Synapse
Energy Economics, Inc.

# A Clean Electricity Vision for Long Island

## Supplying 100% of Long Island's Electricity Needs with Renewable Power

August 29, 2012

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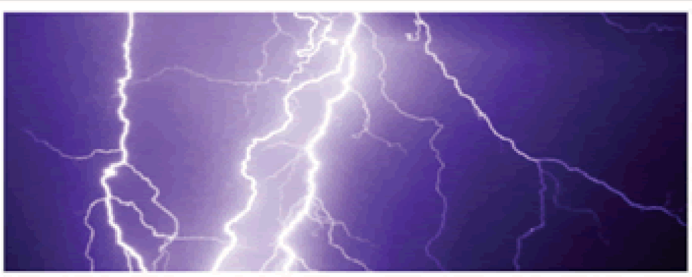

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# 1. Introduction

In recent years a number of cities and states worldwide have established aggressive renewable energy targets. For example:

- San Francisco's mayor has called for the city to supply 100% of its electricity needs from renewable energy sources by 2020, and the city has formed a task force to develop an implementation plan.[1]
- The German city of Munich plans to serve all residential demand and the subway/tram system with renewable power by 2015, and all demand by 2025.[2]
- In July of 2011, the Scottish government announced its Routemap for Renewable Energy in Scotland 2011 which sets a target for "the equivalent of all of Scotland's electricity needs to come from renewables by 2020".[3]
- Under a Danish government plan announced November 25, 2011, 100% of Denmark's electricity and heat would come from renewable energy by 2035. By 2050, the entire energy supply -- electricity, heat, industry and transportation -- would come from renewables, according to the plan.[4]

To be clear, renewable energy targets like these typically use an accounting framework in which some fossil-fueled electricity is used during certain hours of the year, and it is offset by additional renewable generation or the purchase of Renewable Energy Credits (RECs).

This study focuses on an aggressive move to renewable energy – and energy efficiency – on Long Island. The study was commissioned by Renewable Energy Long Island and other member organizations of the Long Island Clean Energy Roundtable, funded by the Long Island Community Foundation and the Rauch Foundation. The analysis was performed by Synapse Energy Economics.

*This study examines a future in which Long Island generates or contracts for renewable energy sufficient to meet all of its residential electricity needs by 2020 and all of its electricity needs by 2030.*

Specifically, this study examines a future in which Long Island generates or contracts for renewable energy sufficient to meet all of its *residential* electricity needs by 2020 and all of its electricity needs by 2030. The 2030 vision includes the use of some fossil-fueled generation,

[1] See i.e. http://www.care2.com/greenliving/san-francisco-100-renewable-energy-by-2020.html and http://www.sfmayor.org/ftp/archive/mayornewsom/press-room/press-releases/press-release-mayor-newsom-powers-up-californias-largest-municipal-solar-project-at-sunset-reservoir-generating-up-to-5-megawatts-of-clean-energy-daily/index.html

[2] All renewable generators will be owned by the utility and will be located in Munich, other parts of Germany, and in other European countries. The electricity will be fed into the local grid of these respective locations. More at http://www.swm.de/english/company/energy-generation/renewable-energies.html and http://www.swm.de/dms/swm/dokumente/english/projects-renewable-energies-expansion-campaign.pdf http://www.eurosolar.de/en/index.php?option=com_content&task=view&id=426&Itemid=

[3] See http://www.scotland.gov.uk/Resource/Doc/917/0118802.pdf

[4] See i.e. http://www.reuters.com/article/2011/11/25/us-denmark-energy-idUSTRE7AO15120111125.

which is offset by the purchase of Renewable Energy Credits. This "Clean Electricity Vision" (CEV) is compared to a "Reference Case" future, based on the current plan for meeting Long Island's electricity needs. The two scenarios are compared in a detailed spreadsheet analysis, with attention to annual energy requirements, installed capacity requirements and a constrained regional transmission system. The scenarios are compared in terms of the resource mixes, costs and carbon emissions. The CEV would provide benefits in addition to carbon reductions – environmental benefits, local economic development and reduced exposure to fossil fuel prices – but these benefits are not quantified here.

The study provides a first-order look at costs and feasibility. The intent is not to lay out a detailed resource plan, but to inform the discussion of these issues and to prompt further analysis. Both scenarios should be examined with an hourly dispatch model to better understand potential costs associated with variable generation, operating reserves and maintaining system stability.

The sections below present the study's methodology, key assumptions and conclusions. However, we begin by describing the key challenge inherent in a rapid move to renewable electricity.

## A. The Challenge of Peak Loads

Regional power systems must not only provide enough energy to meet demand, they must also be able to accommodate minimum and maximum loads and periods when loads are changing rapidly. While wind and solar energy is abundant, it cannot be dispatched at will like a gas-fired power plant.[5] In order to meet peak loads entirely with renewable energy, a system would have to be dramatically overbuilt, leading to oversupply during off-peak periods, or it would need large amounts of electricity storage capacity. Over the long term, fully renewable power systems with sufficient storage capacity make sense – in fact they may be our only option in the long run. But moving to this paradigm within the next decade or two would be extremely expensive. This is why the more aggressive renewable energy targets typically allow for some fossil-fueled generation.

In the Northeastern U.S., there is a well established system of tradable Renewable Energy Credits (RECs). A certificate is created for each MWh of renewable generation, and these certificates can be purchased with the energy from the generator or they can be purchased separately. The RECs provide an additional source of revenue for renewable power projects, and they ensure that multiple entities do not claim to be buying the same renewable energy. In addition, the price of RECs provides an important market signal which indicates when new renewable energy is in demand.

*The study takes into account several major constraints Long Island would face in achieving these goals, including ISO New England's installed capacity requirements and constrained regional transmission systems.*

In the Clean Electricity Vision laid out here, Long Island would contract for a large amount of renewable energy along with the associated RECs. It would continue to meet a large portion of its

[5] Biomass and geothermal power plants are dispatchable. However, growth in biomass power will be constrained by forest management issues and competition for biofuel from other sectors. In the foreseeable future, geothermal power will play a very limited role outside the western U.S., where geothermal heat is close to the surface.

capacity requirements with fossil-fueled units that operate very little. It would rely on other fossil-fueled units for both capacity and to follow fluctuations in renewable generation. Overall, in 2020 the Island would be meeting nearly 50% of its energy requirement with renewable energy generated on Island or purchased from off Island. This would likely be sufficient renewable energy to serve all residential customers on the Island. By 2030 the Island would be meeting 75% of its annual electric energy needs with a mix of owned and purchased renewable energy. It would meet the remaining 25% of its needs with fossil-fueled generation and purchase an equal amount of RECs to give the Island, in effect, a 100% renewable electricity supply.

## B. Methodology and Key Assumptions

To evaluate the impacts of the Clean Electricity Vision, we developed spreadsheet representations of the current resource plan for the Island and the CEV. We analyze these resource mixes at two points in time: 2020 and 2030. We then compare the two scenarios to estimate the net impacts of the CEV.

Our Reference Case resource mix for Long Island is based on the Long Island Power Authority's (LIPA's) 2010 resource plan and on data from the New York ISO.[6] To develop the Reference Case, we start with projected peak loads and energy requirements for Long Island from the New York ISO document, *2011 Load and Capacity Data*.[7] However, the forecasted energy requirements presented there only account for currently funded efficiency programs. We adjust the energy requirement to create a scenario in which efficiency funding is maintained at roughly current levels throughout the study period. Specifically, we assume energy savings of 0.8% of the energy requirement over the study period. It is important to note that this does not result in demand falling by 0.8% per year. While efficiency programs are operating, load is growing due to increasing population, increasing per-capita plug loads. On average, the energy requirement increases by 1% per year in the Reference Case, after simulating savings of 0.8% per year.

*Energy efficiency is Long Island's most cost effective resource. The total cost of saving a MWh is in the range of $45 to $55, below the cost of any new generating resource.*

We do not simulate increasing electricity demand from electric vehicles or from electrically operated heat pumps. Both of these technologies would reduce the Island's overall carbon impact and are desirable for that reason, but estimating demand growth from them is beyond the scope of this work.

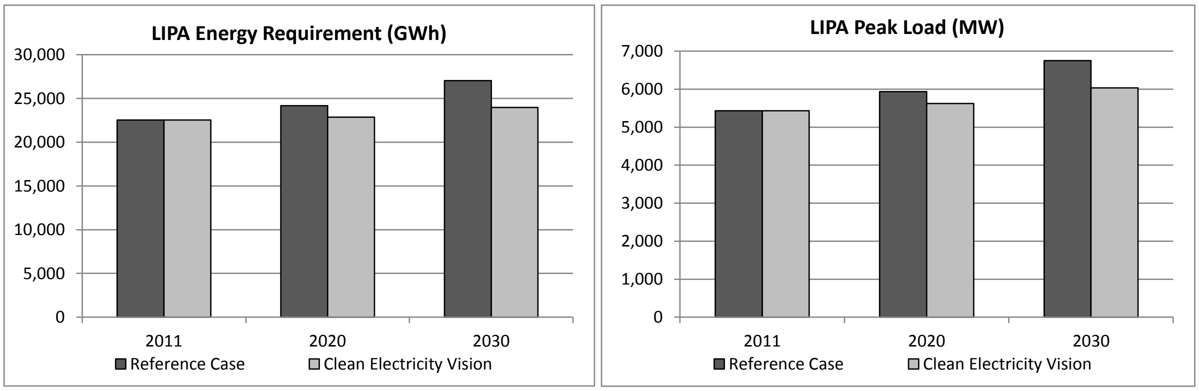
Energy efficiency is Long Island's most cost effective resource by far. Nationwide, the total cost of saving a MWh of energy is in the range of $45 to $55. Further, a number of studies show that a vast energy efficiency potential remains untapped. For the CEV, we adjust the ISO data to simulate a ramp up from current levels to 2% savings in 2022. This level of savings is consistent

[6] Long Island Power Authority, *Electric Resource Plan 2010 – 2020*, February 2010. There are other small load-serving entities on the Island, but LIPA serves a vast majority of the load.
[7] NY ISO, *2011 Load and Capacity Data*, Version 1, April 2011.

with the savings being targeted by the most aggressive efficiency programs in the U.S. today. We maintain savings at 2% of the energy requirement through 2030, resulting in annual average load growth of 0.3%.

Figure 1 shows the Long Island energy requirement and peak loads in our Reference Case compared to the CEV. We have developed our peak load forecasts in the same way as our energy forecast, adjusting the 2011 NY ISO data to approximate LIPA's current resource plan and constructing a CEV with more aggressive energy efficiency.

**Figure 1. Energy Requirements and Peak Loads in the Two Scenarios**




Our assumed cost of energy efficiency is based on a review of LIPA's efficiency programs[8] and on data Synapse maintains regarding utility and third party efficiency programs nationwide. We assume a total cost (including utility and customer costs) of $50 per MWh saved during the period 2012 through 2020. (All costs are presented in constant 2010 dollars.) In the Reference Case we assume savings continue to cost this amount through 2030, but in the CEV, where more aggressive efficiency efforts are assumed, we apply a cost of $55 per MWh. Information available to date suggests that more aggressive efficiency programs have *lower* costs per MWh saved than less aggressive ones. However, no utility has maintained a strong efficiency effort over a period of several decades. Therefore, we make the more conservative assumption that efficiency costs will rise over time in the CEV.

The costs we assume for fossil-fueled plants are based on information provided in Appendix B of LIPA's 2009 Resource Plan, although we have used fuel prices projected by EIA in 2011 rather than those from the 2009 Plan.[9] We use LIPA's base case emission costs for $NO_X$.[10] Capacity factors are applied to resource types to determine energy production and costs per MWh. We assume that a carbon policy is adopted in the U.S. sometime between 2015 and 2020, resulting in the annual carbon prices shown in the mid case of Synapse's 2011 forecast.[11] The average

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[8] Opinion Dynamics Corp., *1999 – 2008 Clean Energy Initiative Assessment Report*, prepared for Long Island Power Authority, May 2010.

[9] We use the forecasted prices of fuels delivered to electric utilities on Long Island in 2020 and 2030 from the 2011 Annual Energy Outlook, published by the U.S. EIA.

[10] $NO_X$ is priced at $1,050/ton in 2020 and $1,275/ton in 2030.

[11] Johnston, Lucy, et. al., *2011 Carbon Dioxide Price Forecast*, Synapse Energy Economics, February 11, 2011, amended August 10, 2011. http://www.synapse-energy.com/Downloads/SynapsePaper.2011-02.0.2011-Carbon-Paper.A0029.pdf

carbon price included for the period 2013-2020 is $5.70 per ton, and the average price between 2021 and 2030 is $35 per ton. For each resource type, capacity factors, levelized and total costs are shown in Tables A3 through A6 in the Appendix.

Table A2 shows our cost and performance assumptions for the key renewable resources. Energy costs are real (i.e., inflation adjusted) levelized costs, based on an assumed inflation rate of 2% over the study period. For photovoltaics (PV), we apply separate costs and capacity factors to three categories: large, ground-mounted projects (>5 MW); commercial projects (averaging 300 kW) and residential projects (averaging 3 kW). For ground-mounted projects, we have increased installed costs by 10% to account for higher installation costs on Long Island and increased fixed O&M by 300% to account for higher land costs.

For onshore wind, we assume a cost of $1,950 per kW throughout the study period, consistent with a 1.6 MW turbine, 80-meter hub height and 100-meter rotor diameter. We assume average capacity factors of 35% for projects added between 2012 and 2020 and 36% for projects added between 2021 and 2030. These capacity factors take into account modeling of the equipment described above in class 3 wind regimes. This modeling suggests that the equipment being installed in 2012 and after will achieve significantly higher capacity factors than projects installed in previous years. Some analysts predict that the larger machines being installed today in moderate wind regimes will achieve capacity factors in the range of 40%.[12] However, because these production rates have not yet been achieved in practice, we use lower rates.

The cost of offshore wind projects over the next decade is more difficult to predict. The first projects developed in the U.S. are likely to cost over $6,000 per kW, with a levelized cost of energy over $200 per MWh. However, we expect costs to fall rapidly with project development, as U.S. developers gain experience and construction and support infrastructure are developed. Current costs in Europe are estimated to be around $4,250 per kW after the installation of over 3,000 MW there.[13] We apply a cost of $5,600 per kW to the first project(s) Long Island purchases from (assumed to be installed by 2020) and a cost of $4,250 per kW to the next project(s) (installed between 2020 and 2030).

For new biomass projects, we assume an installed cost of $4,785 per kW. We use biomass fuel costs from the 2011 Annual Energy Outlook: $2.58 per mmBtu in 2020 and $3.04 per mmBtu in 2030 (converted to $2010). Our energy storage costs are based on projections for Sodium-Sulfur and Lithium Ion batteries. We assume near term costs of $1,300 per kW, falling to $1,040 per kW by 2025. (We do not add storage capacity until after 2020.) Storage losses are assumed to be 10%.

## C. The Resource Mixes

The energy mixes in our Reference Case (RC) and CEV are shown in Figure 2. The details of these resource mixes appear in Tables A3 through A6 in the Appendix. These tables show

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[12] Wiser, Ryan, et al., *Recent Developments in the Levelized Cost of Energy from U.S. Wind Power Projects*, published by NREL and Lawrence Berkeley Labs, February, 2012. http://eetd.lbl.gov/ea/ems/reports/wind-energy-costs-2-2012.pdf

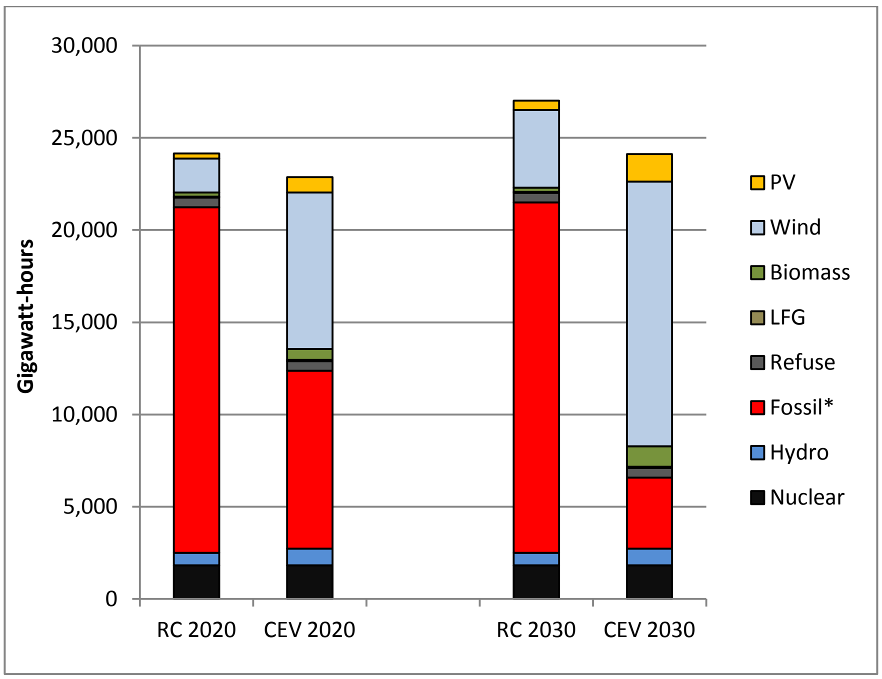
[13] See: NREL, 2010. *Large-Scale Offshore Wind Power in the United States: Assessment of Opportunities and Barriers*. September 2010, NREL/TP-500-40745. See Section 6.

specified amounts of generic resource types, and we indicate whether each resource is located on or off the Island and whether the contract is for energy, capacity or both. They also show the energy production of each resource type, as well as the nameplate capacity and the amount of capacity credited to the NY ISO's Long Island locational capacity requirement (LI LCR).[14]

### *The Reference Case*

In 2020, the Reference Case energy mix is 13% renewable. In 2030, renewables make up 21%. The PV projects located on island and the offshore wind provide both energy and capacity. We assume that all other renewable energy is obtained in the form of long-term contracts for energy and RECs but not capacity.[15] As noted, we add transmission costs to wind sited in Upstate New York and Maine; however these costs are intended to address constraints in those areas, not to allow the projects to provide capacity on Long Island. The Reference Case also includes 1,100 MW of new combined-cycle capacity on the Island, added between 2020 and 2030.

**Figure 2. The Energy Mixes in the Two Scenarios**




*The "Fossil" category includes all known fossil-fueled resources and economy purchases, which we assume to be fossil-fueled.

### *The Clean Electricity Vision*

Figure 2 above also shows the 2020 energy mix in the CEV. In this scenario, the same cost assumptions are used for supply-side resources as in the Reference Case; however costs per

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[14] For several areas of the state, including Long Island, the NY ISO has location-based capacity requirements in addition to its statewide capacity requirements.
[15] The exception to this rule is the Bear Swamp contract, which we understand to be for energy, capacity and RECs.

MWh differ due to different assumed capacity factors. Assumed fuel costs are the same in both scenarios.

*The Clean Energy Vision should be investigated with an hourly dispatch model. Important areas to examine are the accommodation of variable generation, operating reserves and the impact of expanding demand response markets.*

By 2020, Long Island is generating or purchasing renewable energy sufficient to meet 48% of its electricity needs, or approximately all of its residential demand. By 2030, it is meeting 75% of its electricity supply with renewable energy. The vast majority of this energy is from wind. By 2030 there are 2,250 MWs of offshore wind connected directly to the Long Island grid, producing roughly 8,480 GWh per year. The Island is also purchasing 6,190 GWh per year from onshore wind farms (off Island). There are 800 MWs of energy storage capacity on the Island, moving 2,240 GWh per year (equal to 16% of the total wind energy) from off-peak to on-peak periods. There are 900 MWs of PV on the Island, producing nearly 1,500 GWh per year. Smaller amounts of landfill gas, biomass and hydropower are also contributing to the mix.

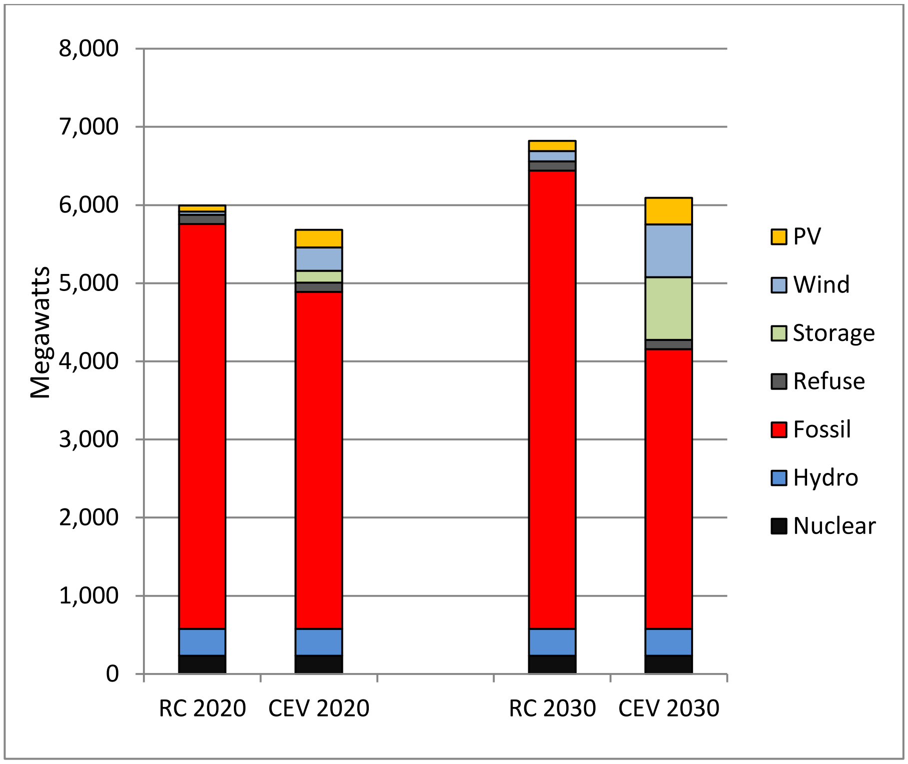
In 2030, in addition to the renewable energy discussed above, Long Island is relying on 6,260 GWhs of fossil or nuclear generation to meet its electricity needs. We include in the CEV the cost of an equal amount of RECs, priced at $25 per MWh.

Figure 3 shows the capacity being used to meet capacity requirements in the two scenarios. For capacity analysis, offshore wind capacity is derated to 30% of nameplate, and PV capacity is derated based on the percentage of PV energy in the resource mix. In both scenarios PV capacity is derated to 44% of nameplate in the 2020. In the CEV in 2030, PV is 6% of the energy mix and is derated to 38% of nameplate capacity.[16] Resources not shown in Figure 3 (such as biomass) are not being used to meet capacity requirements – the purchase is for energy only. Note that, while a considerable amount of fossil-fueled capacity is being used to meet capacity obligations, it is contributing a much smaller fraction of energy (Figure 2).

Note that this analysis does not consider the effects of demand response markets in New York. In these markets, customers are paid a monthly fee to reduce their demand when directed to do so by the power system operators. Demand response reduces peak loads, and it also helps accommodate variable generation. Currently, there are robust and growing demand response markets in New York, New England and PJM, however simulating these markets was beyond the scope of this work.

[16] PV derating is based on: Perez, R., et. al. 2006. *Update: Effective Load-Carrying Capability of PV in the U.S.* National Renewable Energy Laboratory, NREL/CP620-40068.

**Figure 3. The Capacity Mixes in the Two Scenarios**




It is important to note that, while we have tried to make rational choices in developing the CEV, it is not necessarily the optimal scenario. Exploring the impacts of other renewable fuel mixes would be useful future work.

## D. Net Impacts of the Clean Electricity Vision

Table 1 below shows the net costs of the CEV. In each category, costs shown are costs in this scenario minus Reference Case costs. Power supply costs are 23% higher than in the Reference Case in 2020 and 15% higher in 2030.

As indicated in the tables, we define “supply” costs as the sum of energy, capacity, efficiency and REC costs. We assume that the cost of maintaining the T&D system is the same in both scenarios, except that we include distribution system savings of $100 per kW of load reduced by energy efficiency, consistent New York PSC guidelines. Total distribution system savings from efficiency total $31 million annually in 2020 and $71 million annually in 2030. Annual cost impacts are estimated based on levelized resource costs. Actual cost recovery would likely differ for some resources; however this method provides a reasonable estimate of the cost increment attributable to the CEV at different points in time.

**Table 1. Net Power Supply Costs of the Clean Electricity Vision (million 2010$)**

| | 2020 | 2030 |
|---|---|---|
| Net Energy & Capacity Cost | $529 | $242 |
| Net Energy Efficiency Cost | $66 | $185 |
| Net REC Cost | $0 | $155 |
| Total Supply Cost | $595 | $582 |
| % Supply Cost Increment | 23% | 16% |
| Estimated Average Bill Impact | 12% | 8% |

The net costs of the CEV are smaller in 2030 than 2020 for several reasons. First, fossil fuel prices rise over the study period, and this increases costs in the Reference Case more than in the CEV. Second, the costs of new offshore wind and PV projects are assumed to fall over the study period. Third, carbon costs rise over the study period, and the Clean Electricity Vision is less exposed to these costs. And finally, in 2030 the energy requirement and peak load in the CEV are farther below the Reference Case than in 2020, because the higher rate of energy savings from energy efficiency efforts has had a longer time to compound (see Figure 1).

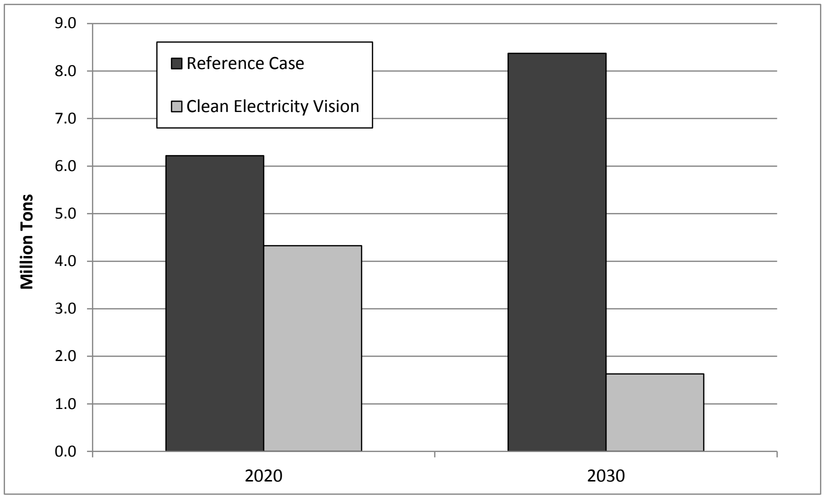
Table 1 also includes a rough estimate of the average bill impacts of the CEV. We have estimated these impacts as the percentage change in LIPA's total costs in the two scenarios. Table 2 shows this calculation. Total costs in 2011 are shown as LIPA's projected 2011 revenue from the Company's 2012 budget presentation. These costs are divided into supply costs and other costs based on fractions also presented in the budget presentation. For 2020 and 2030, we show the total supply cost of each scenario as calculated in our spreadsheets. For non-supply costs in those years, we escalate 2011 non-supply costs at the rate of demand growth in each scenario. (In the CEV, we also include the credit described above for avoided distribution costs from energy efficiency.) We then estimate average bill impacts as the percentage difference in total costs. Therefore, these would be the average impacts across all rate classes.

**Table 2. Estimating Average Bill Impacts (million 2010$)**

| | 2011 | 2020 | 2030 |
|---|---|---|---|
| Reference Case | | | |
| Supply Cost | $1,799 | $2,600 | $3,737 |
| Non-supply Costs | $1,949 | $2,091 | $2,339 |
| Total Costs | $3,748 | $4,691 | $6,076 |
| Clean Electricity Vision | | | |
| Supply Cost | $1,799 | $3,195 | $4,319 |
| Non-supply Costs | $1,949 | $2,060 | $2,267 |
| Total Costs | $3,748 | $5,255 | $6,586 |
| Difference in Total Costs | | $564 | $510 |
| % Difference | | 12% | 8% |

Figure 4 shows the approximate direct $CO_2$ emissions from electricity supply in the two cases. Emissions are estimated by assuming average efficiencies for each plant type shown in Tables A3-A6. Emissions in the CEV are 30% below the Reference Case in 2020 and 81% below it in 2030. However, Long Island would be purchasing RECs to offset its fossil fuel generation in 2030, and it would be consistent with carbon accounting conventions to claim a carbon free electricity supply in 2030.

**Figure 4. Estimated Annual $CO_2$ Emissions from Long Island's Electricity in the Two Cases**




There would also be reductions in $NO_X$, $SO_2$, particulate matter and heavy metals, however these are more difficult to estimate. In addition, there would be significant economic development benefits and reduced exposure to higher fossil fuel prices, but estimating these benefits is beyond the scope of this work.

## E. Issues and Uncertainties

### *PV Additions*

The CEV includes 350 MW of ground-mounted PV capacity on the Island by 2030. This could be envisioned as: 10 large systems (assuming 35 MW per system) or 70 smaller systems (assuming 5 MW per project). Land availability and cost issues would pose a significant challenge to this scenario, and more work is needed to determine the feasibility of this scenario.

There would be roughly 330 commercial-scale systems on the Island by 2020 (assuming 300 kW per system) and 150,000 residential systems (assuming 3 kW per system). Regarding the residential systems, we estimate there were roughly 850,000 residential roofs in Nassau and Suffolk counties in 2010, based on census data. Using on this estimate, by 2030, we have developed roughly 18% of all the residential roofs existing today. Navigant Consulting estimates that, nationwide, roughly 22% of all residential roofs are suitable for PV, considering shading, orientation and other factors.[17] Using that figure, 187,000 of the residential roofs on the Island in 2010 are suitable for PV, and we have developed 80% of that figure by 2030. Of course, there will be more homes on the Island by 2030, and incorporating PV into new construction is easier than into existing homes. More work is needed to gauge the feasibility of the commercial projects envisioned here.

[17] Choudhari, et al., *PV Grid Connected Market Potential under a Cost Breakthrough Scenario*, Navigant Consulting, September 2004.

### *Distribution System Costs*

There has been much speculation in the industry about the distribution system cost impacts of adding large amounts of distributed generation (DG) to existing systems. DG can offer cost savings in the form of avoided costs on feeders with fast growing load, and it can also impose costs to upgrade equipment for more complex energy flows. Some distribution system upgrades are performed as part of routine maintenance, and on top of this, many U.S. utilities are collecting additional funds to implement “smart-grid” initiatives.

Assessing whether the level of PV penetration envisioned here would result in net distribution system costs or savings would require a detailed analysis of the Long Island system including the planned work that is already funded. This would be a useful analysis. In lieu of such a study we examined the impact of additional distribution system costs on our results and found that they affected net costs very little. We added $10 per MWh to all PV added between 2021 and 2030, a collection of 6.6 million per year by 2030 for distribution system upgrades. The addition of these costs did not change the percentage increase in supply costs (16%) or the average bill increase (8%) in 2030.

## F. Conclusions

The major conclusions of this work are as follows.

- It appears technically feasible for Long Island to have a 100% renewable and zero-carbon electricity supply by 2030, using many existing resources for capacity and using RECs to offset a modest amount of fossil generation.

- The incremental, annual power supply cost of the CEV in 2020 (relative to the Reference Case) would be in the range of 23% in 2020 and 16% in 2030.

- Average customer bills across all rate classes could be expected to increase by about 12% in 2020 and about 8% in 2030, relative to the Reference Case.

- The CEV would provide dramatic reductions in actual carbon emissions (in the range of 80% by 2030), and with the purchase of RECs, the Island would in effect be paying for a $CO_2$-free electricity supply.

- An aggressive move to renewable energy would provide benefits that have not been addressed here, including local economic development, reduced fuel price risk and reduced environmental and health impacts of power generation.

In addition, further work in the following areas would be useful.

- This CEV should be investigated with an hourly dispatch model. Important areas to explore are the accommodation of variable generation, the impact of expanding demand response markets, differences in the need for operating reserves and maintaining system stability.

- Energy efficiency is by far the lowest cost electricity resource at Long Island’s disposal, and many utilities are capturing more efficiency than LIPA is today. Several states are now funding efforts to capture "all cost effective" efficiency opportunities. The prospects for raising New York State's funding levels and efficiency goals should be explored.

## G. Data Appendix

**Table A1. Energy Requirements and Peak Loads in the Two Scenarios**

| | 2020 | 2030 |
|---|---|---|
| RC Energy Requirement (GWh) | 24,160 | 27,014 |
| CEV Energy Requirement (GWh) | 22,824 | 23,902 |
| RC Peak Load (MW) | 5,934 | 6,755 |
| CEV Peak Load (MW) | 5,625 | 6,033 |

**Table A2. Key Renewable Energy Cost Assumptions**

| | | Average Costs 2012–20 | | | Average Costs 2021–30 | | |
|---|---|---|---|---|---|---|---|
| Resource | Location | Installed Cost ($/kW) | Capacity Factor (%) | Levelized Cost without Subsidy ($/MWh) | Installed Cost ($/kW) | Capacity Factor (%) | Levelized Cost without Subsidy ($/MWh) |
| Onshore Wind | Off-Island | $1,950 | 35.0% | $90 | $1,950 | 36.0% | $88 |
| Offshore Wind | Off Island | $5,600 | 43.0% | $213 | $4,300 | 43.0% | $154 |
| Ground-mounted PV | On Island | $4,290* | 20.0%* | $243 | $2,795* | 22.0%* | $155 |
| Com. PV | On Island | $4,675* | 18.5%* | $325 | $3,065* | 18.5%* | $223 |
| Res. PV | On Island | $6,365* | 17.5%* | $352 | $3,840* | 17.5%* | $232 |
| Biomass | Off Island | $4,630 | 85% | $123 | $4,630 | 85% | $132 |
| Storage | On-Island | $1,170 | 32% | $89 | $1,008 | 32% | $82 |

*Costs shown for PV are in $\$/kW_{AC}$ and capacity factors are calculated using AC capacity and energy. Both costs and capacity factors are lower when stated in terms of $kW_{DC}$. We assume 80% efficiency in DC to AC conversion. The increase in capacity factor for ground-mounted PV systems in the second decade reflects our assumption that only a portion of projects are using tracking systems in the first decade while all new projects are using them in the second decade. Capacity factors were developed using the NREL's "PV Watts" tool.

| Table A3. | | | Reference Case 2020 | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Resource | Contract | Location | Nameplate Capacity (MW) | Capacity for LI LCR (MW) | 2012-20 Capacity Factor (%) | Energy (GWh) | Energy (%) | Cost ($/MWh) | Total Cost ($) |
| | | | | | | | | | |
| Nuclear | Energy+Cap. | Off-Island | 232 | 232 | 90.0% | 1,829 | 7.6% | $51 | $92,974,464 |
| Oil Steam | Energy+Cap. | On-Island | 361 | 361 | 12.0% | 379 | 1.6% | $368 | $139,700,764 |
| Refuse Steam | Energy+Cap. | On-Island | 120 | 120 | 50.0% | 526 | 2.2% | Not costed | Not costed |
| Gas Steam | Energy+Cap. | On-Island | 1900 | 1900 | 38.0% | 6,325 | 26.2% | $133 | $843,416,229 |
| Gas Steam | Capacity | Off-Island | 0 | 0 | 1.0% | 0 | 0.0% | $0 | $0 |
| Existing Diesel | Energy+Cap. | On-Island | 55 | 55 | 1.0% | 5 | 0.0% | $3,206 | $15,445,293 |
| Existing Oil CT | Energy+Cap. | On-Island | 685 | 685 | 1.0% | 60 | 0.2% | $1,222 | $73,301,515 |
| Existing Gas CT | Energy+Cap. | On-Island | 822 | 822 | 4.0% | 288 | 1.2% | $407 | $117,332,986 |
| Existing Gas CT | Capacity | Off-Island | 0 | 0 | 1.0% | 0 | 0.0% | $0 | $0 |
| New Gas CT | Energy+Cap. | On-Island | 0 | 0 | 16.0% | 0 | 0.0% | $0 | $0 |
| Existing CCCT | Energy+Cap. | On-Island | 695 | 695 | 67.0% | 4,079 | 16.9% | $103 | $418,687,889 |
| Existing CCCT | Capacity | Off-Island | 660 | 660 | 0.0% | 0 | 0.0% | $0 | $138,600,000 |
| Econ. Purch. | Energy | On/Off Island | 0 | 0 | 0.0% | 7,603 | 31.5% | $40 | $304,120,000 |
| New Gas CCCT | Energy+Cap. | On-Island | 0 | 0 | 82.0% | 0 | 0.0% | $0 | $0 |
| Storage | Capacity | On-Island | 0 | 0 | 0.0% | 0 | 0.0% | $0 | $0 |
| **Renewables** | | | | | | | | | |
| Large Wind | Energy | Off-Island | 200 | 0 | 35.0% | 613 | 2.5% | $90 | $55,188,000 |
| Large Wind | Energy+Cap. | Off-Island | 0 | 0 | 35.0% | 0 | 0.0% | $0 | $0 |
| Large Wind | Energy | Off-Island | 225 | 0 | 35.0% | 690 | 2.9% | $90 | $62,086,500 |
| Large Wind | Energy+Cap. | Off-Island | 0 | 0 | 35.0% | 0 | 0.0% | $0 | $0 |
| Offshore Wind | Energy+Cap. | Off-Island | 140 | 42 | 43.0% | 527 | 2.2% | $213 | $112,325,976 |
| Small Wind | Energy+Cap. | On-Island | 1 | 0 | 22.0% | 2 | 0.0% | $350 | $674,520 |
| Large PV | Energy+Cap. | On-Island | 50 | 22 | 20.0% | 88 | 0.4% | $243 | $21,286,800 |
| Com PV | Energy+Cap. | On-Island | 30 | 13 | 18.5% | 49 | 0.2% | $325 | $15,800,850 |
| Res PV | Energy+Cap. | On-Island | 100 | 44 | 17.5% | 153 | 0.6% | $352 | $53,961,600 |
| LFG | Energy | Off-Island | 10 | 0 | 25.0% | 22 | 0.1% | $60 | $1,314,000 |
| LFG | Energy+Cap. | Off-Island | 0 | 0 | 25.0% | 0 | 0.0% | $0 | $0 |
| Hydro | Energy | Off-Island | 25 | 0 | 33.0% | 72 | 0.3% | $50 | $3,613,500 |
| Hydro | Energy+Cap. | Off-Island | 0 | 0 | 33.0% | 0 | 0.0% | $0 | $0 |
| Biomass | Energy | Off-Island | 30 | 0 | 85.0% | 223 | 0.9% | $123 | $27,475,740 |
| Biomass | Energy+Cap. | Off-Island | 0 | 0 | 85.0% | 0 | 0.0% | $0 | $0 |
| Brookfield | Energy | Off-Island | 0 | 0 | N/A | 300 | 1.2% | | Not costed |
| PPL LFG | Energy | Off-Island | 0 | 0 | N/A | 25 | 0.1% | | Not costed |
| Bear Swamp | Energy+Cap. | Off-Island | 345 | 345 | N/A | 302 | 1.2% | | Not costed |
| | | | | | | | | | |
| Sums | | | 6,686 | 5,996 | | 24,160 | 100% | | $2,497,306,625 |

| Table A4. | | | Clean Electricity Vision 2020 | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Resource | Contract | Location | Nameplate Capacity | Capacity for LI LCR | 2012-20 Capacity Factor | Energy | Energy | Cost | Total Cost |
| | | | (MW) | (MW) | (%) | (GWh) | (%) | ($/MWh) | ($) |
| | | | | | | | | | |
| Nuclear | Energy+Cap. | Off-Island | 232 | 232 | 90.0% | 1,829 | 8.0% | $51 | $92,974,464 |
| Oil Steam | Energy+Cap. | On-Island | 187 | 187 | 8.0% | 131 | 0.6% | $459 | $60,211,846 |
| Refuse Steam | Energy+Cap. | On-Island | 120 | 120 | 50.0% | 526 | 2.3% | Not costed | Not costed |
| Gas Steam | Energy+Cap. | On-Island | 1700 | 1700 | 29.0% | 4,319 | 18.9% | $151 | $653,211,358 |
| Gas Steam | Capacity | Off-Island | 0 | 0 | 1.0% | 0 | 0.0% | $0 | $0 |
| Existing Diesel | Energy+Cap. | On-Island | 55 | 55 | 1.0% | 5 | 0.0% | $3,206 | $15,445,293 |
| Existing Oil CT | Energy+Cap. | On-Island | 874 | 874 | 0.9% | 54 | 0.2% | $1,305 | $70,286,546 |
| Existing Gas CT | Energy+Cap. | On-Island | 800 | 800 | 2.0% | 140 | 0.6% | $596 | $83,496,343 |
| Existing Gas CT | Capacity | Off-Island | 0 | 0 | 1.0% | 0 | 0.0% | $0 | $0 |
| New Gas CT | Energy+Cap. | On-Island | 0 | 0 | 14.0% | 0 | 0.0% | $0 | $0 |
| Existing CCCT | Energy+Cap. | On-Island | 695 | 695 | 55.0% | 3,349 | 14.7% | $113 | $378,054,834 |
| Existing CCCT | Capacity | Off-Island | 0 | 0 | 1.0% | 0 | 0.0% | $0 | $0 |
| Econ. Purch. | Energy | On/Off Island | 0 | 0 | 0.0% | 1,652 | 7.2% | $40 | $66,080,000 |
| New Gas CCCT | Energy+Cap. | On-Island | 0 | 0 | 82.0% | 0 | 0.0% | $0 | $0 |
| Storage | Capacity | On-Island | 150 | 150 | 32.0% | -42 | -0.2% | $89 | $37,422,720 |
| **Renewables** | | | | | | | | | |
| Large Wind | Energy | Off-Island | 735 | 0 | 35.0% | 2,254 | 9.9% | $90 | $202,815,900 |
| Large Wind | Energy+Cap. | Off-Island | 0 | 0 | 35.0% | 0 | 0.0% | $0 | $0 |
| Large Wind | Energy | Off-Island | 800 | 0 | 35.0% | 2,453 | 10.7% | $90 | $220,752,000 |
| Large Wind | Energy+Cap. | Off-Island | 0 | 0 | 35.0% | 0 | 0.0% | $0 | $0 |
| Offshore Wind | Energy+Cap. | Off-Island | 1000 | 300 | 43.0% | 3,767 | 16.5% | $213 | $802,328,400 |
| Small Wind | Energy+Cap. | On-Island | 2 | 0 | 22.0% | 3 | 0.0% | $350 | $1,011,780 |
| Large PV | Energy+Cap. | On-Island | 200 | 88 | 20.0% | 350 | 1.5% | $243 | $85,147,200 |
| Com PV | Energy+Cap. | On-Island | 60 | 26 | 18.5% | 97 | 0.4% | $325 | $31,601,700 |
| Res PV | Energy+Cap. | On-Island | 250 | 109 | 17.5% | 383 | 1.7% | $352 | $134,904,000 |
| LFG | Energy | Off-Island | 20 | 0 | 25.0% | 44 | 0.2% | $60 | $2,628,000 |
| LFG | Energy+Cap. | Off-Island | 0 | 0 | 25.0% | 0 | 0.0% | $0 | $0 |
| Hydro | Energy | Off-Island | 100 | 0 | 33.0% | 289 | 1.3% | $50 | $14,454,000 |
| Hydro | Energy+Cap. | Off-Island | 0 | 0 | 33.0% | 0 | 0.0% | $0 | $0 |
| Biomass | Energy | Off-Island | 80 | 0 | 85.0% | 596 | 2.6% | $123 | $73,268,640 |
| Biomass | Energy+Cap. | Off-Island | 0 | 0 | 85.0% | 0 | 0.0% | $0 | $0 |
| Brookfield | Energy | Off-Island | 0 | 0 | N/A | 300 | 1.3% | | Not costed |
| PPL LFG | Energy | Off-Island | 0 | 0 | N/A | 25 | 0.1% | | Not costed |
| Bear Swamp | Energy+Cap. | Off-Island | 345 | 345 | N/A | 302 | 1.3% | | Not costed |
| | | | | | | | | | |
| Sums | | | 8,405 | 5,681 | | 22,824 | 100% | | $3,026,095,026 |

| Table A5. | | | Reference Case 2030 | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Resource | Contract for | Location | Nameplate Capacity (MW) | Capacity for LI LCR (MW) | 2012-20 Capacity Factor (%) | 2021-30 Capacity Factor (%) | 2012-20 Energy (GWh) | 2021-30 Energy (GWh) | Energy (%) | 2012-20 Cost ($/MWh) | 2021-30 Cost ($/MWh) | Total Cost ($) |
| | | | | | | | | | | | | |
| Nuclear | Energy+Cap. | Off-Island | 232 | 232 | N/A | 90.0% | 0 | 1,829 | 6.8% | N/A | $51 | $92,974,464 |
| Oil Steam | Energy+Cap. | On-Island | 307 | 307 | N/A | 8.0% | 0 | 215 | 0.8% | N/A | $512 | $110,098,389 |
| Refuse Steam | Energy+Cap. | On-Island | 120 | 120 | N/A | 50.0% | 0 | 526 | 1.9% | N/A | Not costed | Not costed |
| Gas Steam | Energy+Cap. | On-Island | 1815 | 1815 | N/A | 38.0% | 0 | 6,042 | 22.4% | N/A | $162 | $980,740,111 |
| Gas Steam | Capacity | Off-Island | 0 | 0 | N/A | 1.0% | 0 | 0 | 0.0% | N/A | $0 | $0 |
| Existing IC | Energy+Cap. | On-Island | 55 | 55 | N/A | 1.0% | 0 | 5 | 0.0% | N/A | $3,274 | $15,773,310 |
| Existing Oil CT | Energy+Cap. | On-Island | 470 | 470 | N/A | 1.0% | 0 | 41 | 0.2% | N/A | $1,290 | $53,097,528 |
| Existing Gas CT | Energy+Cap. | On-Island | 820 | 820 | N/A | 3.0% | 0 | 215 | 0.8% | N/A | $507 | $109,343,409 |
| Existing Gas CT | Capacity | Off-Island | 0 | 0 | N/A | 1.0% | 0 | 0 | 0.0% | N/A | $0 | $0 |
| New Gas CT | Energy+Cap. | On-Island | 100 | 100 | N/A | 14.0% | 0 | 123 | 0.5% | N/A | $0 | $0 |
| Existing CCCT | Energy+Cap. | On-Island | 695 | 695 | N/A | 65.0% | 0 | 3,957 | 14.6% | N/A | $123 | $488,215,855 |
| Existing CCCT | Capacity | Off-Island | 500 | 500 | N/A | 0.0% | 0 | 0 | 0.0% | N/A | $0 | $105,000,000 |
| Econ. Purch. | Energy | On/Off Island | 0 | 0 | N/A | 0.0% | 0 | 1,995 | 7.4% | N/A | $40 | $79,800,000 |
| New Gas CCCT | Energy+Cap. | On-Island | 1100 | 1100 | N/A | 80.0% | 0 | 6,402 | 23.7% | N/A | $135 | $866,840,979 |
| Storage | Energy+Cap. | On-Island | 0 | 0 | N/A | 0.0% | 0 | 0 | 0.0% | N/A | $0 | $0 |
| **Renewables** | | | | | | | | | | | | |
| Large Wind | Energy | Off-Island | 300 | 0 | 35.0% | 36.0% | 613 | 315 | 3.4% | $90 | $88 | $82,939,680 |
| Large Wind | Energy+Cap. | Off-Island | 0 | 0 | 35.0% | 36.0% | 0 | 0 | 0.0% | $0 | $0 | $0 |
| Large Wind | Energy | Off-Island | 525 | 0 | 35.0% | 36.0% | 690 | 946 | 6.1% | $90 | $88 | $145,341,540 |
| Large Wind | Energy+Cap. | Off-Island | 0 | 0 | 35.0% | 36.0% | 0 | 0 | 0.0% | $0 | $0 | $0 |
| Offshore Wind | Energy+Cap. | Off-Island | 440 | 132 | 43.0% | 43.0% | 527 | 1,130 | 6.1% | $213 | $154 | $286,352,136 |
| Small Wind | Energy+Cap. | On-Island | 1 | 0 | 22.0% | 22.0% | 2 | 0 | 0.0% | $350 | $350 | $674,520 |
| Large PV | Energy+Cap. | On-Island | 100 | 44 | 20.0% | 22.0% | 88 | 96 | 0.7% | $243 | $155 | $36,222,600 |
| Com PV | Energy+Cap. | On-Island | 50 | 22 | 18.5% | 18.5% | 49 | 32 | 0.3% | $325 | $223 | $23,028,726 |
| Res PV | Energy+Cap. | On-Island | 150 | 66 | 17.5% | 17.5% | 153 | 77 | 0.9% | $352 | $232 | $71,744,400 |
| LFG | Energy | Off-Island | 10 | 0 | 25.0% | 25.0% | 22 | 0 | 0.1% | $60 | $60 | $1,314,000 |
| LFG | Energy+Cap. | Off-Island | 0 | 0 | 25.0% | 25.0% | 0 | 0 | 0.0% | $0 | $0 | $0 |
| Hydro | Energy | Off-Island | 25 | 0 | 33.0% | 33.0% | 72 | 0 | 0.3% | $50 | $50 | $3,613,500 |
| Hydro | Energy+Cap. | Off-Island | 0 | 0 | 33.0% | 33.0% | 0 | 0 | 0.0% | $0 | $0 | $0 |
| Biomass | Energy | Off-Island | 30 | 0 | 85.0% | 85.0% | 223 | 0 | 0.8% | $123 | $132 | $27,475,740 |
| Biomass | Energy+Cap. | Off-Island | 0 | 0 | 85.0% | 85.0% | 0 | 0 | 0.0% | $0 | $0 | $0 |
| Brookfield | Energy | Off-Island | 0 | 0 | N/A | N/A | 300 | 0 | 1.1% | | | Not costed |
| PPL LFG | Energy | Off-Island | 0 | 0 | N/A | N/A | 25 | 0 | 0.1% | | | Not costed |
| Bear Swamp | Energy+Cap. | Off-Island | 345 | 345 | N/A | N/A | 302 | 0 | 1.1% | | | Not costed |
| | | | | | | | | | | | | |
| Sums | | | 8,190 | 6,822 | | | | 27,013 | 100% | | | $3,580,590,888 |

| Table A6. | | | Clean Electricity Vision 2030 | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Resource | Contract for | Location | Nameplate Capacity (MW) | Capacity for LI LCR (MW) | 2012-20 Capacity Factor (%) | 2021-30 Capacity Factor (%) | 2012-20 Energy (GWh) | 2021-30 Energy (GWh) | Energy (%) | 2012-20 Cost ($/MWh) | 2021-30 Cost ($/MWh) | Total Cost ($) |
| Nuclear | Energy+Cap. | Off-Island | 232 | 232 | N/A | 90.0% | 0 | 1,829 | 7.7% | N/A | $51 | $92,974,464 |
| Oil Steam | Energy+Cap. | On-Island | 0 | 0 | N/A | 5.0% | 0 | 0 | 0.0% | N/A | $0 | $0 |
| Refuse Steam | Energy+Cap. | On-Island | 120 | 120 | N/A | 50.0% | 0 | 526 | 2.2% | N/A | | Not costed |
| Gas Steam | Energy+Cap. | On-Island | 1600 | 1600 | N/A | 10.4% | 0 | 1,458 | 6.1% | N/A | $315 | $459,741,804 |
| Gas Steam | Capacity | Off-Island | 0 | 0 | N/A | 1.0% | 0 | 0 | 0.0% | N/A | $0 | $0 |
| Existing IC | Energy+Cap. | On-Island | 0 | 0 | N/A | 1.0% | 0 | 0 | 0.0% | N/A | $0 | $0 |
| Existing Oil CT | Energy+Cap. | On-Island | 516 | 516 | N/A | 1.0% | 0 | 45 | 0.2% | N/A | $1,290 | $58,294,307 |
| Existing Gas CT | Energy+Cap. | On-Island | 768 | 768 | N/A | 3.0% | 0 | 202 | 0.8% | N/A | $507 | $102,409,437 |
| Existing Gas CT | Capacity | Off-Island | 0 | 0 | N/A | 1.0% | 0 | 0 | 0.0% | N/A | $0 | $0 |
| New Gas CT | Energy+Cap. | On-Island | 0 | 0 | N/A | 14.0% | 0 | 0 | 0.0% | N/A | $0 | $0 |
| Existing CCCT | Energy+Cap. | On-Island | 695 | 695 | N/A | 21.0% | 0 | 1,279 | 5.3% | N/A | $225 | $287,578,661 |
| Existing CCCT | Capacity | Off-Island | 0 | 0 | N/A | 1.0% | 0 | 0 | 0.0% | N/A | $0 | $0 |
| Econ. Purch. | Energy | On/Off Island | 0 | 0 | N/A | 0.0% | 0 | 867 | 3.6% | N/A | $40 | $34,680,000 |
| New Gas CCCT | Energy+Cap. | On-Island | 0 | 0 | N/A | 82.0% | 0 | 0 | 0.0% | N/A | $0 | $0 |
| Storage | Energy+Cap. | On-Island | 800 | 800 | N/A | 32.0% | 0 | -224 | -0.9% | N/A | $82 | $183,889,920 |
| **Renewables** | | | | | | | | | | | | |
| Large Wind | Energy | Off-Island | 905 | 0 | 35.0% | 36.0% | 2,254 | 536 | 11.7% | $90 | $88 | $249,993,756 |
| Large Wind | Energy+Cap. | Off-Island | 0 | 0 | 35.0% | 36.0% | 0 | 0 | 0.0% | $0 | $0 | $0 |
| Large Wind | Energy | Off-Island | 1000 | 0 | 35.0% | 36.0% | 2,453 | 631 | 12.9% | $90 | $88 | $276,255,360 |
| Large Wind | Energy+Cap. | Off-Island | 0 | 0 | 35.0% | 36.0% | 0 | 0 | 0.0% | $0 | $0 | $0 |
| Offshore Wind | Energy+Cap. | Off-Island | 2250 | 675 | 43.0% | 43.0% | 3,767 | 4,709 | 35.5% | $213 | $154 | $1,527,437,400 |
| Small Wind | Energy+Cap. | On-Island | 3 | 0 | 22.0% | 22.0% | 3 | 2 | 0.0% | $350 | $350 | $1,686,300 |
| Large PV | Energy+Cap. | On-Island | 350 | 133 | 20.0% | 22.0% | 350 | 289 | 2.7% | $243 | $165 | $132,845,400 |
| Com PV | Energy+Cap. | On-Island | 100 | 38 | 18.5% | 18.5% | 97 | 65 | 0.7% | $325 | $233 | $46,705,692 |
| Res PV | Energy+Cap. | On-Island | 450 | 171 | 17.5% | 17.5% | 383 | 307 | 2.9% | $352 | $242 | $209,101,200 |
| LFG | Energy | Off-Island | 20 | 0 | 25.0% | 25.0% | 44 | 0 | 0.2% | $60 | $60 | $2,628,000 |
| LFG | Energy+Cap. | Off-Island | 0 | 0 | 25.0% | 25.0% | 0 | 0 | 0.0% | $0 | $0 | $0 |
| Hydro | Energy | Off-Island | 100 | 0 | 33.0% | 33.0% | 289 | 0 | 1.2% | $50 | $50 | $14,454,000 |
| Hydro | Energy+Cap. | Off-Island | 0 | 0 | 33.0% | 33.0% | 0 | 0 | 0.0% | $0 | $0 | $0 |
| Biomass | Energy | Off-Island | 150 | 0 | 85.0% | 85.0% | 596 | 521 | 4.7% | $123 | $132 | $142,069,680 |
| Biomass | Energy+Cap. | Off-Island | 0 | 0 | 85.0% | 85.0% | 0 | 0 | 0.0% | $0 | $0 | $0 |
| Brookfield | Energy | Off-Island | 0 | 0 | N/A | N/A | 0 | 300 | 1.3% | | | Not costed |
| PPL LFG | Energy | Off-Island | 0 | 0 | N/A | N/A | 0 | 25 | 0.1% | | | Not costed |
| Bear Swamp | Energy+Cap. | Off-Island | 345 | 345 | N/A | N/A | 0 | 302 | 1.3% | | | Not costed |
| Sums | | | 10,404 | 6,093 | | | | 23,902 | 100% | | | $3,822,745,381 |