

Rate Impact on LIPA Resident and Commercial Customers Of 250MW Offshore Wind Development on Eastern Long Island

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Abstract

The Long Island Power Authority faces considerable challenges in supplying reliable electric energy to the island as a whole but most specifically to the eastern most end where growth in demand, particularly peak demand is most strong. Offshore wind is being considered as one of the means of providing needed energy and capacity to the east end. This paper provides policymakers a detailed analysis of the consumer cost impact of the development of a 250MW offshore wind project delivering energy on the eastern end of the island for a single year, 2019. The paper utilized the state-of-of-the-art software system, pCloudAnalytics™ to evaluate the benefits of wholesale energy and capacity market price suppression effects resulting from the installation of offshore wind. Given international experience with offshore wind installation, the benefits and costs of the offshore wind are compared with the status quo of energy delivery to residential and commercial customers in LIPA. That comparison indicates that a 250MW project would cause essentially no impact on cost per kWh (an inconsequential increase of 0.5% residential and 0.6% commercial). The results do not account for positive financial benefits from reduced transmission costs or for the environmental benefits in reduction in emissions, for the long-term benefits that would accrue from improved reliability, for reduction in transmission investment costs or for reduction in environmental air emissions.

1. OBJECTIVE OF THE PAPER

The objective of this paper is to provide policy and decision makers with a context for evaluating the development and deployment of offshore wind off the coast of Long Island. The study quantifies the benefits and costs of the development of a hypothetical 250MW offshore wind installation off the eastern end of Long Island relative to the retail cost of electricity delivered to residential and commercial consumers on Long Island. The paper provides a detailed analysis of the benefits of electric energy price suppression effects, i.e., the reduction in delivered electricity costs in Zone K of the New York ISO that result from generation that includes offshore wind relative to generation without offshore wind and predominantly fossil and nuclear sources. A second benefit captured is the credit for added capacity provided by the offshore wind. The capital costs of the offshore wind development have been estimated based on international experience.

The objective is to report the net of the benefits and the costs in terms of the bill impact on residential and commercial consumers on the island. Because our objective is to measure the

¹ Tabors Caramanis Rudkevich. The authors thank and acknowledge the thoughtful and helpful comments of the independent reviewers.

benefits within LIPA, we acknowledge, but do not present in detail, the price suppression effects that occur throughout the New York grid.²

2. BACKGROUND

Growth in electrical demand on Long Island is most rapid on the eastern end as identified in Utility 2.0: Long Range Plan developed by PSEG for LIPA.³ Figure 1 provides a vivid picture of the challenge in growth rate. It also shows the current challenge (horizontal line) caused by the currently limited transfer capability to the eastern end of Long Island. PSEG LI is planning on increased transmission to the eastern end with the South Fork Infrastructure project estimated to cost \$97 million in 2017 and an additional \$197 million to 2022.⁴ Figure 1 cannot reflect the zoning restrictions that limit the location of any major new fossil generation stations that could serve the incremental local load.

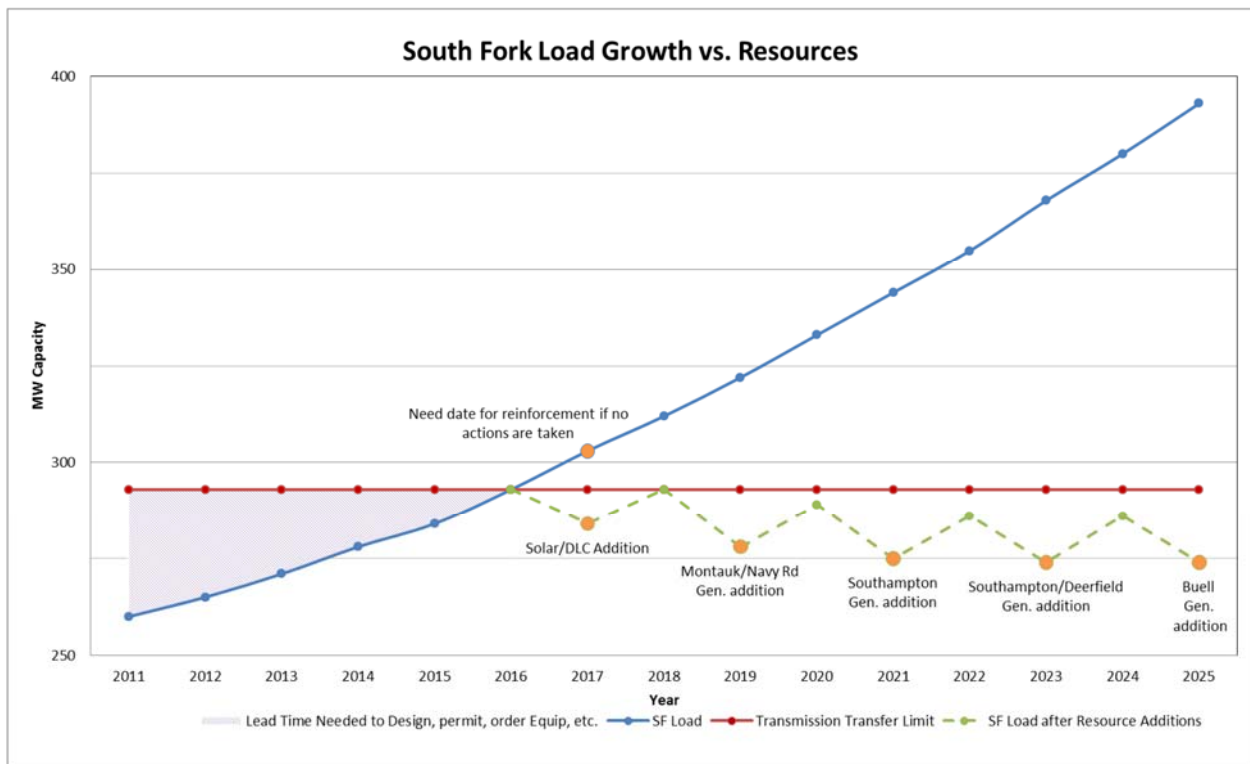


Figure 1 Utility 2.0 Projected Need for New Capacity to Serve Long Island’s East End

Utility 2.0 presents a scenario in which in 2019 two gas turbine generation units will be installed for a total of 25 additional megawatts.⁵ Utility 2.0 has documented a set of strategies for

² For an analysis of the geographic impact of price suppression effects see: Tabors, Omondi, Rudkevich, Goldis Amoak0-Gyan “Price Suppression and Emissions Reductions with Offshore Wind: An Analysis of the Impact of Increased Capacity in New England” Hawaiian International Conference on System Studies, 48. January 2015 (forthcoming).

³ Utility 2.0: Long Range Plan. Prepared for Long Island Power Authority by PSEG June 1, 2014.

⁴ Utility 2.0 Long Range Plan Update Document. Prepared for Long Island Power Authority by PSEG October 6, 2014 p. 20

⁵ Utility 2.0: Long Range Plan. Prepared for Long Island Power Authority by PSEG June 1, 2014. p. 3-31.

significantly limiting the growth in peak demand on Long Island and specifically on the eastern end. These strategies have included a range of distributed and renewable technologies along with a major effort in demand response aimed at peak reduction.

Offshore wind offers an additional option for the east end of Long Island as it has the potential of providing a significant addition to both energy and capacity as well as offering a reverse flow on the transmission system thus reducing the severity of South Fork transmission deficit.

Offshore wind is a proven technology with over 6,500 MW in operation in Europe. Offshore wind developments have flourished in the United Kingdom, Germany and Denmark. As of January 2014, the European market is reported to have installed a total of 2,080 turbines for a cumulative capacity of 6,562 MW spread across 69 wind farms in eleven countries.⁶

Recent studies and planning exercises conducted by the New York Department of State (DOS)⁷ and the New York Energy Research and Development Authority (NYSERDA)⁸ have shown significant potential for offshore wind off the coast of Long Island based on the area's high energy costs, large electric loads, robust wind resources, and existing industrial capacity. The Bureau of Ocean Energy Management (BOEM) – the federal agency with authority over the leasing of offshore areas for renewable energy production – leased one area off the coast of Long Island for offshore wind development and has plans to lease another area in the coming year.^{9 10}

Opposition to offshore wind development in the U.S. has most often focused on the additional cost to construct offshore wind turbines (over onshore wind and gas fired generation). Proponents, on the other hand, argue that offshore wind's high capacity factor and ability to deliver energy to constrained geographies such as Long Island allows it to compare favorably to other renewable generation in those locations

The discussions of offshore wind both pro and con have focused on the cost to construct (\$/MW) and the required per kWh cost that is paid for the offshore wind generated power. The greatest experience in offshore wind development is in the UK and Scotland and in Denmark. The current levelized cost of energy from current technology offshore wind in the UK is £140/MWh (\$210/MWh). The UK stated goal is to reach £100/MWh (\$150/MWh) by 2020.¹¹ DONG of Denmark reports a current levelized cost of €160/MWh (\$210/MWh) in 2013 with a goal of €100/MWh

⁶ European Wind Energy Association (2014. January). The European offshore wind industry key trends and statistics 2013. EWEA Offshore statistics. Retrieved in May, 2014 from:

http://www.ewea.org/fileadmin/files/library/publications/statistics/European_offshore_statistics_2013.pdf

⁷ DOS (2013). *New York Department of State offshore Atlantic Ocean Study*. DOS. July 2013. Online. Available:

http://docs.dos.ny.gov/communitieswaterfronts/ocean_docs/NYSDOS_Offshore_Atlantic_Ocean_Study.pdf

⁸ NYSERDA (2013). *NYSERDA Offshore Wind Program Update – BOEM NYS Offshore Wind Task Force*. New York State Energy Research and Development Authority. September 26, 2013. Online. Available: <http://www.boem.gov/NYSERDA-Offshore-Wind-Program-Update/>

⁹ *Commercial Wind Lease for the Wind Energy Area Offshore Rhode Island and Massachusetts*. Bureau of Ocean Energy Management. Online.: <http://www.boem.gov/Commercial-Wind-Lease-Rhode-Island-and-Massachusetts/>

¹⁰ *New York Activities*. Bureau of Ocean Energy Management. Online: <http://www.boem.gov/Renewable-Energy-Program/State-Activities/New-York.aspx>

¹¹ Wind Cost Reduction Task Force. (2012, June). *Offshore Wind Cost Reduction Task Force Report*. UK Government. Retrieved in May, 2014, from https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/66776/5584-offshore-wind-cost-reduction-task-force-report.pdf

(\$130/MWh) in 2020.¹² These cost reductions are seen both in the UK and in Denmark as achievable though relatively ambitious. For a hypothetical 250 MW offshore wind farm serving Long Island in 2019, AWS Truepower estimates a levelized cost of \$169 / MWh.¹³

Offshore wind, like all renewable energy sources integrated in the power sector, will suppress the wholesale energy market cost by displacing the most expensive existing generators that are running when the wind is generating, which will result in savings for ratepayers on the supply component of the retail price of electricity. We specifically analyze offshore wind because the benefits are significant and have only rarely been measured or presented in the regulatory debate which has focused more often on the cost of capital or the magnitude of power purchase agreements with incumbent utilities.¹⁴

In this paper we have explicitly looked to evaluate the benefits and costs of a major offshore wind installation on the retail costs to residential and commercial customers on Long Island where offshore wind represents a significant resource, where demand for new generation is acute and where there is a demonstrated interest and probable need for solutions that do not involve the addition large scale fossil generation resources.

As indicated, the analysis looks at LIPA within the NY ISO for the year 2019 and compares the system costs with and without the hypothetical 250 MW of offshore wind capacity. The model analyses are based on the structure of the New York ISO markets for energy and capacity and on LIPA's participation in those markets. As a result, the analyses assume that:

- LIPA buys all of its energy and capacity requirements from these wholesale markets at nodal LMP at its load busses.
- LIPA sells all of the energy and capacity that it either owns or controls through PPAs, into the NY ISO wholesale market, and as a result receives a credit at nodal LMP at the generation busses.
- The credit LIPA receives from energy and capacity it controls through its existing PPAs is expected, over time, to equal the value of that energy and capacity in the New York wholesale (LMP) market.
- In 2013 LIPA received credit for the energy and capacity from its interest in Nine Mile Point.
- In the 2019 Base Case LIPA receives credit for the capacity and for the energy from its interest in Nine Mile Point and new peaking generation installed on the east end of Long Island.
- In the 2019 Offshore Wind Case LIPA receives credit for the energy and capacity from its interest in Nine Mile Point, the new peaking generation and the hypothetical 250MW of offshore wind.

¹² Bakewell, S. (2013, January). Dong Targets 40% Cut in Wind Costs to Compete With Gas-Fed Power. Bloomberg News. Retrieved May 1, 2014, from <http://www.bloomberg.com/news/2013-03-01/dong-targets-40-cut-in-wind-costs-to-compete-with-gas-fed-power.html>

¹³ See Appendix D AWS Truepower memorandum on Capital Costs November 19, 2014.

¹⁴ It should be noted that the regulatory discussion finally approving the power purchase agreement by National Grid of 18.7 cents per kWh for the energy delivered from the Cape Wind project provided the evidence of the significance of price suppression with offshore wind development on the New England market. See Charles River Associates, Analysis of the Impact of Cape Wind on New England Energy Prices, February 8, 2010 prepared for Cape Wind Associates, LLC. <http://www.crai.com/uploadedFiles/Publications/analysis-of-the-impact-of-cape-wind-on-new-england-energy-prices.pdf?n=944>

3. ANALYTIC METHODOLOGY: IN BRIEF

A complete discussion of the models and data used in this analysis is provided in appendixes A through D. The analytic engine for the evaluation of the energy price suppression impacts of the addition of offshore wind was undertaken utilizing the Newton Energy Group (NEG) developed cloud based modeling system, *pCloudAnalytics*^{TM15} (*pCA*). *pCA* is an electric power market analytics environment that is implemented in the Amazon and Windows Azure commercial clouds that is described in greater detail in Appendix A. The analytic engine of *pCA* is Power System Optimizer (PSO) that provides chronological simulations of security constrained unit commitment, security constrained economic dispatch, and provision of ancillary services.¹⁶ The PSO engine accurately captures the full topology of the transmission network, accounts for contingency events and models operational constraints of generating units and demand response resources. PSO is based on the same mathematical logic and technology used by the market engines of MISO, PJM and ISO NE.

As implement here, we have been able, using *pCloudAnalytics*TM to calculate and report hourly Locational Marginal Prices for each of the load areas and generator nodes (generators less than 200MW are aggregated in the analysis) in New York. The LMP values represent the marginal cost of the next unit of energy consumed or produced at that nodal point in the ISO NE grid. From the perspective of the generator, these values are what is paid on a generator bus by generator bus basis to suppliers of energy. From the perspective of consumers the LMP represents the wholesale, load bus by load bus price of energy in New York. Knowing the hourly LMP at each bus and the hourly quantity delivered to the bus it is possible to calculate the total, LMP-based, wholesale cost of energy supplied to load.

Appendix B primarily developed by NEG provides a detailed listing of the assumptions and data used in calculation of the energy price suppression effects using *pCloudAnalytics* software system.

Appendix C provides a detailed discussion of the price suppression in the capacity market caused by the implementation of the hypothetical offshore wind. As shown, the capacity model is based on the structure and rules of the New York ISO Capacity market.

Appendixes D and E, prepared for TCR by AWS Truepower, provide analytic results for offshore wind revenue requirements and capacity value respectively.

4. RESULTS

The study estimated the projected average rates and monthly bills of residential and commercial customers in 2019 reported in 2013 dollars for a Base Case and an Offshore Wind case. The Base Case was business as usual and assumed no development of offshore wind capacity. The Offshore Wind case calculated the benefits and costs of a hypothetical 250 MW offshore wind farm operating for the 2019 calendar year. The study estimated the rate impact of

¹⁵ <http://www.newton-energy.com/pcloudanalytics>

¹⁶ www.psopt.com

the addition of offshore wind capacity as the difference between the projected average rates and monthly bills under the two Cases.

To compare the without wind and with wind cases we developed projections of average rates and monthly bills under the two cases as follows:

- Determine the power supply and delivery service components of the average annual rates LIPA charged residential and commercial customers in 2013, the most recent calendar year for which statistics were available;
- Estimate the power supply component of the rates LIPA would charge residential and commercial customers in 2019 under the Base Case and the Offshore Wind Case;
- Estimate the delivery service component of the rates LIPA would charge residential and commercial customers in 2019 under the Base Case and the Offshore Wind Case;
- Calculate the total rates LIPA would charge residential and commercial customers in 2019, and the resulting average monthly bills, under the Base Case and the Offshore Wind Case;

In the first step, we determined the power supply and delivery service components of the average annual rates LIPA charged residential and commercial customers in 2013 using LIPA specific data.¹⁷ As indicated in Table 1. LIPA Average Rates and Bills for Residential and Commercial classes, 2013 (average revenue /kWh) the average annual revenue per kWh that LIPA recovers from its residential and its commercial customers consists of those two components.

Table 1. LIPA Average Rates and Bills for Residential and Commercial classes, 2013 (average revenue /kWh)

	Residential	Commercial
Total Average annual revenue per kWh	0.205	0.163
Average annual Power Supply component	0.088	0.088
Average annual delivery service components	0.117	0.076
Average monthly bills	\$163.49	\$1,164

LIPA collects the majority of its fuel and purchased power costs through the power supply component of its total rate.¹⁸ LIPA collects its distribution system costs, its remaining purchased power costs and the costs of its ownership interest in the Nine Mile Point nuclear unit through the delivery service components of its total rate.¹⁹ The specific delivery service components specified

¹⁷ _____. *Biennial Report for Years Ended December 31, 2012 and December 2013*, Long Island Power Authority, August 2014. Table 5-3.

<http://www.lipower.org/pdfs/company/investor/bireport12.pdf>

¹⁸ NorthStar Consulting Group, *Comprehensive Management and operations Audit of Long Island Power Authority..* September 13, 2013. Page 19-3.

¹⁹ *Ibid.* Page 19-7.

in LIPA's tariffs consist of service charges (\$/day), energy charges (\$/kWh) and demand charges (\$/kW)²⁰

We then projected the power supply component of the rates that LIPA would charge in 2019 to be \$74/MWh under the Base Case and \$75/MWh under the Offshore wind Case. The study used these projections based on our assumption that LIPA's actual costs of power supply in 2019 will be close to its cost of purchasing energy and capacity from the respective New York wholesale markets in 2019. The assumptions and methodology the study used to project wholesale prices of energy and capacity are described in Appendix B.

The quantities of energy and capacity LIPA would require in 2019 are drawn from NY ISO Gold Book projections.²¹ Its projected cost of annual purchases reflects a credit for the market value of energy and capacity from its ownership interest in Nine Mile Point. The projected power supply component of \$75/MWh under the Offshore Wind Case reflects the Base Case energy and capacity purchases that would be reduced by the quantity of energy and capacity LIPA would receive from the Offshore Wind as is discussed in detail in Appendix B. The amount LIPA would pay for purchased power in 2019 is the Base Case amount minus the market value of the quantity of energy and capacity LIPA would receive from the Offshore Wind units plus the annual revenue requirements of the Offshore Wind units. The estimated annual revenue requirement of the Offshore Wind capacity in 2019 at the offshore site in Long Island is \$178.1 million noting that this value is based on current best estimates and that the European experience has shown significant variation in both installed and projected capital costs.²² These calculations are presented in Table B-2.

²⁰ *Biennial Report for Years Ended December 31, 2012 and December 2013, Long Island Power Authority, August 2014.* Table 5-1.
<http://www.lipower.org/pdfs/company/investor/bireport12.pdf>

²¹ New York Independent System Operator, 2014 Load & Capacity Data "Gold Book": April 2014

²² See Appendix D, Table 4.

Table B-2 Market Value of LIPA Purchased Energy and Capacity, 2013 Actual and 2019 Projected

	Units	Actual		Projections for 2019			
		2013		Base Case	Offshore Wind Case		
				Absolute	Absolute	Change vs Base - Absolute	Change vs Base - %
Capacity requirement, sources and costs							
1	UCAP purchased in Zone K	MW	5,244	5,773	5,773		
2	UCAP credit for new peaker capacity			25	25		
3	UCAP credit for new offshore wind capacity			-	93		
4	UCAP annual price - Zone K	\$/ kW-year	\$ 58.35	\$ 81.62	\$ 71.66		
5	UCAP requirement - NYCA	MW	561	239	239		
6	UCAP annual price - NYCA	\$/ kW-year	\$ 33.64	\$ 25.86	\$ 24.54		
7 = (1+12+13) * 14 + (L5*16)	cost of capacity valued at UCAP annual prices	000 \$	\$ 324,887	\$ 475,340	\$ 411,101	\$ (64,239.14)	-14%
Energy supply requirements, sources and costs							
8	total annual wholesale energy supply requirement (including T&D losses)	MWh	21,345,713	22,850,000	22,850,000	0	0%
9	energy credit for generation from nuclear		1,954,492	1,954,492	1,954,492		
10	energy credit for generation from new peakers			24,866	23,696		
11	energy credit for generation from new offshore wind units				1,107,927		
12	NY ISO wholesale energy market annual price (\$/ MWh)	\$/MWh	\$ 70.17	\$ 58.55	\$ 57.15	\$ (1.40)	-2%
113 = (10-11-110-111) * 112	cost of energy valued at wholesale annual price	000 \$	\$ 1,360,711	\$ 1,221,900	\$ 1,129,423	\$ (92,477)	-8%
14	Cost of new offshore wind units (annual revenue requirement)	000 \$		0	178,100		
Total Capacity and energy supply cost for energy service to retail customers recovered in Power Supply Charge							
15 = 17+ 113+114	annual cost of purchased capacity plus energy	000 \$	\$ 1,685,598	\$ 1,697,240	\$ 1,718,624	21,383	1%
16	Annual retail energy service	Mwh	19,931,093	21,335,688	21,335,688		
17 = L15 / L16	average annual cost of purchased capacity and energy per MWh of retail sales of energy service	\$/MWh	\$ 84.6	\$ 79.5	\$ 80.6	1.0	1%
B. Cost of new peakers recovered in delivery charge							
18	annual revenue requirement of capacity from new peakers	000 \$		2500	2500		
19 = 118/ 116	annual revenue requirement per KWh for new peakers	\$/kWh		\$ 0.1	\$ 0.1		
C. Residential sector - average rates and bills							
21	Average revenue/ KWH for Power Supply Charge	\$/kWh	\$ 0.0878	\$ 0.0795	\$ 0.0806	\$ 0.0010	1.3%
22 = 2013 value + I20	Average revenue /kWh for delivery service	\$/kWh	\$ 0.1172	\$ 0.1173	\$ 0.1173	\$ -	0.0%
23 = I22 + I21	Total average revenue / kWh	\$/kWh	\$ 0.2050	\$ 0.1969	\$ 0.1979	\$ 0.0010	0.5%
24	Average monthly consumption per customer	kWh	798	798	798	0.0000	0.0%
25= I24 * I23	Average monthly bill per customer	\$	\$ 163.49	\$ 157.00	\$ 157.80	0.80	0.5%
D. Commercial sector - average rates and bills							
26	Average revenue/ KWH for Power Supply Charge	\$/kWh	0.0878	0.080	0.081	0	1.3%
27 = 2013 value + I20	Average revenue /kWh for delivery service	\$/kWh	0.0757	0.076	0.076	0	0.0%
28 = I26 + I27	Total average revenue / kWh	\$/kWh	0.1635	0.155	0.156	0	0.6%
29	Average monthly consumption per customer	kWh	7,121	7,121	7,121	0	0.0%
30= I29 * I28	Average monthly bill per customer	\$	1,164	1,105	1,113	7.14	0.6%

LIPA acquires its fuel and purchased power through an agreement with NGRID and a portfolio of contracts with various IPPs. The specific prices LIPA pays under each of those contracts are confidential. However, it is reasonable to assume that the average annual unit cost LIPA pays for its aggregate power supply is unlikely to be materially above the market price, because that is its alternative source of supply. Similarly, it is reasonable to assume that the average annual unit cost LIPA pays for its aggregate power supply is unlikely to be materially below the market price, because that is its suppliers' alternative source of revenues. The study validated its assumption that the power supply component of the rates LIPA would charge in 2019 would approximate its cost of purchasing energy and capacity from the New York wholesale markets using data for 2013. As indicated in Table 3, LIPA's average annual power supply charge in

2013 was \$ 1,749, 892.²³ The corresponding average annual power supply charge is \$0.88/kWh, equivalent to \$88/MWh. Our estimate of its power supply cost based upon purchasing its requirements from the wholesale energy and capacity markets is within 3% of that amount, i.e., \$85/MWh confirming our hypothesis and analytics that LIPA was paying the equivalent of the wholesale market price for energy and capacity even if the transactions were through PPAs. This estimate is both reasonable and conservative, since LIPA's actual costs are likely somewhat higher than the wholesale market because of hedging related costs.

Table 3 LIPA average annual power supply charge in 2013 - Actual versus wholesale market estimates (\$/kWh)

	Actual (\$000)	Wholesale Market Estimate (\$000)
Capacity	confidential	\$ 324,887
Energy	confidential	\$1,360,711
Total	\$ 1,749, 892	1,685,598
Total annual retail use (MWh)	19,931,093	19,931,093
Annual cost / MWh	\$ 88	\$ 84.6
Actual versus Estimate	104%	

In the third step we assumed that the delivery service component of the rates LIPA would charge residential and commercial customers in 2019 under each Case would be the amount it charged in 2013, adjusted for any major changes in revenue requirements that would cause it to increase that component. Our study identified the acquisition of 25MW of peaking capacity as a projected change in revenue requirements that would cause LIPA to increase the delivery service that component of its rates. The projected annual revenue requirement of the new peaking capacity in 2019 is estimated to be roughly \$2.5 million.²⁴ That incremental annual revenue requirement is common to both Cases, since our study assumes LIPA would acquire that capacity under either Case.

Based on the logic presented above we calculated the total rates LIPA would charge residential and commercial customers in 2019 from the power supply and delivery service components projected. We then calculated the average rates and monthly bills that would result from those

²³ *Biennial Report for Years Ended December 31, 2012 and December 2013, Long Island Power Authority, August 2014.* Table 5-4. <http://www.lipower.org/pdfs/company/investor/bireport12.pdf>

²⁴ Estimated (conservatively) from USEIA Capital Cost for Electricity Plants, April 12, 2013 Table 1 at \$1,000/KW.

rates based on an assumption that average monthly use per customer in 2019 would be the same as in 2013.²⁵ Those average rates and bills are presented in Table 4.

The impact of the addition of 250MW of offshore wind on the eastern end of Long Island could increase costs to residential consumers by an inconsequential one half of one percent and for commercial customers by only six tenths of one percent. In addition, as indicated earlier in this paper, we have chosen to quantify only the demonstrable benefits of the addition of wind in terms of energy price suppression and incremental capacity value. The lesser quantifiable values of improved reliability, savings in transmission capital costs and reduction in air emissions were not estimated. In addition, as indicated in the introduction the price suppression impacts will be felt throughout New York State but would not be captured by the ratepayers of LIPA and as a result were not included.

Table 4 Average Rates and Bills in 2019 under Base Case and Offshore Wind

	Actual	Estimates			
	2012	2019			
	Actual	Base Case	Offshore Wind Case	Impact of offshore wind relative to Base Case. Increase (Decrease)	
				Absolute	%
Residential Sector					
Average revenue/ KWh for Power Supply	\$ 0.088	\$ 0.080	\$ 0.081	\$ 0.001	1.3%
Average revenue /kWh for delivery service	\$ 0.117	\$ 0.117	\$ 0.117	\$ -	0.0%
Total \$ / kWh	\$ 0.205	\$ 0.197	\$ 0.198	\$ 0.001	0.5%
Average monthly consumption per customer (kWh)	798	798	798	0.00	0.0%
Average monthly bill per customer (\$/month)	\$ 163.49	\$ 156.91	\$ 157.71	\$ 0.80	0.5%
Commercial Sector					
Average revenue/ KWh for Power Supply	\$ 0.088	\$ 0.080	\$ 0.081	\$ 0.001	1.3%
Average revenue /kWh for delivery service	\$ 0.076	\$ 0.076	\$ 0.076	\$ -	0.0%
Total \$ / kWh	\$ 0.163	\$ 0.155	\$ 0.156	\$ 0.001	0.6%
Average monthly consumption per customer (kWh)	7121	7121	7121	0	0.0%
Average monthly bill per customer (\$/month)	\$ 1,164.21	\$ 1,105.48	\$ 1,112.62	\$ 7.14	0.6%

²⁵ We note that the NY ISO forecasts a modest growth in demand of 0.5% that we have assumed as growth in customers and not in consumption per customer.

5. SUMMARY AND CONCLUSIONS

The objective of this study was to provide both policy makers and decision makers with a view of the costs and benefits of offshore wind technology as it could be developed off of the eastern end of Long Island. The import of the study is in showing that in a favorable location such as Long Island, using standard power system analytics, offshore wind is an attractive alternative. The wind regime in off of Long Island is superior to that on shore, the depth of water allows for cost effective construction and eastern Long Island is both deficit in energy and capacity and a difficult if not impossible zoning environment within which to construct conventional generating capacity. Offshore wind has the potential of providing an environmentally benign source of energy delivered where it is most needed.

The conclusion of the study is that, given current prices of natural gas, the current structure of the New York wholesale electric energy and capacity markets and experience in Europe in installation and operation of offshore wind that the hypothetical installation of 250MW would have essentially no impact on the average electricity rate of residential or commercial customers on Long Island.

It is important to note that our calculated benefit value of offshore wind is limited in scope and does not account for what is likely to be a reduction in the multiple hundred million transmission expansion plans of PSEG LI to service eastern Long Island, nor has it taken credit for the price suppression effects of the project in New York beyond Long Island. Both of these are likely to offer real and significant value for ratepayers in New York State.

APPENDIX A

pCloudAnalytics (pCA)²⁶

pCloudAnalytics utilizes the the Power System Optimizer Model (“PSO”) developed by Polaris Systems Optimizations, Inc. (“Polaris”) to perform the production cost modeling in the NYISO region. PSO is a detailed, MIP based, unit commitment and economic dispatch model that simulates the operation of the electric power system. PSO determines the security-constrained commitment and dispatch of each modeled generating unit, the loading of each element of the transmission system, and the locational marginal price (LMP) for each generator and load area. PSO support both hourly and sub hourly timescales. The analytical structure of PSO is graphically presented in Fig. A-1 which distinguishes four important components of PSO: Inputs, Models, Algorithms and Outputs. This document primarily focuses on data sources and analytical steps used by NEG to develop Inputs to the PSO. Where relevant, this document describes how PSO Models are configured to provide adequate representation of the NYISO market.

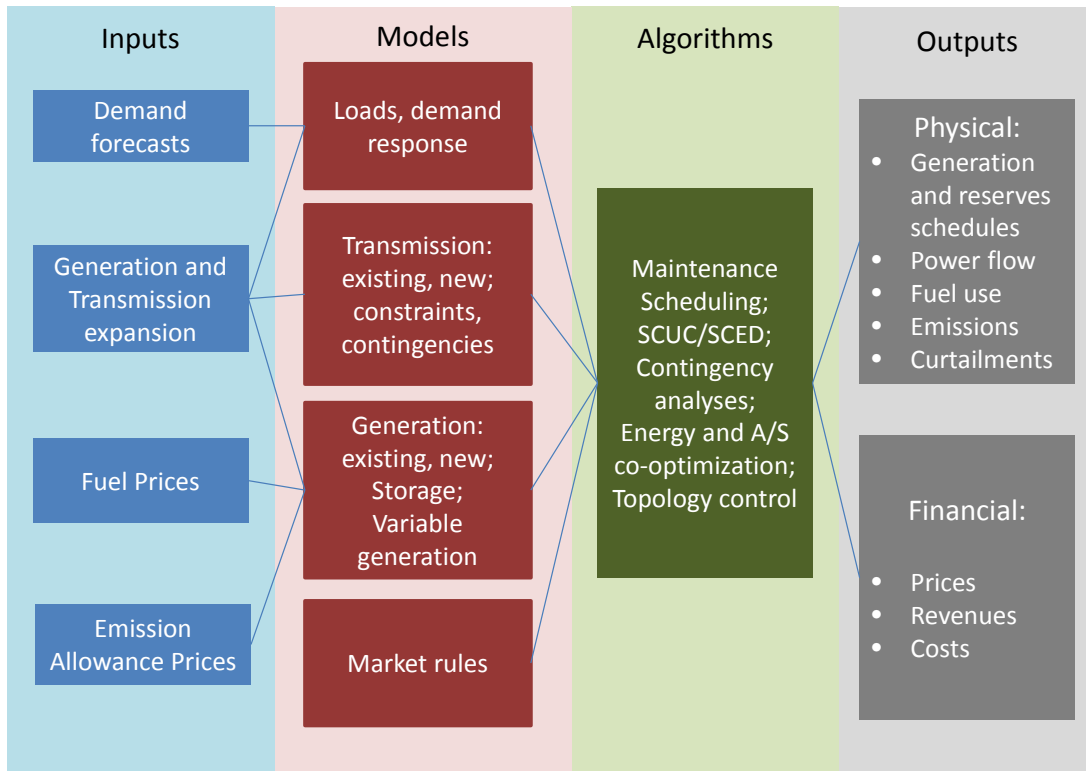


Figure A-1. Analytical Structure of PSO

NEG uses PSO as a power market simulator component of *pCloudAnalytics (pCA)* – a cloud based power market simulation environment implemented on Amazon EC2 commercial cloud. Fig. A-2 provides a

²⁶ pCloudAnalytics is the trademark software system of Newton Energy Group.

graphical representation of *pCA* architecture. *pCA* manages formation of data inputs for PSO organized into distinct simulation scenarios, partitions each scenario into concurrently simulated segments, provides virtual machines on the cloud to process segments through PSO, collects and reassembles simulations results into scenario specific outputs and loads them into the Explorable Energy Market Cube (E2MC). The user prepares input data and accesses modeling results in MS Excel. The user communicates with cloud resources through pLINC, a special software tool linking user's local environment with the cloud environment in Amazon EC2.

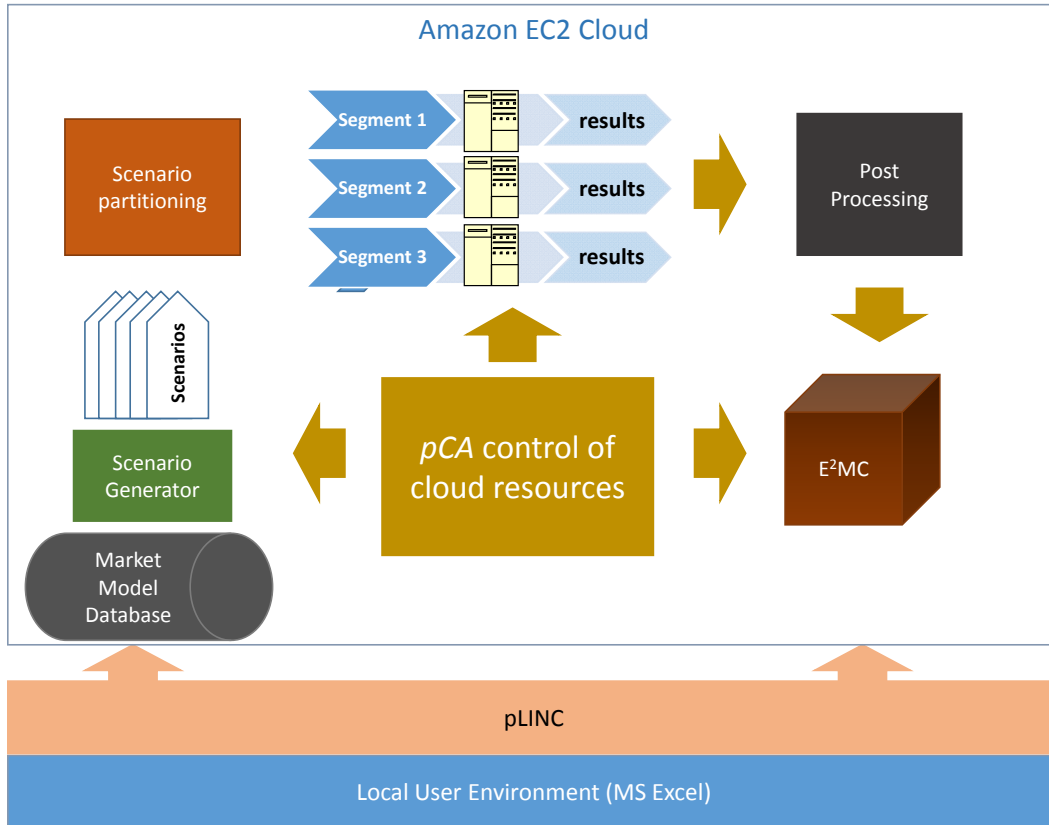


Figure A-2. Architecture of *pCloudAnalytics*

APPENDIX B

Assumptions and Data for Calculation of Energy Price Suppression Effects

Decision cycles

For the purpose of this project, the NYISO market is modeled through two decision cycles, the commitment (day-ahead) cycle and an hourly dispatch cycle. In the commitment cycle, generating units are turned on or kept on in order for the system to have enough generating capacity available to meet the expected peak load and required reserves in the system for the next day. PSO then uses the set of committed units to dispatch the system on an hourly basis, whereby committed units throughout the modeled footprint are operated between their minimum and maximum operating points to minimize total production costs. The unit commitment in PSO is formulated as a mixed integer linear programming optimization problem which is solved to the true optima using the commercial Gurobi solver.

The modeled geographic footprint in PSO for this project encompasses New York Control Area (NYCA) and power interchanges between NYCA and neighboring regions.

The key inputs for the PSO model, as used in the NYISO model, are summarized below. All financial inputs and resulting outputs are in December 31, 2013 real dollars.

Transmission

The physical location of all network resources is organized using substation and node mapping. The transmission topology is modeled based on 2013 FERC 715 powerflow fillings for summer peak 2015. NEG verified the power flow model against NYISO queue to make sure that essential projects are represented in the power flow case. Generators are mapped to bus bars/electrical nodes (eNodes). Bus bars are mapped to substations and substations are in turn mapped to NYISO Zones. In PSO, eNodes are modeled as children of bus bars and bus bars are synonymous with busses in the powerflow model. The mapping of bus bars to Zones allows PSO to allocate area load forecasts to load busses in proportion to the initial state from the powerflow. The use of both bus bars and eNodes allow users to distinguish between electrical and physical connections. This is useful in that it allows tracking of power-flow values of different injectors to the same bus. The powerflow model was solved to develop an initial state for injections and flows.

In determining a representative list of transmission constraints to monitor, NEG includes all major NYISO interfaces and critical contingencies. The set of contingencies to monitor and enforce was provided by PowerGEM based on the contingency analysis PowerGEM performed using their TARA tool. NEG developed limits for interfaces based on information provided in

NYISO planning studies²⁷ and on statistical analysis of NYISO historical data on interface limits actually enforced in the market in CY 2013. Table B-1 below shows the Interfaces limits applied

Interface	MaxMW	MinMW
DYSINGER-EAST	2700	-9999
WEST-CENTRAL	1425	-9999
VOLNEY-EAST *)	4600	-9999
MOSES-SOUTH	2475	-9999
CENTRAL-EAST	2900	-9999
TOTAL-EAST	5725	-9999
UPNY-SENY *)	5200	-9999
UPNY-CONED	4660	-9999
DNWDIE-SOUTH-PI	4485	-9999
Millwood South-c *)	8000	-9999

Table B-1: Interface limits.

*) These interfaces are not enforced by NYISO and were not enforced in the pCA analysis.

Load and Interchange Inputs

NYISO Load

PSO requires an hourly load shape for each simulated time frame and area modeled. For NYISO NEG constructs load shapes for each area from the following data:

- Template (historical) hourly load profiles
- Annual peak and energy forecast for the study period

As a template NEG used historical 2013 load profiles by NYISO zone. To develop hourly load forecast for 2019, NEG first calendar shifts the template load profile to align days of the week between the template year (2013) and the study period (2019), taking NERC holidays into account. NEG then uses the above data to modify hourly load profiles in such a manner that the resulting load shape exhibits the hourly pattern close to that of the template load profile while the total energy and peak demand in each zone match the energy and peak forecasts provided. Tables B-2 summarizes the annual peak and energy forecast by NYISO zone, as found in the 2014 Gold Book. NEG uses non-coincident summer peak as the annual peak demand by zone.

²⁷ “2013 Intermediate Area Transmission Review of the New York State Bulk Power Transmission System (Study Year 2018),” March 20, 2014

FORECAST OF ANNUAL ENERGY by ZONE (GWH)											
Year	A	B	C	D	E	F	G	H	I	J	K
2015	15,870	10,005	16,372	6,042	8,167	12,043	10,025	2,946	6,132	53,284	22,328
2016	15,942	10,025	16,441	6,072	8,214	12,128	10,062	2,953	6,146	53,402	22,522
2017	15,913	9,993	16,423	6,066	8,233	12,148	10,040	2,938	6,116	53,144	22,590
2018	15,925	9,988	16,447	6,075	8,277	12,201	10,038	2,931	6,105	53,046	22,720
2019	15,942	9,985	16,475	6,493	8,319	12,256	10,026	2,927	6,092	52,940	22,850
2020	16,012	10,009	16,553	6,721	8,395	12,334	10,042	2,927	6,096	52,969	23,043
2021	15,988	9,980	16,546	6,711	8,431	12,345	10,008	2,916	6,068	52,727	23,110
2022	15,998	9,979	16,583	6,717	8,480	12,391	9,999	2,910	6,056	52,622	23,240
2023	16,007	9,979	16,615	6,722	8,524	12,439	9,989	2,903	6,044	52,517	23,370
2024	16,060	10,009	16,696	6,744	8,608	12,525	10,004	2,905	6,049	52,556	23,565

FORECAST OF PEAK DEMAND by ZONE (MW)											
Year	A	B	C	D	E	F	G	H	I	J	K
2015	2,717	2,095	2,935	773	1,484	2,398	2,317	698	1,525	11,783	5,496
2016	2,731	2,103	2,955	775	1,500	2,429	2,337	692	1,511	12,050	5,543
2017	2,753	2,119	2,982	778	1,515	2,461	2,352	696	1,519	12,215	5,588
2018	2,777	2,135	3,012	781	1,535	2,500	2,364	696	1,524	12,385	5,629
2019	2,792	2,145	3,033	787	1,551	2,528	2,375	702	1,536	12,570	5,668
2020	2,800	2,152	3,050	861	1,565	2,554	2,383	710	1,552	12,700	5,708
2021	2,807	2,154	3,061	866	1,576	2,572	2,391	714	1,561	12,790	5,748
2022	2,813	2,157	3,074	870	1,590	2,596	2,398	718	1,573	12,900	5,789
2023	2,817	2,159	3,085	874	1,601	2,621	2,406	733	1,601	12,990	5,831
2024	2,821	2,163	3,096	878	1,613	2,650	2,412	739	1,613	13,100	5,879

Table B-2: Load Forecast summary by NYISO area.

For the purpose of this study, the model was set up to use historical 2013 load shapes synchronized with the wind generation profile for the hypothetical offshore wind unit developed by AWS TruePower and with historical 2013 interchange schedules between NYISO and neighboring systems.

Interchange Data

Interchange flows with external areas were taken from historical hourly data reported by NYISO for 2013. Similarly to load templates, interchange schedules were calendar shifted for the study period. Interchanges include connections between NYISO and external areas including Hydro Quebec (HQ), Ontario (IMO), New England (ISONE), and neighboring zones of PJM Interconnection (RECO, PSEG, PENELEC and JCPL). Since interchange data are provided on an aggregate basis and are not allocated to individual branches forming inter-system tie lines, the model included transmission representation of areas external to NYISO each assigned their loads and generators as specified in the power flow. In this set up, PSO scales external generators to balance the load in each external area subject to specified interchange schedules. This process provides a dynamic allocation of interchange flows between individual branches.

Disaggregated interchange schedules for DC lines such as Hudson Transmission Partners (HTP), Neptune (NEPT), Cross-Sound Cable (CSC) and for Linden Variable Frequency

Transformer (LIND VFT) were modeled as a combination of a generator and a load allowing simulations of bidirectional flows across these interchanges. These loads and generation were mapped to specific eNodes corresponding to points of physical interconnection in NYISO. These eNodes were assigned to distinct areas in NYISO. Table 3 displays the interchanges modeled.

Generation Additions and Retirements

Table B-3 below summarizes new addition assumptions per the 2014 Goldbook

Full Name	Type	Zone	In-service date	Capacity (MW)
Ball Hill Wind	Wind	A	1/1/2014	90
Marsh Hill Wind	Wind	C	10/1/2014	16.2
Dry Lots Wind	Wind	E	11/1/2014	33
Franklin Wind	Wind	C	12/1/2014	90
Cape Vincent	Wind	E	12/1/2014	209.3
Horse Creek Wind	Wind	E	12/1/2014	126
North Ridge Wind	Wind	E	12/1/2014	100
South Mountain Wind	Wind	E	12/1/2014	18
St. Lawrence Wind Farm	Wind	E	12/1/2014	75.9
Watkins	Wind	C	7/1/2015	122.4
Monroe County Mill Seat	Biomass	B	9/1/2015	3.2
Allegany NY Wind	Wind	A	11/1/2015	72.5
Franklin Wind	Wind	E	12/1/2015	50.4
Hounsfield Wind	Wind	E	12/1/2015	244.8
Monticello Hills Wind	Wind	E	12/1/2015	18
Roaring Brook Wind	Wind	E	12/1/2015	78
Taylor Biomass	Biomass	G	12/1/2015	19
CPV Valley	CCg100+	G	5/1/2016	677.6
Bowline #3	CCg100+	G	6/1/2016	775
Astoria Berrians I CC1	CCg100+	J	6/1/2016	250
Astoria Berrians I CC2	CCg100+	J	6/1/2016	250
South Pier Improvement	CCg100+	J	6/1/2016	88
Luyster	CCgo100+	J	6/1/2017	401
Cricket ES	CCg100+	G	1/1/2018	1019.9
PSEG Montauk I	GTg20	K	4/30/2018	10
PSEG II	GTg20	K	4/30/2018	15
Rolling Upland Wind	Wind	E	10/1/2018	59.9
LI Future GT1	GTg50	K	4/30/2019	50
Astoria Berrians II CC1	CCg100+	J	6/1/2019	250
Astoria Berrians II CC2	CCg100+	J	6/1/2019	250

Table B-3: New Additions in NYISO. Source: NEG Analysis

Table B-4 below summarizes assumed schedule of generator retirements in NYISO.

Unit	Zone	Type	Retire Date	Capacity
Station 9	B	GTg20	3/3/2014	14.3
Ravenswood 07	J	GTo50	3/13/2014	12.7
Selkirk-I	F	CCgo100+	9/1/2014	76.6
Selkirk-II	F	CCgo100+	9/1/2014	274.5
Dunkirk 2	A	STc250	6/1/2015	75
Astoria GT 05	J	GTo20	5/31/2016	13.2
Astoria GT 07	J	GTo20	5/31/2016	12.3
Astoria GT 08	J	GTo20	5/31/2016	12.8
Astoria GT 10 (Active - 7/15/13)	J	GTo50	6/1/2017	17.2
Astoria GT 11 (Active - 7/15/13)	J	GTo50	6/1/2017	16.5
Astoria GT 12	J	GTo50	6/1/2017	15.7
Astoria GT 13	J	GTo50	6/1/2017	16.1
Cayuga 1	C	STc250	7/1/2017	151.6
Cayuga 2	C	STc250	7/1/2017	158.9
Astoria GT 2-1	J	GTo50	5/31/2019	34.2
Astoria GT 2-2	J	GTo50	5/31/2019	33.3
Astoria GT 2-3	J	GTo50	5/31/2019	34.2
Astoria GT 2-4	J	GTo50	5/31/2019	33.5
Astoria GT 3-1	J	GTo50	5/31/2019	33.3
Astoria GT 3-2	J	GTo50	5/31/2019	34
Astoria GT 3-3	J	GTo50	5/31/2019	33.2
Astoria GT 3-4	J	GTo50	5/31/2019	34.1
Astoria GT 4-1	J	GTo50	5/31/2019	33.8
Astoria GT 4-2	J	GTo50	5/31/2019	34.5
Astoria GT 4-3	J	GTo50	5/31/2019	33.2
Astoria GT 4-4	J	GTo50	5/31/2019	32.3

Table B-4: Assumed retirements in NYISO. Source: NEG Analysis

Thermal Unit Characteristics

Thermal generation characteristics are generally determined by unit type. These include: heat rate curve shape, non-fuel operation and maintenance costs, startup costs, forced and planned outage rates, minimum up and down times, and quick start, regulation and spinning reserve capabilities.

Capacity ratings were obtained primarily from the 2014 Goldbook using listed Summer and Winter Dependable Maximum Net Generating Capability (DMNC) of each unit. Generator outage

rates were obtained the North American Electric Reliability Corporation (NERC) Generating Availability Report. NEG developed full load heat rates and emission rates for each generating unit using historical heat rate, emission data and generation information by plant and unit obtained from SNL Energy. NEG developed other operational characteristics such as start-up costs, Variable O&M costs and heat rate curves by unit type using various sources of publicly available information.

Due to the large number of small generating units, NEG aggregates all units below 20 MWs by type, fuel and area into a smaller set of units. Full load heat rates for the aggregates are calculated as the average of the individual units and all other parameters are inherited from the unit type. Single block units are mapped to individual eNodes and buses in the power flow. Combined cycle plants and aggregated units are mapped to aggregate nodes (aNodes) representing multiple buses in the network model.

Heat rate curves are modeled as a function of full load heat rate (“FLHR”) by unit type. For example,

- GT: Single block at 100% capacity at 100% of FLHR.
- CC: 4 blocks: 50% capacity at 113% of FLHR, 67% capacity at 75% of FLHR, 83% capacity at 86% of FLHR, and 100% capacity at 100% of FLHR.
 - *As an example, for a 500 MW CC with a 7000 Btu/KWh FLHR, the minimum load block would be 250 MW at a heat rate of 7910, the 2nd step would be 85 MW at a heat rate of 5250, the 3rd step would be 80 MW at a heat rate of 6020, and the 4th step would be 85 MW at a heat rate of 7000.*
- Steam Coal for all MW: 4 blocks: 50% capacity at 106% of FLHR, 65% capacity at 90%, 95% capacity at 95% FLHR, and 100% capacity at 100% FLHR.
- Steam Gas for all MW: 4 blocks: 25% capacity at 118% of FLHR, 50% capacity at 90%, 80% capacity at 95% FLHR, and 100% capacity at 100% FLHR.

Table B-5 below shows other assumptions by type for thermal plants. The abbreviations in the Unit Type column are structured as follows: First 2-3 characters identify the technology type, the next 1-2 characters identify the fuel used (gas, oil, coal, refuse) and the numbers identify the size of generating units mapped to that type.

Unit Type	Min Up Time (h)	Min Down Time (h)	EFORd (%)	VOM (\$/MWh)	Startup Cost (\$/MW-start)	Startup Failure Rate
CCg100	6	8	4.35	2.5	35	0.01
GTb50 (1-19MW)	1	1	19.73	0	35	0.06
GTb50 (20-49MW)	1	1	10.56	0	35	0.03

GTg50 (1-19MW)	1	1	19.73	10	0	0.06
GTg50 (20-49MW)	1	1	10.56	10	0	0.03
GTg50+	1	1	7.25	10	0	0.02
ICr50 (0-50MW)	10	8	19.73	2	40	0.06
NUC-PWR (400-799MW)	164	164	2.58	0	35	0
NUC-BWR (400-799MW)	164	164	3.24	0	35	0.02
NUC-PWR (800-999MW)	164	164	4.34	0	35	0.01
NUC-BWR (800-999MW)	164	164	1.8	0	35	0.05
NUC-PWR (1000+MW)	164	164	2.88	0	35	0.004
NUC-BWR (1000+MW)	164	164	2.82	0	35	0.025
STc100 (0-100MW)	24	12	10.64	5	45	0.02
STc200 (100-199MW)	24	12	6.3	4	45	0.03
STc300 (200-299MW)	24	12	7.1	4	45	0.03
STc400 (300-399MW)	24	12	6.85	3	45	0.04
STc600 (400-599MW)	24	12	7.82	3	45	0.06
STc800 (600-799MW)	24	12	6.71	2	45	0.03
STc1000 (800-999MW)	24	12	4.65	2	45	0.04
STc1000+ (1000+MW)	24	12	8.62	2	45	0.06
STg100 (0-100MW)	10	8	12.55	6	40	0.009
STg200+ (100-200MW)	10	8	7.28	5	40	0.01
STgo300 (200-299MW)	10	8	6.67	4	40	0.02
STgo400 (300-399MW)	10	8	5.41	4	40	0.02
STgo500 (400-599MW)	10	8	9.06	4	40	0.03

STgo600 (600-799MW)	10	8	9.48	3	40	0.05
STgo600+	10	8	1.93	3	40	0.02
STo100 (1-99MW)	10	8	3.54	6	40	0.006
STo200 (0-200MW)	10	8	5.6	5	40	0.02
STo600 (200-299MW)	10	8	10.59	4	40	0.02
STo600 (300-399MW)	10	8	4.53	4	40	0.02
STo600 (400-599MW)	10	8	4.45	4	40	0.01
STo600+ (600-799MW)	10	8	41.26	3	40	0.03
STo600+ (800-999MW)	10	8	14.36	3	40	0.09
STr	10	8	10.26	2	40	0.02

Table B-5: Thermal Unit Assumptions by type and size. Source: NEG Analysis.

Nuclear Units

Nuclear plants are assumed to run when available, and have minimum up and down times of approximately one week (164 hours). Capacity ratings, planned outage rates and forced outage rates are the same as those obtained from the NERC Generating Availability Report. The values represent a normalized annual rate that does not directly capture the timing of refueling outages. In general, nuclear facilities are treated as must-run units. Production costs were modeled using NEG input assumptions for fuel and variable O&M. Nuclear units are displayed in Table B-6 with associated areas, summer capacity and winter capacity.

Name	Area	Summer Capacity (MW)	Winter Capacity (MW)
Fitzpatrick1	C	881.8	851.1
IndianPt2	H	1024.5	1031.3
IndianPt3	H	1044.2	1044.3
NineMilePt 1	C	637.1	636.4
NineMilePt 2	C	1287.2	1287.2
Ginna	B	581.5	582.1

Table B-6: Nuclear Units by area and capacity.

Hydro and Pumped Storage

Hydro units are specified as a daily pattern of water flow, i.e. the minimum and maximum generating capability and the total energy for each plant. Of those, NEG assumed that hydro plants use 40% of the daily energy at the same level in each hour of the day. The remaining 60% of the daily energy is optimally scheduled by PSO to minimize system-wide production costs. Daily energy was estimated using plant specific capacity factors under the assumption that hydro conditions do not vary significantly across seasons. PSO fully optimizes pumped storage operation schedules.

Renewable Energy Resource

In this project, NEG modeled Wind generating capacity. Wind technology has an hourly generation profile developed using the 10 minute wind power output profiles- averaged hourly-obtained from the National Renewable Energy Laboratory (NREL)²⁸. Wind Sites in NYISO were mapped to the nearest NREL wind site to obtain the hourly schedule for that wind site. The resulting schedule was scaled to the capacity of the NYISO wind site and then date shifted to the desired year which is to be modeled. For the hypothetical offshore wind unit, hourly power output profiles synchronized with 2013 load shapes were provided by AWS Truepower.

Operating Reserves

Following NYISO's structure of ancillary services, NEG modeled 3 types of reserves: 10 minute spinning (10MSR), 10 minute non-spinning (10MNSR) and 30 minute reserves (30MR). Reserves are cascading, excess higher quality reserves count toward meeting lower quality reserve requirements. Spinning reserves are based upon NERC requirements and NYISO has locational requirements for the reserves on Long Island and near Central East. NEG assumes that hydro can provide spinning reserves for up to 50% of its available dispatch range. Non-spinning reserves can be provided by GTs and Internal Combustion (IC) units. Nuclear and renewables provide no reserves.

Table B-7 below summarizes reserve requirements in NYISO. SR is Spinning Reserve, 10MR is 10-Minute Reserve, and 30MR is 30-Minute Reserve. Reserves are cascading; excess 10MSR counts toward 10MNSR requirements and both excess 10MSR and 10MNSR reserves count toward 30MR.

²⁸ National Renewable Energy Laboratory (US), "Wind Systems Integration - Eastern Wind Integration and Transmission Study," nrel.gov, 2010. [Online]. Available: <http://www.nrel.gov/wind/systemsintegration/ewits.html>

Reserve Type	Area	Requirement (MW)
10MSR	NYISO	665
10MNSR	NYISO	665
30MR	NYISO	665
10MSR	ENY (Zones F-K)	330
10MNSR	ENY	870
10MNSR	K	120
30MR	K	150 Off-peak /420 On-peak

Table B-7: Reserve requirements. Source: NYISO Locational Reserve Requirements²⁹

Emission Rates

Emission rates for NO_x and SO₂ were obtained from historical SNL emission rate data. For plants for which there were no emission rates generic EIA emission data were used. CO₂ emission rates by fuel type were taken from EPA’s “Fuel and Carbon Dioxide Emissions Savings Calculation Methodology for Combined Heat and Power Systems” document: http://www.epa.gov/chp/documents/fuel_and_co2_savings.pdf

Emission Allowance Prices

NEG used NYISO’s forecast of emission allowance prices per 2013 Congestion Assessment and Resource Integration Study as presented in Table B-8.

	2014	2015	2016	2017	2018	2019	2020	2021	2022
NO _x	80.97	85.51	89.91	91.23	94.36	96.99	98.94	103.02	108.28
SO _x	3.38	3.56	1,252.88	1,324.10	1,392.07	1,457.38	1,519.72	1,579.06	1,635.55
CO ₂	3.91	5.56	7.35	9.10	9.30	9.44	12.21	12.70	13.29

Table B-8: Emission Allowance Prices Forecast ((in \$2013 per ton). Source: NYISO³⁰

Fuel Prices

NEG constructed a natural gas fuel forecast at Henry Hub from EIA-2014 energy outlook and forward curves as of November 1, 2014 for Henry Hub and major pipeline pricing points obtained from SNL Energy. NEG’s compiled projection of annual natural gas prices at Henry Hub is shown in Fig. B-1.

²⁹ http://www.nyiso.com/public/webdocs/markets_operations/market_data/reports_info/nyiso_locational_reserve_reqmts.pdf

³⁰ NYISO, “2013 Congestion Assessment and Resource Integration Study. CARIS – Phase 1.” November 19, 2013

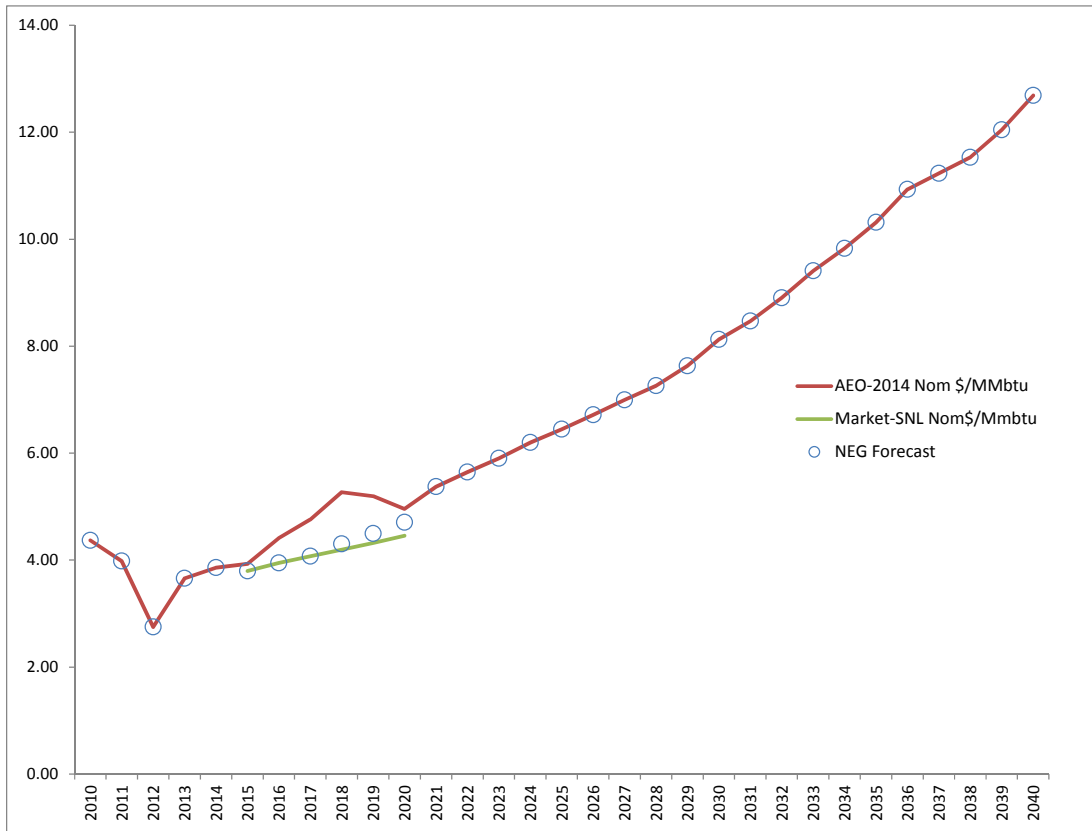


Figure B-1: Projection of Natural Gas Prices at Henry Hub

To develop monthly projections of natural gas prices at major pipeline points, NEG combined the compiled Henry Hub projection with pipeline specific basis differentials derived from SNL Energy’s forward curves. Resulting monthly natural gas price for 2019 expressed in 2013 real dollars per MMBtu are presented in Table B-9.

	Henry Hub	Iroquois Zone 1	Iroquois Zone 2	Niagara	Iroquois Waddington	Transco Zone 6 NY
Jan-19	4.18	9.89	10.97	3.84	9.83	10.25
Feb-19	4.15	8.97	9.31	3.82	8.91	9.08
Mar-19	4.09	5.25	5.57	3.76	5.18	4.57
Apr-19	3.83	3.98	3.79	3.38	3.91	3.48
May-19	3.84	3.91	3.87	3.32	3.85	3.47
Jun-19	3.86	3.93	3.91	3.30	3.86	3.18
Jul-19	3.88	3.89	4.04	3.32	3.83	3.43
Aug-19	3.89	3.90	4.05	3.33	3.84	3.34
Sep-19	3.88	3.89	4.03	3.32	3.83	3.07
Oct-19	3.90	3.92	4.00	3.36	3.86	3.10
Nov-19	3.98	3.96	4.15	3.65	3.89	3.54
Dec-19	4.14	7.78	8.20	3.81	7.72	6.33

Table B-9: Monthly Natural Gas Prices by Major Hub serving NYISO (real 2013 \$/MMBtu)

NEG used the following approach to develop a projection of fuel oil prices. First, NEG compiled the crude oil price forecast using EIA’s long term projection from the Annual Energy Outlook and Futures prices for crude oil (as of November 1, 2013) as shown in Fig. B-2.

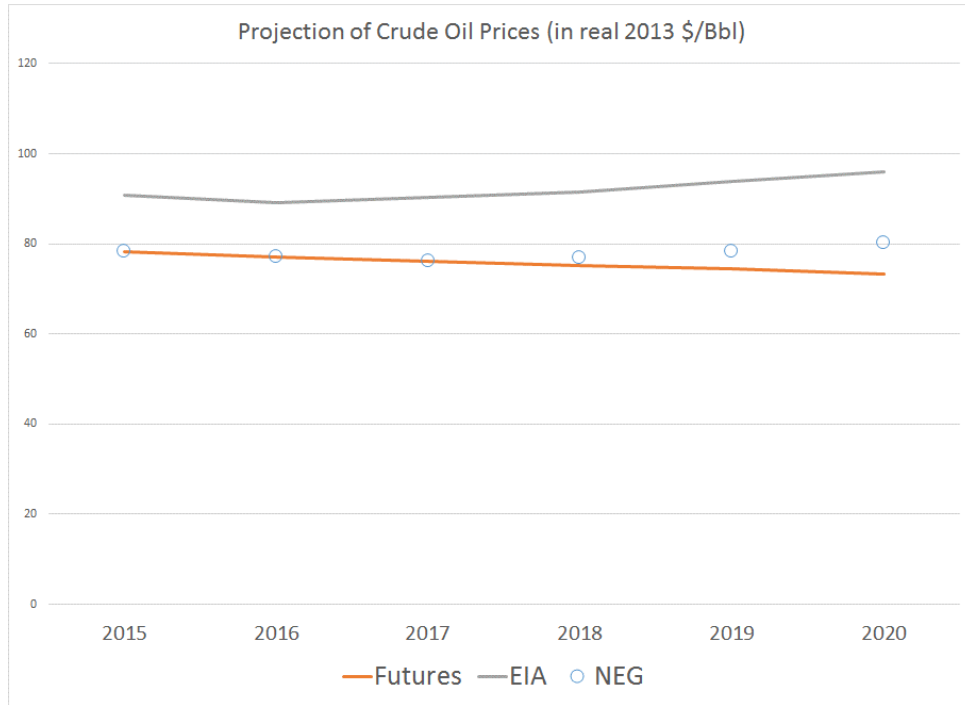


Figure B-2: Projection of Crude Oil Prices

Projections of No. 2 and No. 6 fuel oil prices are then formed using NEG’s developed regression models for these fuels to crude oil based on monthly historical statistics for the period from January 1, 2010 through July 2014. The resulting prices are presented in Table B-10.

	2015	2016	2017	2018	2019	2020
FO2 \$/MMBtu	17.07	16.83	16.61	16.76	17.07	17.48
FO6 \$/MMBtu	12.21	12.04	11.88	11.99	12.21	12.50

Table B-10: Projection of Fuel Oil Prices in NY (real 2013 \$/MMBtu)

NEG's assumes that coal prices will remain unchanged from historical levels in real terms. NEG obtained historical coal prices from SNL Energy's production cost curves, summarized in Table B-11 below. SNL/Delivered column provides coal prices as delivered to power plants.

Name	Area	Price (\$/MMBtu)
Cayuga	C	2.41
Danskammer*	G	2.26
Dunkirk	A	1.78
Fort Drum	E	2.23
Huntley	A	1.75
Jamestown	A	3.36
Somerset	A	2.62
Syracuse Energy	C	2.56

Table B-11: Coal prices by plant.

*Retired as of 1/3/2013

APPENDIX C

Assumptions and Data for Calculation of Capacity Price Suppression Effects

Installed Capacity (ICAP) requirements and associated prices in the New York system are established for four localities (ICAP zones): New York City (Zone J), Long Island (Zone K), combination of Zones G, H, I and J (“G-J Locality”) and for the entire New York Control Area (NYCA) combining all zones A through K. ICAP prices are established through balancing supply and local capacity requirements within each of these localities. Capacity price formation is subject to what can be called a “greater or” rule. Thus, if the capacity price applied to Zone J will be the maximum of capacity prices separately established for Zone J, G-J Locality and for NYCA. Similarly, capacity price in Zone K will be the greater between Zone K price and NYCA price while price in the G-J locality will be the maximum between price for that locality and NYCA price.

NYCA prices apply to load serving entities and generators located in the Rest of State (ROS) – a combination of zones A through F.

Generators in zones G through I receive G-J locality price, in Zone J - New York City capacity price and Long Island – Zone K capacity price.

All Load Serving Entities (LSEs) must procure capacity resources in excess of their coincident summer peak demand to meet NYCA reserve margin requirement, currently at 17%. LSEs serving loads in one of the localities such as New York City, Long Island and G-J Locality must meet certain part of these total capacity requirements by procuring capacity in these localities. For example, LSEs in Long Island should meet their capacity requirements by procuring 107% of Zone K non-coincident summer peak demand from resources electrically located in Long Island while the remaining portion of their capacity requirements may be purchased from elsewhere in NYCA

LSEs procure their installed capacity requirements through the auctions and bilaterally, under both long- and short-term contracts. Their capacity needs must be met separately for each of two seasons, or capability periods: The summer capability period, from May to October, and the winter capability period, from November through April. Installed capacity is first procured for all six months of each period through the strip auction. During the strip auction, capacity is procured for an entire capability period.

The strip auction is followed by subsequent monthly and spot auctions, which take place every month. During the monthly auction, capacity can be procured for each remaining month of the capability period. Finally, during the monthly spot auction, buyers can procure any remaining capacity needs for that month or sell excess capacity. In New York, as in some other markets, capacity requirements and supply are expressed in terms of “unforced capacity” (UCAP), a measure of installed capacity adjusted to account for generation outages. Prices in the Spot

Auction for each location are determined by the administratively set demand curves depicted in Figure below (the figure shows demand curves for Zone K and for NYCA and does not show the demand curve for New York City and for G-J locality that are not relevant for this study).

As this figure shows, the spot auction price depends on the level of UCAP available in that month. The level of UCAP is presented in relative terms with respect to the projected locational UCAP requirement. The demand curve for NYCA is determined in terms of UCAP requirements for the entire control area. When more capacity is added to the system at a relevant location, the capacity price for that location declines as shown in C-1. It is important to note that when capacity is added in Zone K – as is the case with the hypothetical offshore wind resource – it affects both the Zone K capacity balance and NYCA capacity balance and therefore impact both Zone K and NYCA capacity prices.

To assess the impact of the hypothetical offshore wind project on capacity prices in Zone K and in NYCA and associated Long Island’s ratepayer costs, we first developed a forecast of the demand curves for both Long Island and NYCA and then computed capacity prices under two scenarios: 1) without offshore wind and 2) with offshore wind. The potential savings in capacity costs in Long Island is the sum of two impact of components – savings due to reduction in Zone K capacity price and savings due to reduction in the NYCA capacity prices.

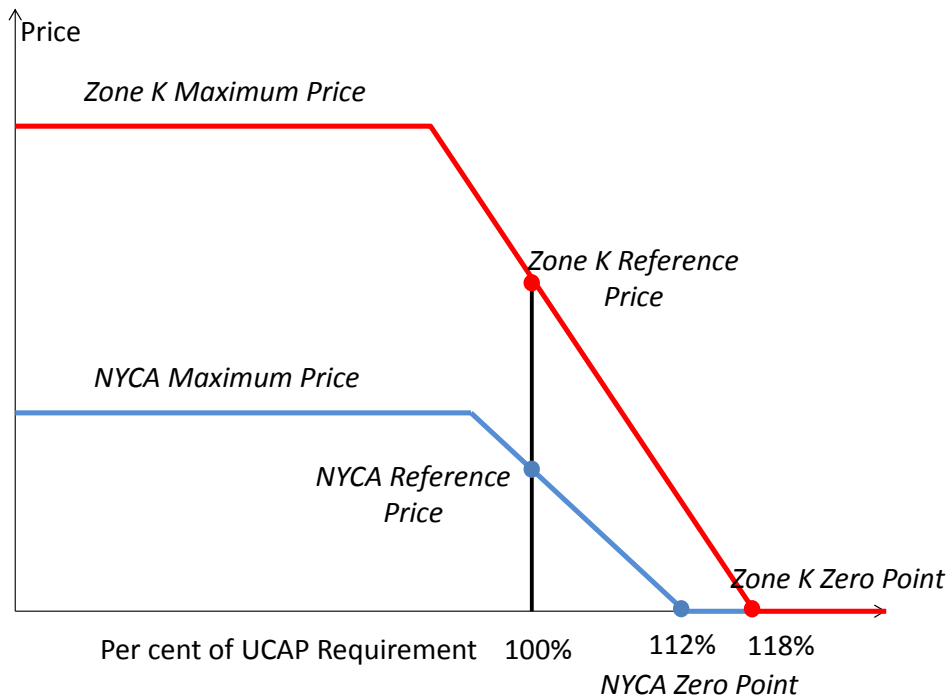


Figure C-1. Capacity spot price formation mechanism

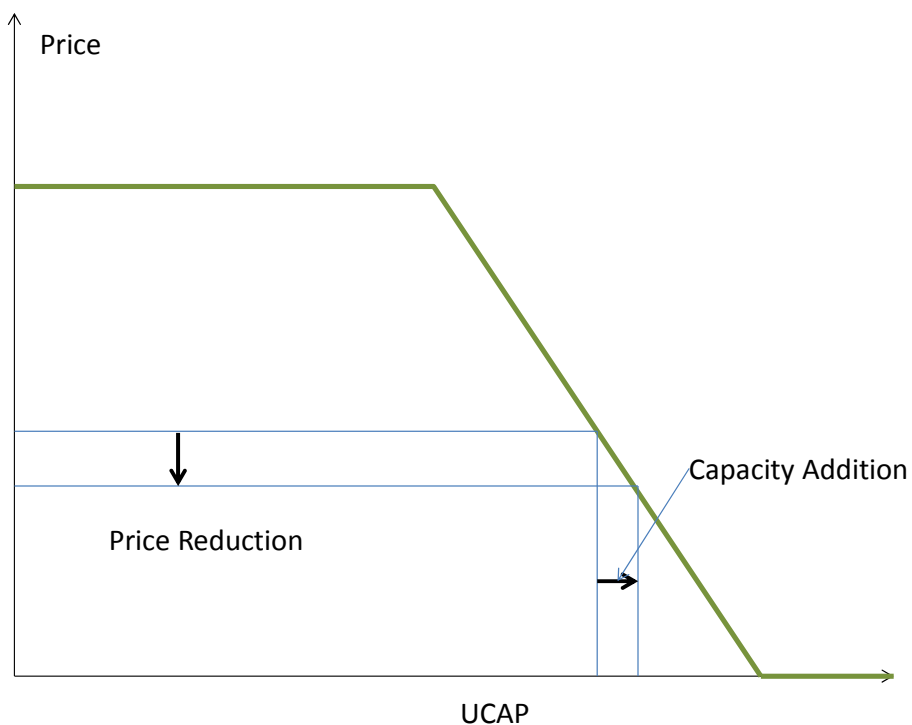


Figure C-2. Impact of capacity addition on capacity price.

The results of our analysis are presented in Table C-1. As shown in this Table, the major impact is attributable to price reductions in Zone K where addition of the offshore wind project reduces capacity prices by \$0.82-\$0.83 per kW-month. According to the NYISO ICAP manual, offshore wind contribution to UCAP is counted at 38% of installed capacity. Installed capacity of offshore wind is 245.7 MW and its contribution to UCAP equals to 93.37 MW.³¹ Zone K demand curve slope is $-\$0.819/\text{kW-month}$ for every 100 MW of additional UCAP in summer months and $-\$0.941/\text{kW-month}$ for every 100 MW of additional UCAP in winter months

The UCAP quantity LSEs in Zone K must procure at NYCA prices is relatively small. Furthermore, we project in 2019 a significant surplus of installed capacity in NYCA effectively driving winter capacity prices in NYCA to zero and resulting in no reduction in capacity price in the With Offshore Wind scenario in winter months. In the Without Offshore Wind case, summer capacity prices in NYCA are projected to be at $\$4.31/\text{kW-month}$. However, the magnitude of the

³¹ See Appendix D AWS Truepower memorandum on Capital Costs November 19, 2014.

slope of the NYCA demand curve is approximately four times smaller than in Zone K resulting in four times smaller impact of offshore wind on NYCA capacity prices.

Zone K UCAP Requirements (MW)				Zone K UCAP Prices (\$/kW-month)			NYCA UCAP Prices (\$/kW-month)			Cost Savings (\$000)		
Month	Total	@Zone K prices	@NYC A Prices	W/o Offshore	With Offshore	Price Reduction	W/o Offshore	With Offshore	Price Reduction	At Zone K Prices	At NYCA Prices	Total Savings
Jan-19	6,040	5,754	286	4.94	4.10	(0.83)	-	-	-	(4,803)	-	(4,803)
Feb-19	6,040	5,754	286	4.94	4.10	(0.83)	-	-	-	(4,803)	-	(4,803)
Mar-19	6,040	5,754	286	4.94	4.10	(0.83)	-	-	-	(4,803)	-	(4,803)
Apr-19	6,040	5,754	286	4.94	4.10	(0.83)	-	-	-	(4,803)	-	(4,803)
May-19	5,967	5,772	195	8.59	7.77	(0.82)	4.31	4.09	(0.21)	(4,752)	(41.09)	(4,793)
Jun-19	5,967	5,772	195	8.59	7.77	(0.82)	4.31	4.09	(0.21)	(4,752)	(41.09)	(4,793)
Jul-19	5,967	5,772	195	8.59	7.77	(0.82)	4.31	4.09	(0.21)	(4,752)	(41.09)	(4,793)
Aug-19	5,967	5,772	195	8.59	7.77	(0.82)	4.31	4.09	(0.21)	(4,752)	(41.09)	(4,793)
Sep-19	5,967	5,772	195	8.59	7.77	(0.82)	4.31	4.09	(0.21)	(4,752)	(41.09)	(4,793)
Oct-19	5,967	5,772	195	8.59	7.77	(0.82)	4.31	4.09	(0.21)	(4,752)	(41.09)	(4,793)
Nov-19	6,082	5,813	269	5.15	4.32	(0.83)	-	-	-	(4,853)	-	(4,853)
Dec-19	6,082	5,813	269	5.15	4.32	(0.83)	-	-	-	(4,853)	-	(4,853)
Total Savings										(57,432)	(247)	(57,679)

Table C-1. Capacity Price Impact of the hypothetical Offshore Wind Project. All numbers are in real 2013 dollars.

APPENDIX D

AWS Truepower

Annual Revenue Requirement: NY Offshore Wind



Memorandum

To: Dr. Guodong Sun, Stony Brook University
CC: Richard Tabors and Alex Rudkevich, TCR
From: Whitney Wilson, AWS Truepower
Date: 01 December 2014
Re: Annual Revenue Requirements – NY Offshore Wind

AWS Truepower completed an annual operating costs analysis for a hypothetical 252 MW offshore wind project. To determine the annualized costs, a review of previous capital and operations & maintenance (O&M) cost studies was completed. From these studies, an expected cost was determined and applied within a simplified financial model to understand the likely debt sizing and annual debt payments. The debt payments were then combined with the O&M assumptions to determine the annual operating costs at the project site.

FINANCIAL INPUTS FOR CAPITAL

A review of multiple studies was completed to identify the expected range of capital expenditures for offshore wind projects. As part of this literature review, we considered the overview provided by Stony Brook University in conjunction with the 2013 United States Department of Energy (DOE) National Renewable Energy Laboratory (NREL) technical report¹, the Crown Estate Report offshore guide², the Deutsche Bank UK Round 3 study³, and previous work completed on behalf of the New York Energy Research and Development Authority (NYSERDA).

1 United States Department of Energy, National Renewable Energy Laboratory. "Installation, Operation, and Maintenance Strategies to Reduce the Cost of Offshore Wind Energy." Technical Report NREL/TP-5000-57403. July 2013.

2 The Crown Estate. "A Guide to an Offshore Wind Farm." 2010.

3 Deutsche Bank Group DB Climate Change Advisors. "UK Offshore Wind: Opportunity, Costs & Financing." <https://www.dbcca.com/research>. November 2011.

Table 1. Review of Offshore Estimated Installed Costs per MW of Installed Capacity

STUDY	Price (\$/MW)
Stony Brook University Overview	2.3 Million – 6.8 Million
Crown Estate 2010 Guide	5.2 Million
NREL 2013 Study	5.7 Million
NYSERDA study	5.1 Million – 6.3 Million
Deutsche Bank Study	3.5 Million to 4.6 Million
Study Estimation	5.2 Million

Based on the information outlined in Table 1, we have applied a \$5.2 Million per MW estimate for the cost equipment and installation. This value included mobilization of installation (vessels, installation equipment, labor), equipment, landfall cable, port requirements, development costs and fees, initial land costs and voluntary payments.

REVENUE REQUIREMENTS FOR OPERATION

A review of multiple studies was completed to identify the expected range of turbine O&M expenditures for offshore wind projects. As part of this literature review, we considered the 2013 NREL technical report, the Crown Estate offshore O&M guide⁴, and previous work completed on behalf of NYSERDA.

Table 2. Review of Offshore Turbine O&M Costs per kWh of Generation

STUDY	Price (\$/kWh)
Crown Estate 2013 Guide	0.021
NREL 2013 Study	0.028
Work for NYSERDA	0.021
O&M Estimation	0.025

For the previous work for NYSERDA a value of \$0.021/kWh was assessed; however, the range identified was \$0.011/kWh to \$0.041/kWh. Based on this range and the values of the Crown Estate Guide and NREL Studies, we have applied a \$0.025/kWh estimate for the cost of turbine O&M expenditures. This value included mobilization of vessels and helicopter support, parts, and labor.

In addition to the turbine O&M, annual costs for Balance of Plant O&M, land rights, and administration expenses were considered. Approximately \$6.2 Million per year was estimated for the Balance of Plant facilities including offshore cabling and onshore connection facilities O&M, as well as annual lease payments for onshore facilities. Based on the commercial lease OCS-A 0486⁵ from the United States Department of the Interior (DOI) Bureau of Ocean Energy Management (BOEM), the 2019 lease rate of \$300,000 per annum was considered.

⁴ The Crown Estate, Scottish Enterprise, and GL Garrad Hassan. "A Guide to UK Offshore Wind Operations and Maintenance." 2013.

⁵ United States Department of the Interior, Bureau of Ocean Energy Management. "Commercial Lease of Submerged Lands for Renewable Energy Development on the Outer continental Shelf." OCS-A 0486.

Consideration was also made for administration expenses, such as general administration, permitting fees, community relations, insurance, and contingency. This was assumed to be \$5.35 Million, based on previous work completed for NYSERDA.

Table 3. Total Operational Expenses Estimated

Operational Expenses	Price (\$/year)
O&M	36.20 Million
Administrative	5.65 Million
<i>Final Estimation</i>	<i>41.85 Million</i>

In combination the final annual revenue requires for operation are estimated to be \$41.85 Million or \$0.040/kWh.

Requirements for Return on Capital

To determine the annual contribution of the capital expenditures and cash reserves, a simplified financial model was completed to estimate the annualized debt payment. Cash reserves were estimated to be approximately six months of debt payment plus approximately six months of operating expenses, or \$62.2 Million. This split was based on previous work completed for NYSERDA in conjunction with Sustainable Energy Advantage (SEA). The capital expenditures were combined with the cash reserves to estimate a total project cost of approximately \$1.37 Billion.

To complete the annual debt payment analysis with a conservative approach, we considered a 100 percent debt to 0 percent equity ratio for an 18 year loan term at a 7.0% interest rate. The total annual debt payment to cover the capital expenditures is estimated to be approximately \$136,240,000 or \$0.129/MWh.

Requirements for Return on Capital

To determine the final cumulative revenue requirements for a hypothetical 252 MW offshore wind project assuming the conservative debt to equity ratio and interest rate, we have combined the requirements for capital and operation per annum.

Table 4. Final Annualized Operating Costs Estimate

Annualized Expenses	Price (\$/year)
Operations	41.85 Million
Debt Payment	136.24 Million
<i>Final Estimation</i>	<i>178.09 Million</i>

The final revenue requirement is \$178.09 Million per year, which is equivalent to approximately \$0.169/kWh or \$169/MWh.

APPENDIX E

AWS Truepower

Unforced Capacity and Dependable Minimum Net Capability for NY Offshore Wind



Memorandum

To: Dr. Guodong Sun, Stony Brook University
CC: Richard Tabors and Alex Rudkevich, TCR
From: Whitney Wilson, Program Manager, Electrical Services
Date: December 1, 2014
Re: Unforced Capacity and Dependable Minimum Net Capability for NY Offshore Wind

AWS Truepower was retained to estimate the DMNC and Unforced Capacity (UCAP) values for a hypothetical 252 MW offshore wind facility to bid energy into the installed capacity market.

UCAP IN SYSTEM PLANNING

During the system planning process, studies will be completed to assess the region's resource adequacy requirements. The Loss of Load Expectation (LOLE) model is utilized to identify the target reliability levels. The model used in New York State is the Multi-Area Reliability Simulation Program (MARS), which was developed by GE for New York State and has since been implemented in other regions, including Midcontinent ISO (MISO) and Southwest Power Pool (SPP).

The LOLE model uses, among other inputs, the following key information: ICAP estimates, UCAP estimates, forced outage rates, planned maintenance rates, zone definitions, zone inertia limits, regional interface limits, forecasted load profiles, and uncertainty of forecasts. The analysis uses a Monte Carlo simulation to apply multiple potential random system events and iteratively adjust capacity until a convergence around a targeted level occurs. That targeted level is typically set to minimize system disturbances to 1-day in a 10-year period.

Dependable Maximum Net Capability (DMNC) is defined by the New York Independent System Operator (NYISO) as the sustained maximum net output as demonstrated by the performance of a test or from actual operation averaged monthly over a 12-month rolling period (Attachment J of the Installed Capacity Manual). The DMNC is the Installed Capacity (ICAP) value for the facility and is used in determining the Unforced Capacity (UCAP).

UCAP NEEDS ON LONG ISLAND

In July 2014, PSEG Long Island prepared a long range plan on behalf of the Long Island Power Authority. The PSEG Long Island Utility 2.0 Long Range Plan has identified the need for additional reliability generation in the South Fork area by the year 2019. This is due in part to a small growth of load, but primarily due to a reliance on generation from other parts of the island that are aging and becoming less reliable sources. The current design options show a 2019

peaking plant addition of two facilities: 10 MW at Montauk/Navy Rd and 15 MW to be determined for a total of 25 MW. An additional 100 MW of peaking units are expected to follow between 2021 and 2027, for a total of 125 MW of peaking units. Along with the peaking units, the plan includes 40 MW of solar energy through the Clean Solar Initiative II, 13 MW of DLC, and 2.5 MW of battery storage, microgrid and transmission network improvements. Combined, the plan has an expected cost of \$294 Million.

PSEG completed an analysis using a benchmark study and the NYISO demand curves to determine the avoided cost of capacity payments with the use of the Utility 2.0 Plan. For 2019, the avoided cost of capacity payments is shown in Table 1.

Table 1. Avoided Costs of PSEG Utility 2.0 Plan1

Calculation Method	Expected Avoided Cost Capacity (\$/kW-year)	Expected Avoided Cost Energy (\$/kWh)
Benchmark Study	160.76	0.054
Demand Curves	310.79	0.08

UCAP AND DMNC CALCULATIONS FOR OFFSHORE WIND

For a new wind facility, the DMNC is initially determined as the Installed Capacity net station losses (or electrical system losses). For the hypothetical 252 MW project, the electrical system losses at 100% of energy output were considered to be 3.0%. As such, the DMNC is 244.4 MW.

The Unforced Capacity that can be sold to the Capacity Market is defined monthly, based on a 12-month rolling calculation. The key equations, as set forth in Attachment J of the Installed Capacity Manual, are shown in Figure 1 below.

$$(1-1) \quad UCAP = (1 - EFORD) \times DMNC$$

$$(1-2) \quad EFORD = \frac{f_r \times FOH + f_p \times (EFOH - FOH)}{SH + f_r \times FOH}$$

$$(1-3) \quad f_r = \frac{\frac{1}{r} + \frac{1}{T}}{\frac{1}{r} + \frac{1}{T} + \frac{1}{D}}$$

$$(1-3a) \quad r = \text{average forced outage duration} = \frac{FOH}{\text{number of forced outages}}$$

$$(1-3b) \quad T = \text{average time between calls for a unit to run} = \frac{RSH}{\text{number of attempted starts}}$$

$$(1-3c) \quad D = \text{average run time} = \frac{SH}{\text{number of successful starts}}$$

$$(1-4) \quad f_p = \frac{SH}{AH}$$

Figure 1. UCAP Calculations

1 PSEG Long Island. "Utility 2.0 Long Range Plan." 1 July 2014. Pg A-3 and A-11.

Wind will have Unforced Capacity values based on seasonal performance factors calculated in accordance with section 4.5.1 of the ICAP manual. Unforced Capacity for wind will be based on the average production during hours 14:00 to 18:00 for the Summer (June, July, August) and hours 16:00 to 20:00 for the Winter (December, January, and February). Initially, the Unforced Capacity value for new wind will be based on the DMNC x the seasonal value as shown in Figure 2 below.

Unforced Capacity Percentage – Wind			
	Zones A through J	Zone K (land-based)	Zone K (off-shore)
Summer	10%	10%	38%
Winter	30%	30%	38%

Figure 2. Applicable Unforced Capacity Percentage – NYISO ICAP Manual Section 4.5

In accordance with section 4.2 of the Installed Capacity Manual from February 2014 and Section 5.12.8 *NYISO Services Tariff*, the DMNC Procedures require a new resource to qualify as Installed Capacity Suppliers. This includes providing results from an appropriate DMNC Demonstration or registration as a Special Case Resource (SCR) prior to participating as an Installed Capacity Supplier in the NYISO Installed Capacity market. The DMNC value will be required to be validated and approved by NYISO based on DMNC value tests. The Summer Capability period is listed as May through October and the Winter Capability Period is from November through April. Tests can be completed in Out-of Period timelines (March 1 through June 1 for the Summer Capability Period and September 1 through November 1 for the Winter Capability Period), but they must be verified with a test in the next DMNC test period. The test determines the DMNC value as the net of any station service load, with the addition of any resource specific requirements.

Average Coincident Load (ACL) is one of the key parameters of the testing period. Provisional ACL will be determined during the Demonstration or SCR period. The Provisional ACL may be applicable for a maximum of three (3) consecutive Capability Periods from the first capability Period the SCR has enrolled in.

The Provisional ACL will use in-period verification based on 40 peak load hours. Once in-period verification has been completed, the provisional status will be eliminated. If all 40 hours are reported in the first Capability Period after enrollment, the verification will be complete. For a specific period, if 20 or more hours Zone Peak Hours, but less than 40, are reported as part of the in-period verification process, the NYISO shall calculate the ACL for the in-period verification using the resource’s highest 20 hourly loads to adjust the Provisional ACL; however, the ACL will remain provisional for the following Capability Period. For fewer than 20 Zone Peak Hours are available in the reported data, the relevant metered load from the Meter Installation Date through the end of the Capability Period will be used to determine the ACL; however, the Provisional ACL will be used in calculations. If the facility fails to provide data, each hour of the failed data will be set to zero and the calculated value will be used in the calculation. (4.12.4.2 of the Installed Capacity Manual).

For the hypothetical project, the initial Unforced Capacity will be 244.4 MW*38% or 92.9 MW for both Summer and Winter. After the DMNC testing has completed through at least one of each season or three Capability Periods, the DMNC will be based on historical data².

UCAP SAVINGS ATTRIBUTED TO OFFSHORE WIND

By having additional UCAP available from renewable generation facilities, the simulation may find a more limited or delayed need for additional reliability generation, such as peaking units. However, the affect on this offset or delay is highly determined by the other inputs.

Using the values in Table 1 above, which were calculated as part of the Utility 2.0 plan and are located on pages A-3 and A-11 of the PSEG report, we made a broad estimation of the potential capacity and energy cost savings should 92.9 MW (or later 104 MW) of UCAP from the plan be replaced with offshore wind in the region. The results in Table 2 are based on a straight calculation of the PSEG range of cost savings and the estimated UCAP values, both discussed above.

Table 2. Broad Estimation of Potential Avoided Cost Savings Attributable to Offshore Wind

	92.9 MW UCAP		104 MW UCAP	
	Benchmark	Supply	Benchmark	Supply
UCAP (kW)	92,900	92,900	104,000	104,000
Energy (kWh/yr)	1,056,131,866	1,056,131,866	1,056,131,866	1,056,131,866
Avoided Cost Calculation				
<i>Capacity</i>	\$ 14,934,604.00	\$ 28,872,391.00	\$ 16,719,040.00	\$ 32,322,160.00
<i>Energy</i>	\$ 57,031,120.76	\$ 84,490,549.28	\$ 57,031,120.76	\$ 84,490,549.28
Total	\$ 71,965,724.76	\$ 113,362,940.28	\$ 73,750,160.76	\$ 116,812,709.28

Sources:

- NYISO. "Installed Capacity Manual." February 2014.
- NYISO. "Attachment J: Installed Capacity Manual." February 2014.
- NYISO. "KCC Conference NYISO DMN presentation by the Market Training Group." 17 March 2010.
- PSEG Long Island. "Utility 2.0 Long Range Plan." 1 July 2014.

² AWS Truepower completed an estimate based on the Hours/Seasons discussed in section 4.5 of the ICAP manual and estimated production for the facility from historical resource data. Based on the analysis, the UCAP based on historical data considered for the facility beyond the initial term is expected to be increased to 104 MW.