
Are there existing improvement projects or programs in these areas?	Yes, LIPA is implementing ongoing programs for wood pole inspection, replacement, and reinforcement, vegetation management, distribution automation, and undergrounding. Capital improvements are made on the lowest performing circuits, including cable replacement, and refurbishment of secondary networks.

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LIPA's distribution automation could be further leveraged to improve system resilience.

Category	Number	Description	Cost ($Millions)	Time (Years)	Annual Cost ($Millions)	Scope of customers benefited	Improvement for severe storms	Routine benefit	Time to Benefit	Challenge	Public Disruption	Weighted Score
						5	5	2	3	2	4	
Resilience	F1	Leverage distribution automation	$ 25	5	$ 5	3	2	5	4	5	5	77
Resilience	F1	Distributed generation and microgrids	$ 40	10	$ 4	3	4	2	4	5	4	77

Leverage LIPA's leading distribution automation system to manage the scope of outages, and speed reconfiguration and restoration.

Vulnerability:
LIPA has a significant investment in distribution automation, and is one of the leading utilities in the US in the application of this relatively new technology.

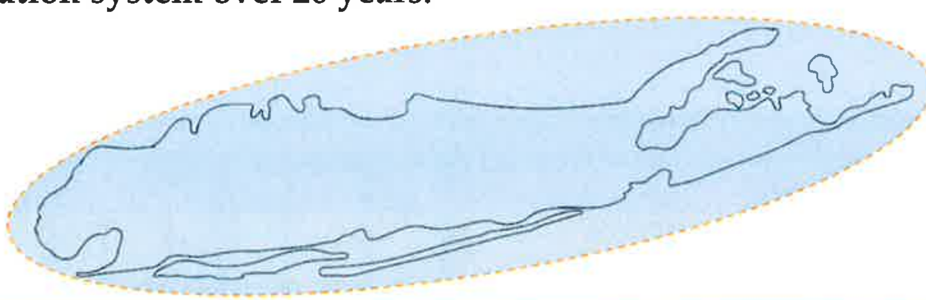
Possible Mitigation Initiatives:

- Consider the deployment of circuit reclosers for which the reclose/lockout settings can be changed remotely/automatically
- Ensure that distribution automation is a centerpiece of LIPA distribution planning, design and standards, expand automation to primary branch circuits
  - Ensure that distribution automation devices and equipment are protected as highest priority items on the distribution system
  - Take advantage of distribution circuit upgrades to ensure that circuits can be fed from multiple locations in the event of outages
- Investigate the value of de-energizing circuits before faults from high winds and flooding
- Consider the incorporation of distributed generation and microgrids in distribution planning and design over time

Source: S&C Electric

Estimated Cost	$65 million		
Scope of customers benefited	3	Time to benefit	4
Improvement for severe storms	2	Challenge to implement	5
Routine benefit	5	Public disturbance	5
		Total weighted score	77

Enhance the capability of the already extensive distribution automation system over 20 years.



Mitigation Detail	Estimated Cost	Scope of Customer Benefits	Time to Implementation	Challenge to Implement	Customer Disruption
Consider automated circuit reclosers to enable remote settings changes		LIPA service territory	ongoing	Low	None
Expand automation to high value primary branch circuits	$25 million (500 ASUs x $50,000)	LIPA service territory	20 years	Low	None
Consider the incorporation of distributed generation and microgrids in distribution planning and design including mobile gen	$40 million	LIPA service territory	10 years	Low	None
Investigate the value of de-energizing circuits before faults from high winds and flooding		LIPA service territory	Ongoing	Low	None
Total	$65 million	LIPA service territory	5 years	Low	None

Assumptions:
- 1000 ASUs in service, 500 additional ASUs to cover high value primary branch circuits
- Possible procurement of 20 mobile gen units (1 MW)

LIPA can increase the resilience of its system by leveraging its industry leading implementation of distribution automation.

Are there configurations that isolate or reduce the scope of outages?	Yes, looped or networked T&D configurations support serving load in the event that normal sources are interrupted due to faults and damage. LIPA's system is already looped, and most loads can be fed from alternate sources.
Can system be reconfigured in response to damage and outages to maintain service?	Yes, most transmission systems have monitoring and control capabilities for remote/automatic reconfiguration in real time. Distribution automation offers similar capabilities for distribution systems, and is increasingly being applied by utilities to improve reliability (CAIDI) and service quality (voltage, power quality).
Are there resources that can be applied to provide electricity to customers while delivery system is restored?	While resources such as backup generation exist, they are not generally applied by LIPA for resilience purposes. The use of distributed generation or microgrids could be investigated to determine its value to enhance the resiliency of the LIPA system.
Are there existing improvement projects or programs in these areas?	LIPA has invested significantly in distribution automation to support remote/automatic system reconfiguration in response to outages. However, automatic reconfiguration is not generally practiced. The distribution automation system could be leveraged to increase the speed of reconfiguration.

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Many of the restoration initiatives focus on improvement of logistics.

Category	Number	Description	Cost ($Millions)	Time (Years)	Annual Cost ($Millions)	Improvement for severe storms (5)	Routine benefit (2)	Challenge (3)	Weighted Score
Systems/Equipment	R01	Outage Management System	$ 15	2	$ 8	3	5	3	34
Systems/Equipment	R02	Improve data and voice communication channels	$ 2	2	$ 1	5	1	5	42
Systems/Equipment	R03	Implement a resource control system	$ 3	3	$ 1	5	3	3	40
Systems/Equipment	R04	Implement an electronic damage inventory system	$ 5	3	$ 2	5	2	3	38
Systems/Equipment	R05	Improve the restoration management system	$ 2	2	$ 1	2	1	3	21
Systems/Equipment	R06	Procure insulator washing equipment/services	$ 1	1	$ 1	3	3	5	36
Restoration Processes	R07	Develop restoration plans for each storm type and category	$ 1	1	$ 1	4	1	5	37
Restoration Processes	R08	Develop damage prediction model	$ 1	2	$ 1	3	2	5	34
Restoration Processes	R09	Improve damage assessment processes	$ 1	1	$ 1	4	2	5	39
Restoration Processes	R10	Improve logistics processes	$ 1	1	$ 1	5	2	5	44
Restoration Resources	R11	Develop HR support to ensure employee commitment to the restoration effort	$ 1	1	$ 1	3	1	5	32
Restoration Resources	R12	Ensure all contracts address contractor storm response	$ 2	1	$ 2	3	4	5	38

Upgrade the Outage Management System

Vulnerability:
Inefficient damage assessment and storm management tool.

CARES system is not linked to GIS, does not have customer association or switching order management. The CARES is not used during major storm restorations.

Possible Mitigation Initiatives:
- Upgrade to an OMS that includes GIS link, customer association, switching orders, and other storm management features.

Estimated Cost	$15-20 million over two years		
Improvement for severe storms	3	Challenge to implement	3
Routine benefit	5	Total weighted score	34

Mitigation Detail	Estimated Cost	Scope of Customer Benefits	Time to Implementation	Challenge to Implement	Customer Disruption
Upgrade OMS	$ 15-20 million	LIPA service territory	2 years	Moderate	None

Improve Voice and Data Communication Channels

Vulnerability:
Inefficient communication channels for voice and data become bottlenecks in large scale restorations and slow the restoration process.

Voice and data communication are critical in a restoration process. Improving the availability, capacity, and reliability of communications among LIPA, contractors, and foreign crews increases the efficiency and effectiveness of the restoration processes.

Mitigation Initiatives:
- Improve data communication channels for substations. This initiative is currently under investigation by KSE.
- Invest in mobile communication towers.
- Provide common voice/data communication among LIPA, contractor, foreign crews, and other utility and emergency response organizations.
- Pre-deploy communication facilities to staging and receiving sites, or pre-staging area where it is not vulnerable to storm damage.

Estimated Cost	$2.1 million		
Improvement for severe storms	5	Challenge to implement	5
Routine benefit	1	Total weighted score	42

Mitigation Detail	Estimated Cost	Scope of Customer Benefits	Time to Implementation	Challenge to Implement	Customer Disruption
Improve data communication to restoration substations (92)	$ 0.2 million	LIPA service territory	2 years	Low	None
Invest in mobile communication towers	$ 0.1 million	LIPA service territory	1 year	Low	None
Provide common voice/data communication	$ 1 million	LIPA service territory	3 years	Moderate	None
Pre-deploy communication facilities to staging sites	$ 0.1 million	LIPA service territory	1 years	Low	None
Implement mobile command center	$ 0.7 million	LIPA service territory	1 years	Low	None
Total	$ 2.1 million				

Implement a resource control system to track all restoration personnel, crew vehicles, and critical equipment

Vulnerability:
Inefficient use of resources (e.g., crew, special equipment) due to inability to locate them in a timely manner. Inability to communicate geographic location to emergency responders.

An inadequate control of resources may result in inefficient allocation and use of those resources during the restoration. Ultimately, inadequate resource controls result in slower restorations.

GPS information provides foreign crews location awareness thus reducing the chances of getting lost.

Mitigation Initiatives:
- Deploy an automatic vehicle location system (GPS) for all restoration crew vehicles.
- Leverage GIS to develop GPS coordinates to communicate damage location to crews.
- Implement a resources control system to track all restoration personnel (including foreign and contractor crews), and critical equipment:
  - Implement a computer readable ID card system and deploy to all restoration sites.
  - Implement a bar code/RFID inventory control to track equipment issued to crews for each work order.
  - (Current system to track meters is a good example of how this could be implemented)

Estimated Cost	$3.2 million		
Improvement for severe storms	5	Challenge to implement	3
Routine benefit	3	Total weighted score	40

Mitigation Detail	Estimated Cost	Scope of Customer Benefits	Time to Implementation	Challenge to Implement	Customer Disruption
Deploy GPS to all restoration crew vehicles	$ 1.3 million	LIPA service territory	3 years	Moderate	None
Leverage GIS to develop GPS coordinates to communicate damage location for crews	$ 0.2 million	LIPA service territory	1 year	Low	None
Implement a resources control system	$ 1 million	LIPA service territory	1 year	Low	None
Implement a computer readable ID card system and deploy to all restoration sites	$ 0.5 million	LIPA service territory	1 year	Low	None
Implement a bar code/RFID inventory control to track equipment issued to crews	$ 0.2 million	LIPA service territory	2 years	Low	None
Total	$ 3.2 million				

Implement an electronic damage inventory system

Vulnerability:
Slow damage inventory that forces management to make suboptimal procurement and allocation decisions.

Damage inventory is critical to the restoration process. Efficient procurement and allocation of resources and material depends on quick and accurate damage inventory.

Mitigation Initiatives:
- Implement an electronic damage inventory system. An R&D project is currently underway at LIPA/KSE.
- Consider best way to communicate data reliably to make it available as quickly as possible. Note that cell phone service may be unavailable in the wake of a severe storm.

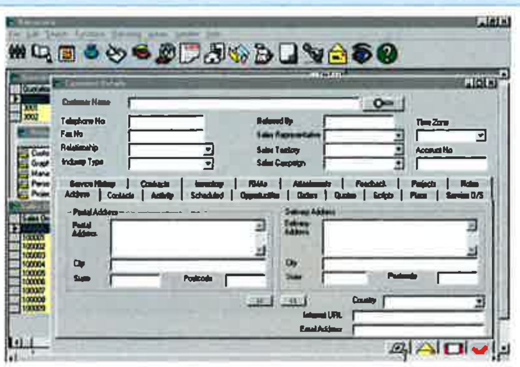
Estimated Cost	$5 million		
Improvement for severe storms	5	Challenge to implement	3
Routine benefit	2	Total weighted score	38

Mitigation Detail	Estimated Cost	Scope of Customer Benefits	Time to Implementation	Challenge to Implement	Customer Disruption
Implement an electronic damage inventory system	$5 million	LIPA service territory	3 years	Moderate	None

Improve the restoration management system

Vulnerability:
Inefficient restoration management system can reduce productive time.

Quick and efficient access to information is essential to decision making, and to the prosecution of the restoration plan.



Mitigation Initiatives:
- Automate reports (e.g., switching status).
- Improve the restoration system user interface.
- Integrate databases to facilitate the access to information.
- Implement an electronic completion system for work tickets. This initiative is currently underway at LIPA/KSE.
- Use IVR to confirm that customer power has been restored. This initiative is currently underway at LIPA/KSE.
- Automate the tracking of system element performance in storm conditions.

Estimated Cost	$2.1 million		
Improvement for severe storms	2	Challenge to implement	3
Routine benefit	1	Total weighted score	21

Mitigation Detail	Estimated Cost	Scope of Customer Benefits	Time to Implementation	Challenge to Implement	Customer Disruption
Automate reports (e.g., switching status)	$ 0.5 million	LIPA service territory	2 years	Moderate	None
Improve the restoration system user interface	$ 0.3 million	LIPA service territory	2 years	Low	None
Integrate databases to facilitate the access to information	$ 1 million	LIPA service territory	2 years	Moderate	None
Implement an electronic completion system for work tickets	$ 0.2 million	LIPA service territory	1 year	Low	None
Use IVR to confirm that customer power has been restored	$ 0 million	LIPA service territory	1 year	Low	None
Automate the tracking of system element performance	$ 0.1 million	LIPA service territory	2 years	Low	None
Total	$ 2.1 million				

Procure insulator washing equipment/services

Vulnerability:
Salt accumulation on transmission and substation insulators and equipment that can result in flashovers and outages even days after the storm.

Storm winds can carry salt spray that accumulates on transmission and substation equipment many miles inland. Storm surges can also contaminate substation and distribution equipment.

Mitigation Initiatives:
- Invest in insulator washing equipment that could be used to wash substation equipment contaminated by salt water, as well as transmission and substation insulators.

Estimated Cost	$0.5 million		
Improvement for severe storms	3	Challenge to implement	5
Routine benefit	3	Total weighted score	36

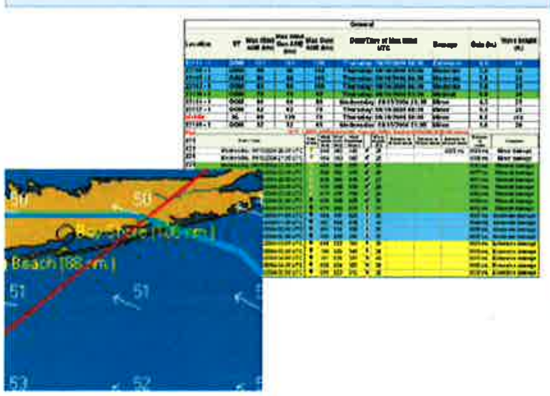
Mitigation Detail	Estimated Cost	Scope of Customer Benefits	Time to Implementation	Challenge to Implement	Customer Disruption
Procure insulator washing equipment	$ 0.5 million	LIPA service territory	1 year	Low	None
Contract for insulator and equipment washing services	$ 0 million	LIPA service territory	1 year	Low	None
Total	$ 0.5 million				

Develop restoration plans addressing various storm conditions

Vulnerability:
Generic defined restoration plans.

Efficient restoration depends on a well defined plan tailored to the situation.

Possible Mitigation Initiatives:
- Develop plans tailored to optimize the effectiveness and efficiency of the restoration process under varying storm conditions. (KSE is revising its restoration plan to include variations in conditions.)
- Re-evaluate material inventory levels required under differing conditions (e.g., anticipated damage).



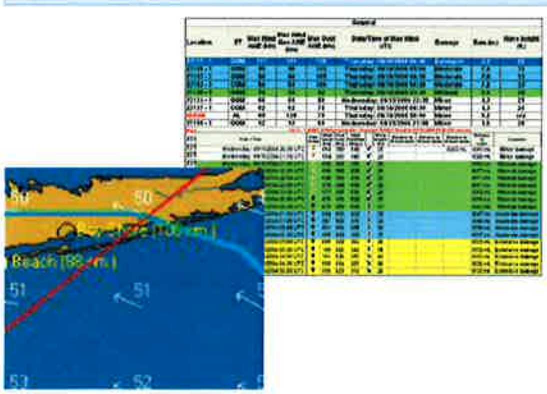
Estimated Cost	$1 million		
Improvement for severe storms	4	Challenge to implement	5
Routine benefit	1	Total weighted score	37

Mitigation Detail	Estimated Cost	Scope of Customer Benefits	Time to Implementation	Challenge to Implement	Customer Disruption
Develop plans for each type and category of storm	$ 1 million	LIPA service territory	1 year	Low	None

Develop damage prediction model

Vulnerability:
Inability to predict type, location, and extent of damage.

An inadequate prediction of damage may result in inadequate resource decisions or improper allocation of critical resources. Ultimately, inadequate resource allocation result in slower restorations.



Possible Mitigation Initiatives:
- Develop a storm damage prediction model to assist management decisions relative to resource and material needs.
- Leverage GIS data to develop damage estimates. (This is an existing capability for KSE.)
- Monitor and evaluate processes, systems, and experiences of other utilities.

Estimated Cost	$0.5 million		
Improvement for severe storms	3	Challenge to implement	5
Routine benefit	2	Total weighted score	34

Mitigation Detail	Estimated Cost	Scope of Customer Benefits	Time to Implementation	Challenge to Implement	Customer Disruption
Develop a storm damage prediction model to assist management decisions	$ 0.3 million	LIPA service territory	2 years	Low	None
Leverage GIS data to develop damage estimates	$ 0.2 million	LIPA service territory	1 year	Low	None
Total	$ 0.5 million				

Improve damage assessment processes

Vulnerability:
Slow initial damage assessment process.

An inadequate initial damage assessment may result in inadequate resource decisions or improper allocation of critical resources. Ultimately, inadequate resource decisions result in slower restorations.

Possible Mitigation Initiatives:
- Contract for post-storm aerial patrols for transmission lines and remote distribution facilities.
- Develop specific plans and criteria for aerial patrols.
- Implement a quick initial damage assessment plan using pre-planned survey routes for personnel commuting to assigned locations. This initiative is currently under investigation by KSE.

Estimated Cost	$0.3 million		
Improvement for severe storms	4	Challenge to implement	5
Routine benefit	2	Total weighted score	39

Mitigation Detail	Estimated Cost	Scope of Customer Benefits	Time to Implementation	Challenge to Implement	Customer Disruption
Contract for post-storm aerial patrols	$ 0 million	LIPA service territory	1 year	Low	None
Develop specific plans and criteria for aerial patrols	$ 0.1 million	LIPA service territory	1 year	Low	None
Implement a quick initial damage assessment plan using pre-planned survey routes	$ 0.2 million	LIPA service territory	1 year	Low	None
Total	$ 0.3 million				

Improve logistics processes

Vulnerability:
Inefficient logistics that slow down the restoration process.

Inefficient logistics reduces restoration personnel productive time and slows down the restoration process.

Possible Mitigation Initiatives:

- Structure the logistics processes to minimize field crews unproductive time (e.g., provisioning the trucks in the evenings, delivering major equipment to job sites, procuring crew lodging near staging site).
- Deploy auditors to monitor crews and materials during restoration.
- Incorporate receiving (off island foreign crew processing center) and staging site into the logistics process. (This initiative is currently under investigation by KSE.)
- Note: KSE has retained the services of a logistics contractor to assist in developing improved restoration logistics program.

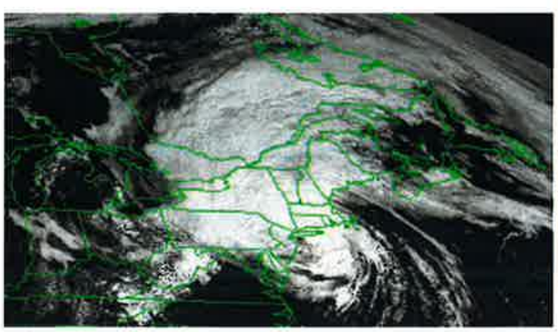
Estimated Cost	$1 million		
Improvement for severe storms	5	Challenge to implement	5
Routine benefit	2	Total weighted score	44

Mitigation Detail	Estimated Cost	Scope of Customer Benefits	Time to Implementation	Challenge to Implement	Customer Disruption
Structure the logistics team to minimize field crews unproductive time	$ 0.2 million	LIPA service territory	1 year	Low	None
Deploy auditors to monitor crews and materials during restoration	$ 0.3 million	LIPA service territory	1 year	Low	None
Incorporate receiving and staging site into the logistics process	$ 0.5 million	LIPA service territory	1 year	Low	None
Total	$ 1.0 million				

Develop HR support to ensure employee commitment to the restoration effort

Vulnerability:
Low turn-out of employees and contractors following the storm

A strong turn-out of restoration personnel is critical during the initial stages of the restoration process. Addressing employees' housing and family emergencies prior to the storm improves turn-out immediately following the storm and enhances their commitment to the restoration effort.



Possible Mitigation Initiatives:
- Provide shelter for displaced employees and their families.
- Arrange temporary daycare for employee children and elderly dependents.
- Stockpile materials that employees could use for temporary repairs to their homes.
- Note: KeySpan is currently considering these types of initiatives.

Estimated Cost	$0.9 million		
Improvement for severe storms	3	Challenge to implement	5
Routine benefit	1	Total weighted score	32

Mitigation Detail	Estimated Cost	Scope of Customer Benefits	Time to Implementation	Challenge to Implement	Customer Disruption
Provide shelter for displaced employees and their families	$ 0.2 million	LIPA service territory	1 year	Low	None
Arrange temporary daycare for employee children and elderly dependents	$ 0.2 million	LIPA service territory	1 year	Low	None
Stockpile materials that employees could use for temporary repairs to their homes	$ 0.5 million	LIPA service territory	1 year	Low	None
Total	$ 0.9 million				

Ensure all contracts address contractor storm response

Vulnerability:
Low turn-out of contractors following the storm.

A strong turn-out of contractors who provide essential services is critical during the initial stages of the restoration process.

Possible Mitigation Initiatives:
- Modify contracts to include incentives and penalties for contractor storm response. This initiative is currently under investigation by KSE.

Estimated Cost	$2 million		
Improvement for severe storms	3	Challenge to implement	5
Routine benefit	4	Total weighted score	38

Mitigation Detail	Estimated Cost	Scope of Customer Benefits	Time to Implementation	Challenge to Implement	Customer Disruption
Modify contracts to include incentives and penalties for contractor storm response	$ 2 million	LIPA service territory	1 year	Low	None

LIPA can make improvements to restore service more quickly.

Can the system be improved to facilitate quicker restoration?	Yes, improvements to information systems used to facilitate the restoration processes can facilitate quicker restorations by improving the efficiency and effectiveness of the restoration efforts.
Can LIPA effectively apply resources quicker to restoration?	Yes, anticipating employees' housing and family emergencies needs can improve employee turn-out immediately following the storm. Modifying existing contracts, with maintenance and construction services companies, can ensure their timely response in case of a storm.
Can operations be improved to reduce restoration time?	Yes, improvement to restoration processes can facilitate quicker restorations by streamlining the operations, improving decision making, and increasing the efficiency of the resources used in the restoration effort.
Are there existing improvement projects or programs in these areas?	Yes, number of initiatives to improve restoration systems and processes are being studied or are in the early stages of implementation. These initiatives include damage assessment, enhancing communication capacity, improving logistics, and leveraging existing information systems.

PSEG Long Island
Case Name: PSEG LI - Rate Case 2015
Docket No(s): Matter No. 15-00262

Response to Discovery Request: CITY-0071
Date of Response: 04/10/2015
Witness: CAPITAL BUDGETS

Question:
a. With reference to the Panel’s response to City-47, does PSEG currently have a contractual arrangement with the “Massachusetts supplier” for fuel deliveries when there is a shortage in the availability and/or transportation of liquid fuels by “the contracted fuel supplier for Long Island”?
b. If the answer to (a) is in the affirmative, please explain the contractual arrangement.
c. If the answer to (a) is in the negative, please explain why not.

Attachments Provided Herewith: 0

Response:
a. No

b. N/A.

c. PSEG Long Island is negotiating with an alternate supplier for diesel fuel, gasoline, emergency fueling equipment, and transportation and storage services. It is anticipated that the proposed supplier will secure the products specified above and provide ancillary equipment and personnel from a network of qualified subcontractors.

PSEG Long Island
Case Name: PSEG LI - Rate Case 2015
Docket No(s): Matter No. 15-00262

Response to Discovery Request: CITY-0072
Date of Response: 04/10/2015
Witness: CAPITAL BUDGETS

Question:
With reference to the Panel's response to City-35, please provide a detailed timeline for the development and implementation of distribution system storm hardening projects that are planned for the Rockaway Peninsula.

Attachments Provided Herewith: 0

Response:
PSEG LI's prior response to City-28 details the current schedule for the field inspection and engineering of hardening projects to complete by YE 2015 for distribution circuits in the FEMA program.

The FEMA grant requires that circuits, to the extent practical, be worked on in the sequence of their ranking based on total customer interruptions between 2010 and 2013. This priority ranking was provided in response to City-31. Since engineering has yet to commence, detailed schedules for construction work cannot be developed; however, field construction will be started in 2015 on a limited number of the highest priority circuits and with the majority of the circuits being worked in 2016 and 2017. Based on the availability of manpower and materials, some circuit work might be completed in 2018.

PSEG Long Island
Case Name: PSEG LI - Rate Case 2015
Docket No(s): Matter No. 15-00262

Response to Discovery Request: CITY-0073
Date of Response: 04/10/2015
Witness: CAPITAL BUDGETS

Question:
Please explain why there currently are no plans to harden the 69 kV transmission and substation facilities that serve the Rockaway Peninsula.

Attachments Provided Herewith: 0

Response:

Currently the hardening efforts (upgrading the transmission lines and substations to withstand 130 mph winds) are being considered only for new facilities or for the expansion of existing facilities. However, as part of the post Super Storm Sandy repair efforts, elevated foundations were incorporated into the design of the 33 kV and 13 kV equipment located in the Rockaways.

PSEG Long Island
Case Name: PSEG LI - Rate Case 2015
Docket No(s): Matter No. 15-00262

Response to Discovery Request: CITY-0074
Date of Response: 04/15/2015
Witness: CAPITAL BUDGETS

Question:
a. Please confirm that current storm hardening work focuses exclusively on assets that were compromised during Hurricane Sandy and are eligible for reimbursement by the current FEMA grant.
b. If confirmed, please fully explain why PSEG is not undertaking storm hardening projects that are ineligible for FEMA reimbursement and specify:
i. when PSEG and/or LIPA will begin planning storm hardening projects that do not rely on reimbursement from the current FEMA grant; and
ii. when work will commence on storm hardening projects that do not rely on reimbursement from the current FEMA grant.
c. If not confirmed, please specify the current storm hardening projects in the Rockaway Peninsula that are not eligible for FEMA reimbursement.

Attachments Provided Herewith: 0

Response:

a. The FEMA grant stipulates that only distribution, transmission and substation facilities damaged by Superstorm Sandy are eligible for reimbursement. FEMA has further defined the eligibility of areas for the distribution upgrades as the areas of circuits that have the greatest amount of damage (as measured by the numbers of customers interrupted) by storms over the last four years including Sandy and Irene events which were both FEMA reimbursable events to LIPA. See also response to subpart b.

b. The determination to focus on distribution circuits that are eligible for FEMA funded mitigation, the substations that were flood damaged in Sandy, and the transmission lines damaged in Sandy that will be reinforced with the FEMA grant dollars is consistent with what PSEG LI would have proposed for storm hardening investment. Beyond the FEMA program investments, PSEG LI is still making additional investments in storm hardening through the incorporation of storm hardened design standards in transmission line installations, substation installations and distribution system installations. Further, PSEG LI continues to fund worst performing circuit upgrades such as the Circuit Improvement and the Multiple Customer Outage programs which are earmarked to improving reliability.

    i & ii. The FEMA grant is the largest grant ever made by FEMA to any utility and requires significant resources to administer. New and upgrade construction work on non-FEMA targeted facilities will continue to be done to storm hardened criteria where appropriate. This includes all transmission lines and substations in flood prone areas. Distribution facilities will primarily be targeted and hardened under the FEMA program due to the scope of this program.

c. Hardening work to provide flood protection to critical substation equipment at the Far Rockaway, Rockaway Beach and Arverne Substation is continuing. This work has been funded by multiple sources, which include insurance recovery, the FEMA's storm hardening grant and LIPA's budget. The FEMA grant is designed to cover the elevation of the equipment costs. Other funding sources (insurance and the approved budget for capital construction) will cover replacement of damaged equipment.

PSEG Long Island
Case Name: PSEG LI - Rate Case 2015
Docket No(s): Matter No. 15-00262

Response to Discovery Request: CITY-0077
Date of Response: 04/17/2015
Witness: CAPITAL BUDGETS

Question:
With reference to page 34 of the Panel's pre-filed direct testimony, please explain in detail how the $9.82 million cost to elevate substation equipment was estimated. Please provide all supporting workpapers, reports, analyses, communications and any other documentation that demonstrates the basis for this estimate.

Attachments Provided Herewith: 1
2014-02-21 FEMA-NYS-LIPA LOU PA Grants (Executed).pdf

Response:
There were 12 LIPA-owned substations damaged by Superstorm Sandy flooding, and two of those have since been retired. National Grid estimated that it would cost $1 million per substation to raise the necessary equipment. This estimate was conveyed to FEMA and presumably was used in FEMA's benefit-cost analysis, which was not shared with LIPA or PSEG-LI. FEMA's $9.82 million grant corresponds roughly to the cost to elevate equipment at the 10 non-retired damaged substations as estimated by National Grid.

The conditions and details of the FEMA grant are contained in a February 20, 2014 Letter of Understanding among FEMA, New York State and LIPA, a copy of which is being provided herewith.

U.S. Department of Homeland Security
Washington, DC 20472

FEMA

February 20, 2014

Jerome Hauer
Commissioner & Alternate Governor's Authorized Representative
NYS Division of Homeland Security for Emergency Services
1220 Washington Avenue
Building 22, Suite 101
Albany, NY 12226-2251

Tom Falcone
Chief Financial Officer
Long Island Power Authority
333 Earle Ovington Blvd. Ste. 403
Uniondale, NY 11553
516-719-9847

Gentlemen:

This letter of undertaking confirms the understanding that was reached on February 20, 2014, between the Federal Emergency Management Agency ("FEMA"), the State of New York (the "Grantee"), and Long Island Power Authority (LIPA or the "Sub-grantee") (hereafter collectively, "the Parties") related to LIPA's request for Public Assistance ("PA"). LIPA is a corporate municipal instrumentality of the State and sustained damage to its transmission and distribution infrastructure ("T&D infrastructure") varying in degree and severity at more than 21,000 locations and twelve (12) substations as a result of Hurricane Sandy (FEMA-DR-4085). This letter specifically sets out the terms and conditions of an alternative procedures pilot project which is a fixed, capped PA grant authorized under Section 428, 42 U.S.C. § 5189f, of the Robert T. Stafford Disaster Relief and Emergency Assistance Act ("Stafford Act").

Please confirm the terms outlined below by signing and returning this letter at your earliest convenience. Upon receipt, FEMA will work with you to amend, develop, and execute the supporting Project Worksheets (PW) 00367 and 00473 in accordance with 42 U.S.C. § 5189f and the terms of this letter of undertaking.

Primary Essential Elements

1. The Parties have agreed upon the damages caused as a direct result of Hurricane Sandy, the associated dimensions, a detailed description of those damages, and an eligible scope of work that will be captured in the PW that FEMA will generate for this facility.

2. Table 1 reflects the estimates agreed upon by the Parties in accordance with 42 U.S.C. 5189f(e) for a total of **$704,507,766** comprised of LIPA's eligible repair/restoration costs, inclusive of codes and standards upgrades, to its T&D infrastructure and secondary service drops, along with the 12 damaged substations.

Permanent Repair Work Description	**Estimated Cost**
Overhead Electric Distribution System Repairs	$554,706,204
Off Island Crew Support	$80,081,182
Substations, Transmission and Underground Distribution System	$69,000,000
Electric Meter Replacements	$720,380
TOTAL	**$704,507,766**

Table 1 – Estimated permanent repair costs

3. LIPA will accept a fixed, capped Public Assistance Grant for the agreed-upon disaster damages and eligible scope of work for this project under the alternative procedures pilot program authorized under Section 428 of the Robert T. Stafford Disaster Relief and Emergency Assistance Act, codified in 42 U.S.C. § 5189f. The terms of this project will be subject to Public Assistance Alternative Procedure Pilot Program Guide for Permanent Work.

4. Table 2 reflects the Section 406 hazard mitigation proposal (HMP) agreed upon by the parties subject to the terms of this letter of undertaking, and based on the benefit-cost analysis described below for a total of **$729,695,000,** comprised of LIPA's Section 406 hazard mitigation measures:

Mitigation Measure	**Unit Cost**	**Quantity**	**Estimated Cost**
Strengthen damaged transmission lines to 130 mph level of protection	*Very limited quantities anticipated based on Sandy damages*		$5,000,000
Elevate substation equipment damaged during Sandy	*Based on latest estimate from LIPA*		$9,820,000
Strengthening priority mainline circuits damaged during Sandy (storm harden and/or extend poles to reduce exposure to tree/tree limb damage)	$625,000 per mile	1025 miles	$640,625,000
Install Automatic Sectionalizing Unit (ASU)	$55,000 per ASU	1350 units	$74,250,000
TOTAL			**$729,695,000**

Table 2 – Proposed mitigation measures and estimated costs

a. FEMA performed a benefit-cost analysis based upon the estimated Sandy-related damages (including physical damage and loss of function) to LIPA's T&D infrastructure and secondary service drops, along with the 12 damaged substations. In addition, pursuant to the guidelines for the FEMA-approved Benefit Cost Analysis module, FEMA exercised its discretion to include consideration of similar damages from Hurricane Irene (FEMA-DR-4020), and a March 2010 storm (FEMA-DR-1899). In this analysis, FEMA considers the circuits damaged as a direct result of these disasters and susceptible to repetitive loss. Consequently, these circuits are at least three (3) or more times as vulnerable as the additional similarly designed 3-phase primary main lines, supported by outage data provided by LIPA. Based on this consideration, FEMA assigned a higher potential risk-reducing benefit for mitigation of those elements that are especially susceptible to future harm.

b. FEMA's benefit-cost analysis demonstrates that the mitigation measures outlined in Table 2 will reduce future damages and loss of function by a rate of twenty percent (20%) as applied to the 1,025 miles of circuits that LIPA identified as the most vulnerable sections of the Sandy damaged T&D circuits.[1]

c. Accordingly, LIPA agrees to mitigate the damaged portions of its infrastructure consistent with the proposed Section 406 hazard mitigation scope or through a combination of mitigation measures that will achieve at least the same 20% risk-reduction benefit described above.[2]

5. The Parties agree that the grant will be based upon a fixed estimate and capped at **$1,434,202,766**, which includes **$704,507,766** for repair/restoration costs and **$729,695,000** for Section 406 hazard mitigation costs.

6. The Parties acknowledge that the **$704,507,766** for repair/restoration and **$729,695,000** for Section 406 hazard mitigation, agreed upon by the Parties reflect 100% of the total agreed upon funding, which includes the 90% federal cost-share and the 10% State cost-share.

7. The State and LIPA agree to establish and commit to a maintenance and easement management plan for all easements/right-of-ways and circuits captured within the PW developed to execute this fixed, capped Public Assistance Grant. The Parties agree the State shall submit the plan to FEMA before FEMA obligates the PW under this Agreement.

[1] LIPA supported this assertion with historical damage documentation.

[2] For example, provided it meets certain conditions, LIPA may choose to implement selective underground conversions of the existing mainline in lieu of the proposed storm hardening/strengthening measures or extension of poles to reduce tree exposure. Those conditions include using selective underground conversions to mitigate sections of the infrastructure damaged during Sandy that result in the greatest number of customer outages when damaged and are most vulnerable to tree fall based on historic repetitive damage due to tree fall. If LIPA selects strategic undergrounding, then LIPA's underground conversion must include at least 275 miles of strategic undergrounding and alteration of the most susceptible, repetitively damaged locations in order to match the FEMA-calculated benefits associated with the proposed measures of storm hardening/strengthening to the 1,025 miles most vulnerable sections of the Sandy damaged T&D circuits. Thus, LIPA may choose to implement a combination of underground conversions and hardening/strengthening overhead lines, but the sum of all mitigation measures employed must still achieve a risk reduction benefit greater than or equal to a twenty percent (20%) reduction in damages or loss of function in a future event.

8. The Parties agree that, in any future Stafford Act event, if FEMA determines that LIPA (or any successor organization) has not consistently implemented the maintenance and easement management plan described in paragraph 5(c) in good faith thereby contributing to future damage, then FEMA may determine that future damage sustained in or near such easements/right-of-ways and circuits is ineligible for assistance.

9. FEMA acknowledges that the State and LIPA will have flexibility to implement the fixed capped grant in the manner that they deem appropriate to achieve the intended benefit of the agreed upon repair/restoration scope of work, provided the State and LIPA mitigate the most vulnerable/repetitively damaged circuits first. If circuits have equivalent damage history, then the State and LIPA agree to prioritize mitigation based on the density of the population served by each circuit.

10. The Parties acknowledge that all required environmental compliance reviews will be performed based on the agreed upon repair/restoration and 406 hazard mitigation proposal scope of work. Accordingly, the State must inform FEMA of any proposed changes in the agreed upon scope of work that do not substantially conform to the design, function, and location of the damaged facilities so that FEMA can determine whether additional environmental review must be conducted to ensure compliance.

11. In order to complete all required environmental reviews, verify that the mitigation measures meet the required reduction of future damages or loss of function by twenty percent (20%) as outlined in paragraph 4(b) of this letter, obligate funding, FEMA requires and LIPA agrees to provide FEMA with the following documentation:

    i. A spreadsheet or other appropriate summary identifying the circuits that will be mitigated, describing Sandy damages for each circuit, and documenting exact locations of proposed project work (latitude & longitude required for environmental and historic preservation review purposes).

    ii. LIPA's basis for selecting the mainline circuits for mitigation as well as the mitigation measure selected. When documenting the vulnerability of a priority circuit include:
        1. The population served by each circuit;
        2. The damage that was sustained by each (including historical event outages, customer interruptions (CI), and customer minutes interruption (CMI)); and
        3. Any and all critical facilities powered by the circuit.

12. The State and LIPA acknowledge that, in accordance with Section 312 of the Stafford Act, and 44 C.F.R. § 206.191, because they are accepting this fixed, capped PA grant, they will not receive any additional PA funding for Sandy related damages to any facility and/or site. Additionally, if LIPA receives any insurance proceeds that were not originally contemplated in calculating the amount of the fixed, capped grant, FEMA may take reductions in the amount of actual insurance proceeds before the PW is finalized.

13. In accordance with 42 U.S.C. § 5189f (f), FEMA has the authority to waive, as necessary, any regulation regarding the replacement of eligible flood-damaged elements of LIPA's system not consistent with this approach and will carry out the proposed alternative procedure as a pilot program for LIPA for FEMA-DR-4085.

14. The State and LIPA will agree to waive any and all rights to bring appeals pursuant to 44 C.F.R. § 206.206 or requests for arbitration pursuant to 44 C.F.R. § 206.210 (the Dispute Resolution Pilot Program authorized by Section 1105 of the Sandy Recovery Improvement Act) against FEMA based on, arising out of, or by reason of any or all of the conditions set forth in this letter, except for future eligibility determinations arising from paragraph 8, which the Parties agree will be subject to any appeal, arbitration, or similar rights that may be available at the time of such future determinations.

15. FEMA will de-obligate funding awarded in compliance with this agreement and memorialized in the appropriate PWs only upon a determination of fraud, waste, or abuse, or at the direction of the designated audit follow up official for the Department of Homeland Security/FEMA. FEMA recognizes that any subsequent determination that de-obligates funding associated with the determinations made herein and memorialized in the appropriate PW could constitute a new dispute subject to appeal under 44 C.F.R. § 206.206 or arbitration under 44 C.F.R. § 206.210 (provided the circumstances of the dispute meet the requirements for arbitration articulated in that section).

Upon receiving the State's and LIPA's signed confirmation of this letter of undertaking, FEMA will amend Project Worksheet 00367 resulting in a fixed, capped Public Assistance Grant for the agreed upon total of **$1,434,202,766**, which will include, at a minimum, all of the flexibilities of 42 U.S.C. § 5189f (e)(1).

Sincerely,

Brad J. Kieserman
Chief Counsel
Federal Emergency Management Agency

Letter of Undertaking for LIPA

By signing below, the parties confirm their understanding of and their agreement to the primary essential elements of this undertaking as set forth above:

New York State:

______________________________ 2/21/14
Jerome Hauer — Date
Alternate Governor's Authorized Representative
State of New York

LIPA:

______________________________ 2/21/2014
Date

Tom Falcone
Chief Financial Officer
Long Island Power Authority

PSEG Long Island
Case Name: PSEG LI - Rate Case 2015
Docket No(s): Matter No. 15-00262

Response to Discovery Request: CITY-0078
Date of Response: 04/17/2015
Witness: CAPITAL BUDGETS

Question:
With reference to page 34 of the Panel's pre-filed direct testimony, please explain in detail how the $640.625 million cost to strengthen priority mainline distribution circuits was estimated. Please provide all supporting workpapers, reports, analyses, communications and any other documentation that demonstrates the basis for this estimate.

Attachments Provided Herewith: 0

Response:
As was agreed on April 3, 2015, between counsel for the City of New York and PSEG LI, we are providing information that explains how the referenced cost estimate was derived.

FEMA's grant of $640.625M to strengthen priority mainline distribution circuits is based on benefit-cost analysis performed by FEMA, which FEMA has not provided to LIPA or PSEG LI. The conditions and details of the FEMA grant are contained in a February 20, 2014 Letter of Understanding to LIPA attached to our response to Discovery Request CITY-77.

PSEG Long Island
Case Name: PSEG LI - Rate Case 2015
Docket No(s): Matter No. 15-00262

Response to Discovery Request: CITY-0079
Date of Response: 04/17/2015
Witness: CAPITAL BUDGETS

Question:
With reference to page 34 of the Panel's pre-filed direct testimony, please explain in detail how the $74.3 million cost to install up to 1,350 Automatic Sectionalizing Units was estimated. Please provide all supporting workpapers, reports, analyses, communications and any other documentation that demonstrates the basis for this estimate.

Attachments Provided Herewith: 1
Copy of 2014 ASU Costs.xls

Response:
As was agreed on April 3, 2015, between counsel for the City of New York and PSEG LI, we are providing information that explains how the referenced cost estimate was derived.

FEMA's grant of $74.3 million to install up to 1,350 Automatic Sectionalizing Units appears to be based on LIPA's estimated cost of $55,500 per Automatic Sectionalizing Unit ("ASU") to install a single new ASU on the existing distribution system, exclusive of any costs that may be required to expand the existing communication and operating infrastructure, which had been provided to FEMA at their request. The quantity of 1,350 was determined by FEMA. See attached spreadsheet for further information on ASU costs.

2014 RELIABILITY ASU ACTUAL COSTS FOR FULL INSTALLATION

ASU	Reliability	Radio DCA	Rpt #	Serial #	Maximo Number	Grid	Proposed Location	Circuit	Norm Position	LABOR	BURDEN	MATERIAL	SERVICES	TOTAL
ASU-2033	2014 Reliability Program - Woodbury Sub	DCA1	Hicksville Rptr 9067-1710	14-20168	T101570191	031-10-9035	Install N/C ASU on Manetto Hill Road s/o Sally Lane and n/o Central Park Road.	5L-6H3	N/C	$5,019	$3,689	$35,271	$5,275	$49,254
ASU-2036	2014 Reliability Program - Plainedge Sub	DCA3	Massapequa Rptr 7-9710	14-20175	T101570198	032-23-5468	Replace LBD-6927 (P# 16) on North Baldwin Road n/o North Virginia Avenue w/ N/C ASU.	5G-109	N/C	$8,998	$5,547	$36,549	$3,052	$54,146
ASU-4102	2014 Reliability Program - Miller Place/Port Jeff	DCA 2	Port Jeff-Rptr 44-9810	14-20177	T101576556	060-46-8887	Replace LBS-6166 with N/O ASU (P# 62) on Old Post Road w/o Lookout Ridge Drive.	8M-5P7/8F-706	N/O	$6,082	$4,055	$37,408	$5,080	$52,625
ASU-4105	2014 Reliability Program - Culloden Point	DCA 3	Hither Hills--Rptr 51-1710	14-20152	T101576567	134-17-9629	Replace LBS-4117 with N/C ASU (P# 15) on Greenwich Street n/o Gloucester Avenue.	9K-976	N/C	$479	$296	$34,471	$19,939	$55,185
ASU-4118	2014 Reliability Program - Nesconset Sub	DCA 2	Bald Hill-Rptr 52-4710	14-20153	T101578380	054-62-7081	Replace LBS-5541 (P# 140) with a N/O endpoint ASU (P# 190) on Middle Country Road w/o Parsnip Pond Road.	6L-4H8/6L-964	N/O	$0	$0	$32,454	$29,249	$61,703

AVERAGE $54,582.60

NOTE 1: Work Integration Team furnished the cost data for actual 2014 ASU Installations

Revised:	5/1/15

2014 ASU/ACR PROJECT TRACKER

Q-NASSAU						
			Proposed			
ASU	C&R Project	CEM #	Grid	New Location Details	Circuit	Comments

CENTRAL						
			Proposed			
ASU	C&R Project	CEM #	Grid	Location Details	Circuit	Comments

W-SUFFOLK						
			Proposed			
ASU	C&R Project	CEM #	Grid	Location Details	Circuit	Comments

E-SUFFOLK						
			Proposed			
ASU	C&R Project	CEM #	Grid	Location Details	Circuit	Comments

LEGEND: 2014 C&R Project

PSEG Long Island
Case Name: PSEG LI - Rate Case 2015
Docket No(s): Matter No. 15-00262

Response to Discovery Request: CITY-0080
Date of Response: 04/17/2015
Witness: CAPITAL BUDGETS

Question:
With reference to page 34 of the Panel's pre-filed direct testimony, please explain in detail how the $5.0 million cost to strengthen damaged transmission lines was estimated. Please provide all supporting workpapers, reports, analyses, communications and any other documentation that demonstrates the basis for this estimate.

Attachments Provided Herewith: 0

Response:
As was agreed on April 3, 2015, between counsel for the City of New York and PSEG LI, we are providing information that explains how the referenced cost estimate was derived.

FEMA's grant of $5 million to strengthen damaged transmission lines is based on FEMA's benefit-cost analysis performed by FEMA, which FEMA has not provided to LIPA or PSEG LI. PSEG LI did not provide any input (cost per unit or otherwise) into the creation of this portion of the grant.

PSEG Long Island
Case Name: PSEG LI - Rate Case 2015
Docket No(s): Matter No. 15-00262

Response to Discovery Request: CITY-0082
Date of Response: 04/10/2015
Witness: CAPITAL BUDGETS

Question:
Is LIPA or PSEG examining how to harden the transmission interfaces with the Consolidated Edison service territory? If so, please explain how PSEG intends to harden those interfaces, and provide a timeline for the development and completion of all such work. If not, please explain why not.

Attachments Provided Herewith: 0

Response:
PSEG LI is not currently considering hardening transmission interfaces with Con Edison, as these interfaces are comprised of underground cables connected to substations that are not at risk for flooding.

PSEG Long Island
Case Name: PSEG LI - Rate Case 2015
Docket No(s): Matter No. 15-00262

Response to Discovery Request: CITY-0083
Date of Response: 04/10/2015
Witness: CAPITAL BUDGETS

Question:
Has LIPA or PSEG discussed with Consolidated Edison what measures that utility is taking to harden assets on its side of the transmission interfaces? If so, please explain what measures Con Edison is implementing to improve the resiliency of the interfaces between the two systems. If not, please explain why not.

Attachments Provided Herewith: 0

Response:
See PSEG LI's response to Discovery Request CITY-0082.

PSEG Long Island
Case Name: PSEG LI - Rate Case 2015
Docket No(s): Matter No. 15-00262

Response to Discovery Request: CITY-0086
Date of Response: 04/10/2015
Witness: CAPITAL BUDGETS

Question:

With reference to the Panel's response to City-60, please define the phrase "sufficiently hot weather". Please include in your response the temperature threshold used to distinguish "sufficiently hot weather" from other weather.

Attachments Provided Herewith: 0

Response:

At a minimum, the regression model developed to estimate the normal weather adjustment to the actual peak load should include at least one day when the actual peak load occurred at a temperature that reached the normal level of 90.3 degrees F for the peak hour. Ideally, the model will include several days when the experienced weather conditions exceeded normal. If needed, data from previous summers may be included to produce a distribution that is judged to be valid.

PSEG Long Island
Case Name: PSEG LI - Rate Case 2015
Docket No(s): Matter No. 15-00262

Response to Discovery Request: CITY-0089
Date of Response: 05/05/2015
Witness: CAPITAL BUDGETS

Question:
a. Has PSEG or LIPA completed any project(s) to harden substation control houses?
b. If the answer to (a) is in the affirmative, please identify and detail each such project, including the name and location of each substation.
c. If the answer to (a) is in the negative, please (i) explain why such projects have not been completed, and (ii) specify whether PSEG intends to undertake such projects and, if so, when such work will commence.

Attachments Provided Herewith: 0

Response:

a. Yes

b. The following is a list of the projects:
- Park Place Substation –Park Place, NY – Replacement control house was installed on elevated foundation.
- Rockaway Beach Substation –Queens, NY - Replacement control house was installed on elevated foundation
- Arverne Substation –Queens, NY - 33kV Control equipment enclosure will be replaced as part of the 38kV switchgear replacement, with elevated foundation. Planned for completion Spring 2016.
- Far Rockaway Substation –Queens, NY - 33kV control equipment enclosure will be replaced as part of the 38kV switchgear replacement, with elevated foundation. Planned for completion Spring 2017.
- Woodmere Substation –Woodmere, NY - Replacement control house planned for installation on elevated foundation. Planned for completion Spring 2017.
- Far Rockaway Substation –Queens, NY - Replacement control house planned for installation on elevated foundation. Planned for completion Spring 2018.

c. N/A.

Long Island Power Authority
Case Name: PSEG LI - Rate Case 2015
Docket No(s): Matter No. 15-00262

Response to Discovery Request: CITY-0090
Date of Response: 05/11/2015
Witness: Thomas Falcone

Question:
With reference to the answer provided in response to City-68, please explain whether the Navigant report was presented to the LIPA Board of Trustees. Please include in your response the date on which such presentation was made, and please explain all actions taken by the Board of Trustees in response to the report.

Attachments Provided Herewith: 3

Response:
Upon information and belief, the LIPA Board of Trustees was briefed on the storm hardening program set forth in the Navigant report provided in response to City-68 during the October 18, 2006 meeting. Minutes of the October 18, 2006 meeting are available at http://www.lipower.org/pdfs/company/papers/minutes/101806.pdf.

The Board and the Operations Committee of the Board received updates on implementation of the storm hardening program from time to time, including in January 2012, December 2012, and June 2013. Copies of those presentations are attached.

LIPA
Long Island Power Authority

Update on LIPA's Storm Hardening Initiatives 2007-2012

Operations Committee of LIPA Board of Trustees

December 17, 2012

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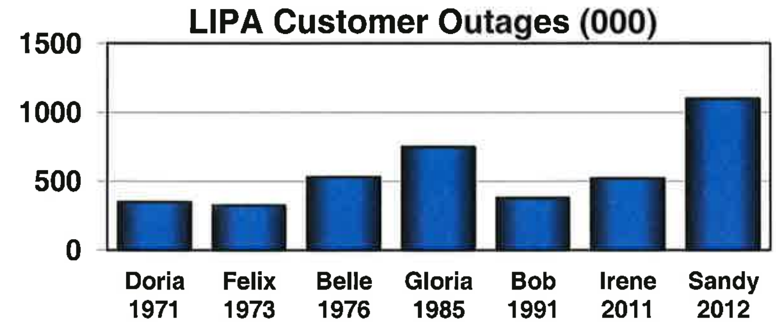
Table of Contents

Executive Summary

Storm Hardening Policy and Plan Development

- In 2007, LIPA launched a $500-million, 20-year program to "harden" its transmission and distribution system damage from severe storms, and improve restoration time.



- "Withstanding Severe Storms: Policy and Program Summary" (October 17, 2006) summarized LIPA's three-pronged approach to its storm hardening policy. Areas of focus include: durability, resilience, and restoration.

Can LIPA improve system performance and service quality in response to severe storms?

DURABILITY	RESILIENCE	RESTORATION
Can LIPA "harden" the system to avoid damage and/or outages?	Can LIPA enhance system flexibility to deliver service in spite of damage?	Can LIPA restore service to more customers more quickly?

Executive Summary
Update on Progress

Long Island Power Authority

- Navigant performed a study for LIPA in 2006 to evaluate Storm Hardening best practices among utilities, and develop recommendations on specific initiatives for LIPA.
  - Prior to 2006, the primary utilities addressing storm hardening for hurricanes were those in Florida and the Carolinas. Other regions were evaluating mitigation measures for winter storms and icing.
- Developing the report was a collaborative effort between Navigant, LIPA, and KeySpan.
- Over two dozen initiatives to enhance the system's ability to withstand and recover from Category 3 hurricanes were identified for potential application on Long Island. To implement all initiatives at locations most vulnerable were estimated to cost approximately $3B.
- LIPA's VP of Operations and CFO determined that a reasonable investment for storm hardening would be $500M over 20 years or $25M per year to have no rate impact and to achieve reasonable benefit.
  - Initiatives were then prioritized for implementation.

Executive Summary
Update on Progress *(cont'd)*

LIPA
Long Island Power Authority

- Since 2007, presentations on storm hardening progress have been provided to LIPA's Board – the last of which was January 2012.
- Navigant's review looks at each specific initiative identified in 2006, and provides a scorecard on the progress.
  - Twenty-five specific initiatives were identified in 2006.
  - Of those, nineteen (19) are in progress, one (1) has been completed, and five (5) have not been started.
  - In addition to the explicit initiatives, LIPA has also been instrumental in getting Storm Hardening included in the New York State Energy Planning process and participated in the 2012 EPRI initiative on best practices in Storm Hardening.
- LIPA is finishing year six of a 20-year program. Overall, LIPA is approximately 25% completed with the investment plan.
  - The January 2012 report to the Board indicates that approximately $125M has been spent on storm hardening activities through November 2011. [Navigant has not independently verified this amount.]
  - It was recognized in 2006 that the program was not intended to rebuild the entire system, but was to strengthen the system's ability to withstand and recover from severe storms.

Executive Summary
Status of Durability Initiatives

Long Island Power Authority

- Eight of ten durability initiatives, designed to minimize the damage caused by severe storms, are in-progress.

ID Number	Recommendation	Status
D1	Reconfigure substations to avoid equipment damage during flooding	
D2	Reconfigure substations to avoid equipment damage from high winds	
D3	Harden substation control houses and outdoor control equipment to withstand high winds, rain and flooding	
D4	Reduce the impact of tree contact on non-ROW (roadside and LIRR) transmission at voltages of 69 kV and below	
D5	Strengthen overhead transmission to withstand high winds	
D6	Enhance transmission structure inspection programs to reduce structure failure from mechanical overloads	
D7	Reduce the impact of tree contact on distribution in heavily treed areas	
D8	Enhance distribution pole inspection programs to reduce structure failure from mechanical overloads	
D9	Protect padmounted equipment and overhead structures against storm surge	
D10	Protect existing and new underground lines in flood and surge zones.	

Key: Completed In-Progress Not Started

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Executive Summary
Status of Resilience Initiatives

LIPA
Long Island Power Authority

- Two resilience initiatives were identified to minimize the impact of storm damage.
  - LIPA continues to expand and leverage its distribution automation program.
  - Mobile generators and substations are deployed as appropriate.
  - Although generation such as Caithness, and new interconnections, such as Neptune, have been added on Long Island, they do not meet the intended definition of distributed generation as intended for this initiative.

ID Number	Recommendation	Status
F1	Leverage Distribution Automation	In-Progress (yellow)
F2	Distributed or Mobile Generation and Microgrids	In-Progress (yellow)

Key: Completed (green) In-Progress (yellow) Not Started (red)

Executive Summary
Status of Restoration Initiatives

- A new outage management system is among the restoration initiatives that are intended to minimize outage times.

ID Number	Recommendation	Status
R1	Outage Management System	
R2	Improve data and voice communication channels	
R3	Implement a resource control system	
R4	Implement an electronic damage inventory system	
R5	Improve the restoration management system	
R6	Procure insulator washing equipment/services	
R7	Develop restoration plans for each storm and category	
R8	Develop damage prediction model	
R9	Improve damage assessment processes	
R10	Improve logistics processes	
R11	Develop HR support to ensure employee commitment to the restoration effort	
R12	Ensure all contracts address contractor storm response	
R13	Proactively de-energize circuits	

Key: Completed In-Progress Not Started