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REPORT AND RECOMMENDATIONS COMPARING REPOWERING OF DUNKIRK POWER LLC AND TRANSMISSION SYSTEM REINFORCEMENTS

Case 12-E-0577 – Proceeding on Motion of the Commission to Examine Repowering Alternatives to Utility Transmission Reinforcements

MAY 17, 2013

nationalgrid

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I. Executive Summary

In the January 18, 2013 Order Instituting Proceeding and Requiring Evaluation of Generation Repowering ("Repowering Order") the New York State Public Service Commission asked National Grid to compare the costs and benefits of repowering the NRG Dunkirk generation facility against implementing transmission upgrades proposed to address retirement of the plant, and to report the results of that analysis to the Commission with a recommendation for action.

Based on its analysis, the Company recommends the Commission support the implementation of the Transmission Upgrades solution. To arrive at its recommendation, the Company first considered whether a proposed option met the reliability needs. The Transmission Upgrades, as well as Repowering Options 1 and 2, each satisfactorily addresses the reliability needs resulting from closure of Dunkirk. Therefore, for each of these options, the Company looked at costs to customers, market effects, other economic impacts (*e.g.*, jobs), and environment impacts.

The Transmission Upgrades resulted in the lowest costs to customers, producing delivery cost increases of 0.5% for residential customers to 1.3% for the largest customers. Under Repowering Option 1, residential customers would observe a 3.5% increase and the largest customers would see increases of 9.5%. If the repowered units are impacted by future market mitigation rules during the proposed contract period, the delivery rates could increase to 5.3% for residential customers and 13.9% for large industrial customers.

When evaluating market effects of the proposed repowered generation, the primary factor considered to assess economic efficiency of that market entry was the effect on system generation production costs. Generator production cost estimates are preferred to projections of energy and capacity market effects for assessing economic efficiency of a proposed generation project because entry of a new generator into the competitive market would likely cause a market response which is not captured in most energy and capacity market forecasting analyses. For example a single market response such as a retirement of another market participant's generator could largely or completely offset any forecasted energy or capacity market savings. The Repowering Options would result in generation production costs that actually increase rather than decrease when compared to a base case. This is due to the fact that, because of its location, much of the generation produced by the repowered Dunkirk plant is projected to be exported to PJM (west) rather than consumed in New York State.

The Company also looked at the impact of the different reliability options on economic factors such as job creation. Construction spending under each of the options has temporary positive economic impacts, and on-going O&M spending under the Repowering Options create considerably more jobs than O&M expenditures associated with the Transmission Upgrades. However, impacts on electric rates also have a significant effect on jobs over the study period. The Company's analysis in this area indicates that Repowering Option 1 creates the most jobs during the construction phase when compared to Repowering Option 2 and the Transmission Upgrades (which have roughly comparable construction-related job creation). However, the costs and resulting rate impacts of Repowering Option 1 would result in the highest number of job losses during the study period. Job impacts from Repowering Option 2 and the Transmission Upgrades during the study period are close, with Repowering Option 2 projected to produce a small number of jobs (due to relatively high O&M spending), while the Transmission Upgrades would result in a small number of job losses. It should be noted, however, that any negative job impacts calculated by the economic models are far less than the adverse economic results that could occur if the reliability investments were not made and the region experienced resulting reliability problems.

Regarding environmental effects, the Company's analysis suggests there is insufficient basis for differentiating among Repowering Options 1 and 2 and the Transmission Upgrades on the basis of environmental performance.

Based on the analysis summarized in this report, the Company recommends the Commission support the Transmission Upgrades to address the reliability needs at the lowest overall cost, least risk to customers, and with minimum impact on competitive markets. The regulated nature of the Transmission Upgrades also provides for greater transparency of and scrutiny over the investments that are being made for the benefit of customers. Such transparency and oversight assures that customers pay no more than what is just and reasonable for reliable electric service.

The Company does not oppose generation repowering in principle; however, repowering at the Dunkirk facility is not in the best interest of customers. In addition, repowering under the commercial structure proposed by NRG would shift significant risk back to customers and away from the competitive market, which is contrary to key principles underlying the Commission's move to more competitive electricity markets. The Company's conclusion that customers should not bear the market risk of repowering in this case does not preclude NRG from pursuing repowering on its own, without customer subsidization, if NRG concludes repowering Dunkirk presents a reasonable market opportunity.

II. Background

A. Dunkirk Mothballing Announced

On March 14, 2012, NRG Energy, Inc. ("NRG"), the owner of Dunkirk Power LLC ("Dunkirk"), filed notice with the Commission of NRG's intent to mothball the Dunkirk facility no later than September 10, 2012. Based on forecasted wholesale electric prices, NRG stated that Dunkirk was not "economic and [was] not expected to be economic . . . ." Based on transmission system studies, National Grid determined that Dunkirk units 1 and 2 were needed for an interim period to maintain system reliability until permanent transmission system reliability solutions could be implemented. Accordingly, the Company entered into a Reliability Support Services contract with

Dunkirk for the period September 1, 2012 to May 31, 2013 ("2012 RSS Agreement"). The estimated cost of the 2012 RSS Agreement is approximately $37 million.

National Grid is implementing certain near-term transmission projects that will reduce the reliability need for Dunkirk generation from two units to one unit by May 31, 2013. However, transmission solutions that could reduce reliance on Dunkirk generation to maintain area reliability altogether cannot be completed before June 1, 2015. Therefore, to maintain system reliability in the interim, the Company and Dunkirk entered into a second RSS Agreement for the period June 1, 2013 to May 31, 2015 ("2013 RSS Agreement").[1] Cost of the 2013 RSS Agreement is approximately $72.7 million.

B. Repowering Order and RFP

On January 18, 2013, the PSC issued an Order Instituting Proceeding and Requiring Evaluation of Generation Repowering ("Repowering Order") in response to the New York Energy Highway Task Force Blueprint.[2] The Repowering Order directs National Grid and New York State Electric and Gas ("NYSEG") to analyze repowering as an alternative to transmission system upgrades when a facility needed for reliability proposes to retire. Specifically, the Repowering Order requires the utilities to "examine the relative costs and benefits of repowering the plants at their existing sites, and compare those costs and benefits to the costs and benefits of alternative transmission upgrades over the long term."[3] The period of study must be at least 10 years.

Under the Repowering Order, the utilities are required to identify transmission investments to address reliability issues resulting from closure of the Dunkirk and Cayuga generating stations, and to solicit proposals from the current generator owners for repowering the plants to meet system reliability needs. The utilities must evaluate the repowering options and transmission upgrades and submit their respective report and recommendations to the Commission. The utilities are to compare the generation repowering and transmission upgrades on the basis of:

- Reliability – Each proposed solution (transmission upgrade or generation repowering) should be evaluated on how effective it is expected to be in alleviating the identified reliability problems, and in reducing load shed risk, over the long run.
- Other Impacts – Each proposed solution should be evaluated in terms of its potential impacts on:
    - Ratepayer costs.
    - The environment.
    - The economy (e.g., temporary and permanent jobs, economic development, and tax revenue).
    - Electric market competiveness.

[1] The 2013 RSS Agreement was approved by consent by the Commission at its May 16, 2013 session.
[2] New York State Energy Highway Task Force, New York State Energy Highway Blueprint (2012) ("Energy Highway Blueprint").
[3] Repowering Order, p. 3.

- o Any other factors that should be considered in weighing the costs and benefits of the proposed reliability solutions.

On February 15, 2013, the Company submitted a list of five (5) transmission projects needed to address the long-term reliability concerns raised by the shutdown of the Dunkirk plant. The five projects are:

1. Addition of two 33.3 MVAr capacitor banks on the two Dunkirk 115kV bus sections ($2.5 million).
2. Addition of a second 75 MVAr capacitor bank at the Huntley 115kV switchyard ($1.4 million).
3. Reconductoring of the two 115kV lines between Five Mile Road and Homer Hill, each approximately 7.4 miles in length ($18.0 million).
4. Reconductoring 14 miles of the Packard – Erie #181 115 kV line ($37.1 million).
5. Reconductoring one mile of the Niagara – Gardenville #180 115 kV line ($4.0 million).

Implementing these projects is expected to address all N-1 reliability problems and greatly mitigate N-1-1 reliability exposure resulting from the shutdown of Dunkirk through at least 2021.

On February 19, 2013, National Grid issued a request for proposal ("RFP") to NRG seeking information on the potential repowering of the Dunkirk station. On March 26, 2013, NRG responded to the RFP proposing three repowering options. These are:

- Option 1—a new 422 MW combined-cycle gas turbine (CCGT) and the refueling the existing 75 MW Dunkirk unit 2 with natural gas.
- Option 2—the refueling of the existing Dunkirk units 2, 3 and 4 with natural gas.
- Option 3—installation of 285 MW of natural gas-fired peaking units.

Each option proposed by NRG includes different commercial and schedule terms, and has different effects with respect to projected reliability, environmental and economic impacts.

C. Evaluation Methodology

The primary consideration in evaluating each proposed solution is whether it satisfies the reliability need. If a proposed solution meets the reliability need, the Repowering Order requires evaluation "in terms of its potential impacts on: (a) ratepayer costs; (b) the environment; (c) the economy (e.g., temporary and permanent jobs, economic development, and tax revenue); (d) electric market competiveness; and (e) any other factors the reporting utility believes should be considered in weighing the costs and benefits of the alternatives."[4]

The timeframe used for the evaluation is the 10-year period from June 1, 2015 to May 31, 2025. This period aligns with the need to have reliability solutions implemented by June 1, 2015 to coincide with the expiration of the 2013 RSS Agreement. To the extent a reliability solution could not be implemented by June 1, 2015, interim or

[4] Repowering Order, pp. 3-4.

supplemental reliability measures would be needed until the respective reliability solution is in place. This report and recommendation does not attempt to quantify any additional costs, reliability impacts, or any other effects of having to implement interim or supplemental reliability measures.

National Grid asked 31 formal information requests and also met with NRG to obtain more information about the proposals. The Company used the information provided by NRG to estimate the costs of the Repowering Options and the Transmission Upgrades and estimated customer bill impacts of the different reliability solutions. The Company also estimated other economic benefits (*e.g.*, job creation) under the different alternatives using the REMI model.

To better understand the impacts of the proposed Repowering Options, the Company retained the PA Consulting Group. PA Consulting used the GE-MAPS model to project impacts on generation production costs, wholesale energy market impacts, and emissions; and it used its own installed capacity ("ICAP") model to project ICAP costs. PA Consulting also performed a limited literature review of economic impact analysis models.

The Company also retained Atlantic Economics LLC to address fundamental economic considerations for evaluating new generation market entry, and to provide an expert opinion on whether electric customers should bear the costs of the Repowering Options based on the projected impacts of the those options.

The Company used a net present value ("NPV") analysis of net benefits over 10 years to compare the relative benefits to consumers of the alternatives considered.

National Grid has attempted to present this evaluation in the most transparent manner possible; however, because NRG has characterized much of the information included in its repowering proposal and its related discovery responses as confidential, there are portions of the evaluation that have been redacted.[5]

III. Evaluation of Reliability Solutions

A. Proposed Reliability Solutions

National Grid evaluated three Dunkirk repowering options and one set of transmission upgrades for this report. These are:

Repowering Option 1—A new 422 MW combined cycle gas turbine ("CCGT") located on the 230 kV network, and the refueling of Dunkirk Unit 2 (75 MW) on natural gas and located on the 115 kV system. According to NRG, the CCGT

[5] Copies of Dunkirk's repowering proposal and discovery responses are provided as Appendix 1 and Appendix 2 to this report, respectively.

could be in-service by mid-2017, with Dunkirk Unit 2 refueling occurring in 2015.

Repowering Option 2—NRG would add natural gas-firing capability to Dunkirk units 2, 3 and 4 and provide 455 MW of generation.

Repowering Option 3—NRG would install 285 MW of new gas-fired peaking units, capable of full-load operations in 10 minutes.

Transmission Upgrades—National Grid would implement three transmission projects as of June 1, 2015 to avoid the need for continued reliance on the 2013 RSS Agreement upon its scheduled termination (May 31, 2015), and two longer-term transmission projects to address longer-term reliability needs that remain after that date. The five projects are:

- Two new 33.3 MVAr capacitor banks on the two Dunkirk 115kV bus sections.
- One new 75 MVAr capacitor bank at the Huntley 115kV switchyard.
- Reconductoring of the two 115kV lines between Five Mile Road and Homer Hill, each approximately 7.4 miles in length.
- Reconductoring one mile of the Niagara – Gardenville #180 115 kV line.
- Reconductoring 14 miles of the Packard – Erie #181 115 kV line.

B. Reliability Evaluation

Satisfying the identified reliability need is the threshold consideration for a proposed solution. Only if it passes the reliability screen is a proposed solution considered further. Of the four solutions considered, Repowering Options 1 and 2 and the Transmission Upgrade would satisfy the relevant NERC, NPCC, and NYSRC reliability criteria. Repowering Option 3 does not meet the reliability needs. Absent transmission upgrades, the generation resources needed at Dunkirk to address the low voltages and overload conditions that would develop over the study horizon are in the range of 400 – 450 MW, depending on the interconnection configuration. In a discovery response (NMPC-13), NRG indicated that it could not provide a revised Repowering Option 3 bid in time to be considered for this submission. Because it does not meet the reliability needs identified in the RFP, Repowering Option 3 is not considered further in this report.

1. Reliability Considerations of System Studies

National Grid's current transmission system in western New York is vulnerable to low voltages during transmission outage conditions. These vulnerabilities are present with and without generation at Dunkirk in service; however, they are more severe when Dunkirk generation is not in service. To address low voltage conditions that exist even with Dunkirk generation in service, National Grid developed a set of transmission upgrades that are expected to be completed by June 2015.

Following NRG's announcement that it was placing Dunkirk station in protective layup (*i.e.*, mothball), further studies were done. These studies determined that additional transmission projects would be necessary to address post-contingency low voltages and thermal overloads that would develop if the Dunkirk station were not in service. These transmission projects were in addition to those originally identified to address system concerns present with Dunkirk in service. The studies also examined the level of generation necessary at Dunkirk to prevent low voltages and overloads from developing and were used to specify the generation requirements for the repowering of Dunkirk.

The intent of the studies of both the Transmission Upgrades and the Repowering Options was to develop a system that could reliably operate for any design contingency, including N-1-1 conditions. Based on these studies, Repowering Options 1 and 2, as well as the Transmission Upgrades, would result in acceptable system performance for design contingencies. Neither the Repowering Options nor the Transmission Upgrades would require load shedding for N-1 or N-1-1 reliability conditions for the 10-year horizon of the system studies.

The first three projects under the Transmission Upgrades (Dunkirk and Huntley capacitor banks and reconductoring between Five Mile Road and Homer Hill substations) are planned to be in service by June 1, 2015. Implementing these three projects by June 1, 2015 would obviate the need to rely on Dunkirk after the expiration of the 2013 RSS Agreement. The Company estimates the next two projects (reconductoring on the #180 and #181 lines) could be in service no later than 2018 - 2019. These two projects are designed to address additional thermal overload conditions resulting from the Dunkirk shutdown. The Company would rely upon operational measures to address any reliability issues remaining in the period following completion of the first three projects (estimated at June 1, 2015) and before the completion of the #180 and #181 line reconductoring.

Although the Repowering Options and the Transmission Upgrades are not identical in all aspects of system performance, they nevertheless each satisfy the minimum reliability criteria requirements and would result in similar reliability performance of the transmission system in western New York over the study horizon.

2. Longevity of Solutions

The respective longevity of the Transmission Upgrades and Repowering Options were not reviewed so it is unknown if additional upgrades would be required outside the 10-year study horizon. It is possible that a need could develop following completion of any of the solutions that would require further system upgrades. For the Repowering Options, it was noted that for some dispatch conditions the loading on the 115 kV Packard – Erie #181 line continued to be above 95%, but less than 100% of its Long Term Emergency rating for a double circuit tower outage of the #180 and #182 circuits. These concerns were not noted for the Transmission Upgrades, as reconductoring of the #181 circuit is included in the proposed plan.

3. System Operations and Effect on Inter-regional Flows

Locating generation at Dunkirk would facilitate economic exports from (or through) New York to PJM (west). Dunkirk generation alleviates loading on the 115kV system and mitigates constraints between Gardenville and Dunkirk under some high export conditions. However, once that 115 kV constraint is lifted and there are high transfers from generation in Ontario or Northwest New York attempting to pass through the New York transmission system to PJM (west), constraints could develop in other areas of the 115 kV or 230 kV system in this region. To address such a situation and facilitate increased cross-border flows, a transmission solution with increased transfer capability (that likely incorporates reconductoring of the 115kV lines between Gardenville and Dunkirk and potentially some 230 kV modifications between Dunkirk and South Ripley), or a hybrid solution involving both generation and transmission, could be implemented.[6]

Past system operation has also identified that during periods of high import from PJM (west) into New York, similar constraints on the 115 kV system could develop, but in the opposite direction. Prior to the recent mothballing of generation at Dunkirk, system operators would reduce the output of Dunkirk to alleviate this constraint on the 115 kV system. It is expected that this condition would also be present for the Repowering Options.

4. Circuit Availability

The reconductoring of the Five Mile – Homer Hill circuits, the Packard – Erie #181 circuit and the Niagara – Gardenville #180 circuit under the Transmission Upgrades are expected to result in limited improvement in the availability of these circuits. By replacing the conductor and potentially replacing structures, insulators and other hardware, it is expected that fewer failures of these pieces of equipment would occur. The improvement in the performance of the 115 kV transmission lines may not necessarily translate to improved reliability of supply to customers (as measured by SAIFI or CAIDI) but reducing equipment outages and failures will improve overall system operation.

The Five Mile – Homer Hill circuits do not directly supply any load stations and thus that project would not improve SAIFI or CAIDI.

For the stations supplied by line #181, most have two transmission supplies, two step down transformers and a closed low side bus tie. For a transmission line outage, no customers are impacted, even momentarily. For those customer-owned stations supplied by line #181 that do not operate with a closed low side bus tie, it is possible for them to swap their load from one transmission supply to another. Thus, these customers' loads would see only a momentary outage until the alternate supply was energized. Other

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[6] A detailed study looking at this situation or any potential solutions would need to be performed to confirm the actual level of increased export capability.

stations supplied by this line are 115/34.5 kV step down stations that feed part of a 34.5 kV network. So outages of the transmission supply again have no impact on the reliability of supply for customers, as the other sources into the 34.5 kV network continue to supply the load.

For the #180 reconductoring project, the scope is small, only one mile of a 31.5 mile long circuit, and therefore the improvements would statistically be very limited. However the only distribution station supplied by this line has two transmission supplies and a single step down transformer. An outage of line #180 would result in a momentary outage to load customers until the alternate supply could be energized.

Following completion of the reconductoring of these lines, an outage of any one would be somewhat less likely to occur. However, this would have almost no impact on the reliability of supply to any load customers.

Because the Repowering Options do not involve the reconductoring of any circuits, those options would not result in any improvement in the performance of any transmission system circuits.

Based on the Company's analysis as summarized above, the relative circuit reliability performance under Repowering Options 1 and 2 and the Transmission Upgrades does not provide a sufficient basis for differentiating among the alternatives.

C. Costs to Customers

For proposed solutions that satisfy the reliability screen, the primary factor to consider is the cost to customers. The cost to customers of a prospective reliability solution is the cost to be recovered through regulated delivery rates (*e.g.*, the traditional revenue requirement associated with the Transmission Upgrades), or the contract costs required to finance the Repowering Options. Delivery costs under the Transmission Upgrades are relatively easy to determine based on the estimated investment levels and use of traditional cost of service methods and cost allocation. Delivery costs under the Repowering Options are estimated based on indicative commercial terms proposed by NRG,[7] as well as forecasts for fuel, property taxes and others costs.

A customer's supply cost (*i.e.*, the costs of energy, capacity, ancillary services) is more significantly influenced by the competitive markets than delivery costs. Factors such as fuel costs (*e.g.*, natural gas), generation market entries and exits, and customer demand, can have large impacts on market price forecasts and the resulting customer supply costs. The impact on customer costs due to changes in the competitive supply market also depends on the degree to which customers may be "hedged," or involved in

[7] Because costs and other commercial terms under Repowering Options 1 and 2 have been designated by NRG as confidential, a detailed component breakdown of the projected cost effects under the Repowering Options is not provided in a publicly available format. Instead, the projected costs under these options are presented in a way intended not to reveal the information designated confidential.

bilateral contracts. Hedging has the effect of insulating customers from changes in the market or attenuating the effects.

The Company addresses delivery and supply cost considerations separately in the sections below.

1. <u>Delivery Cost Effects</u>

For the Repowering Options, the estimated one-year (2018)[8] and study horizon (10 years, June 2015 – June 2025) impacts on customers' delivery costs were determined in part using the indicative contract pricing and commercial terms information provided by NRG in its repowering proposal for Repowering Option 1. The Company also applied market forecasts of energy, capacity, and natural gas prices, as well as estimates of emissions costs, property taxes, and an assumed capacity factor for the generating units operating under out-of-market support agreements, to arrive at estimated annual total and net costs to customers for Repowering Options 1 and 2.[9] "Net costs" are defined as the total respective Repowering Option contract costs less any revenue received under the respective out-of-market contract.

Under Repowering Option 1, the total cost to customers under the contract over the 10-year study period would be [redacted] [10] Based on estimated total revenues over the period, the net costs of the Repowering Option 1 contract would be [redacted] or $375 million on a 2013 NPV basis. For Repowering Option 2, the total cost to customers under the contract over the 10-year study period would be [redacted] Based on estimated total revenues over the period, the net costs of the Repowering Option 2 contract would be [redacted] or $218 million on a 2013 NPV basis.

A summary of total and net costs under the Repowering Options is provided in Exhibit 1. A redacted version of the total and net cost determinations showing all inputs and setting forth the component costs under the Repowering Options is provided in Exhibit 2. It should be noted that the "net costs" under the Repowering Options contracts assume that the capacity bids of the repowered units are not "mitigated" by the NYISO. To the extent capacity bids of the repowered units are mitigated at any time during the study period, customers would bear the risk that the market revenues available to the units would decrease and the net costs of the contracts would increase.[11]

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[8] The year 2018 was chosen for the one-year comparison among alternatives because it is the first full year all costs under either Repowering Option would be in effect. For purposes of the analysis, it was assumed that all Transmission Upgrades costs were also in effect in 2018.

[9] The LEG report did not consider or include any of the costs to customers of the Repowering Options (NMPC-21 and NMPC-22).

[10] Option 1 requires a [redacted] to support the CCGT, [redacted]

The Independent Power Producers of New York, Inc. ("IPPNY"), recently filed a complaint with the Federal Energy Regulatory Commission ("FERC") asking FERC to impose mitigation on Dunkirk's participation in the capacity market administered by the New York Independent System Operator ("NYISO") (*IPPNY v. NYISO*, FERC Docket No. EL13-62). IPPNY seeks relief to address what it calls the "artificial suppression of prices in the NYCA ICAP Spot Market Auctions" related to ICAP market

For the Transmission Upgrades, the Company determined a total estimated revenue requirement associated with the five identified transmission projects. The first three projects (Dunkirk and Huntley capacitor banks and reconductoring between Five Mile Road and Homer Hill substations) are included in the Company's current capital investment plan, and are planned to be in service by June 1, 2015. The total costs of these three projects ($21.9 million) reflect conceptual grade engineering estimates (-25% to +50%). The next two projects (reconductoring on the #180 and #181 lines) are not in the Company's current capital plan. The Company estimates these projects could be placed into service no later than 2018 - 2019. The total costs of these two projects ($41.1 million) reflect preliminary investment grade engineering estimates (-50% to + 200%). Because Dunkirk's RFP response indicates that at least one of its Repowering Options could be in place by June 1, 2015, it may be possible for the Company to avoid the costs of materials and construction for the three nearer term projects (capacitor banks and Five Mile Road to Homer Hill reconductoring), as well as all costs of the two longer term projects (lines #180 and #181 reconductoring). Therefore, the Company included the costs of all five of the projects in the evaluation against the repowering alternatives.

The Company calculated the revenue requirement using factors approved in its most recent electric rate case (Case 12-E-0201) to establish a total annual carrying charge (16.76%) to apply to capital investments, as shown in Exhibit 3. The Company first multiplied the annual carrying charge associated with the "return on" the capital investment by the total average annual net book value for the five transmission projects. Next, the Company multiplied the annual carrying charge associated with the "return of" the capital investment by the total capital investment amounts. Included in the second calculation were O&M costs based on factors approved in the Company's electric rate case. The two calculated returns were then combined to arrive at a total revenue requirement for 2018, which was assumed to be the first year all projects were in service.[12] The same calculation was prepared for the 10-year study period to determine the total 10-year revenue requirement for the Transmission Upgrades. The estimate of the annual costs of the Transmission Upgrades and the detailed derivation of those costs is provided in Exhibit 3.

A comparison of the total and net costs under the Repowering Options and Transmission Upgrades is provided in Table 1.

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participation by Dunkirk in connection with the 2012 RSS Agreement. IPPNY Complaint, at 2. NRG is a member of IPPNY.

[12] The Company used the current project cost estimates to determine a mid-range revenue requirement and the upper bound of the range of project estimates (+50% for the capacitor projects and 5-Mile Road to Homer Hill lines, and +200% for the #180 and #181 lines) to determine a high-range revenue requirement. See Exhibit 3.

Table 1. Comparison of Estimated Total and Net Costs under Repowering Options 1 and 2 and the Transmission Upgrades

One-Year Costs (2018)	Repowering Option 1	Repowering Option 2	Transmission Upgrades
Annual Total Costs	[redacted]	[redacted]	$10.5 M
Annual Revenues[13]			N/A
Annual Net Cost			$10.5 M
Study Period (10 years)			
Total Costs	[redacted]	[redacted]	$102 M
Estimated Revenues			N/A
Net Cost			$102 M
NPV of Net Costs	$375 M	$218 M	$70.5 M

To determine the impact on delivery costs, the Company assumed the costs of the Repowering Options and the Transmission Upgrades would be recovered from Niagara Mohawk customers based on the cost allocation mechanism currently in effect for RSS costs. Use of this allocation methodology is solely for the purposes of providing a consistent basis for comparison and is not intended to reflect the Company's position on cost allocation or recovery with respect to the Repowering Options. To the extent the Commission directed implementation of a reliability alternative on the basis of benefits accruing to customers of other utilities or regions not served by Niagara Mohawk, the recovery of costs for such alternative also should be allocated on a broader basis. If cost allocation and recovery are evaluated over a different or broader base (*e.g.*, all New York electric customers), such cost recovery mechanism would change the cost per customer, but would not change the total cost of the alternative.

Subject to the foregoing, the Company translated respective cost impacts into rate impacts assuming recovery of the respective 2018 one-year costs from Niagara Mohawk customers in accordance with the RSS surcharge mechanism currently in place. The Company then calculated the rate and bill impacts for customers assuming capacity revenues based on forecasted capacity market prices (Exhibit 4) and assuming no capacity revenues as a result of capacity bid mitigation (Exhibit 5). Table 2 below summarizes the resulting delivery bill impacts of the Repowering Options and Transmission Upgrades.

[13] Estimated revenues reflect anticipated revenues in the capacity markets assuming the repowered units operate at their projected capacity factors throughout the respective period, there is no competitive market response to new entry, and offers are not subject to mitigation. In the event capacity factors are below projections, or capacity offers are mitigated during the respective periods, estimated revenues would decrease and net costs would increase.

Table 2. Estimated Delivery Bill Impacts of Repowering Options and Transmission Upgrades

No Mitigation	Repowering Option 1	Repowering Option 2	Transmission[14] Upgrades
Delivery Bill impact (2018) – SC-1	3.6%	1.7%	0.5%
Delivery Bill impact (2018) – SC-2ND	4%	1.8%	0.6%
Delivery Bill impact (2018) – SC-2D	5.1%	2.3%	0.7%
Delivery Bill impact (2018) – SC-3 (primary)	7.2%	3.3%	1%
Delivery Bill impact (2018) – SC-3A (transmission)	9.5%	4.4%	1.3%
Assuming Capacity Bid Mitigation			
Delivery Bill impact (2018) – SC-1	[redacted]	[redacted]	0.5%
Delivery Bill impact (2018) – SC-2ND	[redacted]	[redacted]	0.6%
Delivery Bill impact (2018) – SC-2D	[redacted]	[redacted]	0.7%
Delivery Bill impact (2018) – SC-3 (primary)	[redacted]	[redacted]	1%
Delivery Bill impact (2018) – SC-3A (transmission)	[redacted]	[redacted]	1.3%

2. <u>Supply Cost Considerations</u>

National Grid retained PA Consulting Group ("PA Consulting") to assist with evaluating the Repowering Options as well as the study by NRG's consultant, Longwood Energy Group LLC ("LEG"). PA Consulting analyzed the effects of Repowering Options 1 and 2 and the Transmission Upgrades on generation production costs, wholesale energy markets, and emissions performance using the GE Multi-Area Production Simulation Software ("GE-MAPS"). PA Consulting also evaluated impacts on the capacity market using its own ICAP model and considered the regional economic impact projections presented in the LEG study compared to other publicly available economic impact analysis models.[15] A copy of the PA Consulting report is included in Exhibit 6. The Company summarizes the result of the PA Consulting analyses regarding

[14] Based on mid-range revenue requirement.
[15] National Grid also performed its own evaluation of regional economic impacts, as described in Section III.D, *infra.*

production costs, wholesale energy markets, and capacity markets immediately below. Regional economic effects and emissions performance are discussed in Sections III.D and III.E, respectively.

a. Production Costs Savings

Michael Cadwalader of Atlantic Economics was retained by the Company to describe the process that should be used to determine whether generation investment is in the interest of consumers. According to Mr. Cadwalader, one of the principal metrics for assessing consumer benefits of generation investment is the effect on production costs. Production costs are the costs to generators of producing electricity and represent the costs paid by the energy market as a whole. Therefore, to the extent overall production costs decrease, the overall cost of energy decreases and consumers are benefitted by the amount of the decrease.

The GE-MAPS model used by PA Consulting projected that annual generation production costs under Repowering Option 1 would actually *increase* in New York State on average approximately $16 million/year (2012$), and increase by $122 million over the study period. The reason adding new, low heat rate generation would actually increase production costs in New York State is that because of its location, much of the new generation output is expected to be exported to neighboring regions, primarily PJM (west). The production cost results determined by PA Consulting using the GE-MAPS model take into account the effect of cross-border transactions and flows in the energy markets. The LEG study, on the other hand, assumed that the volume of cross-border flows was unaffected by the repowering project.[16] Table 3 provides a summary of generation production cost estimates for Repowering Options 1 and 2.

Table 3. Generation Production Costs for Repowering Options 1 and 2.

	Repowering Option 1	Repowering Option 2
	NYCA	NYCA
Average Annual Production Cost Savings	-$16 million	-$55 million
NPV of Production Cost Savings over study period	-122 million	-430 million

A detailed description of PA Consulting's production cost analysis is included in Exhibit 6.

b. Wholesale Energy Market Projections

Using GE-MAPS, PA Consulting found that Repowering Option 1 may produce statewide average annual wholesale market energy savings of $9 million/year, and

[16] Based its assumption of no change in cross-regional flows, LEG estimated $28 million in average annual production cost reductions and $281 million in reduced production costs over 10 years.

savings of $97 over the study period. For Repowering Option 2, PA Consulting projected an average annual wholesale market energy cost *increase* of $7 million/year across New York State, as well as an NPV increase of $7 million over the study period.[17] By comparison, LEG's study projected that Repowering Option 1 would produce average annual wholesale market energy savings of $142 million/year across New York State $1.4 billion over 10 years.

Similar to the case with production costs, the large differences in results between PA Consulting and LEG are likely attributable to simplifying assumptions made by LEG with respect to the effect of cross-border transactions in the energy markets. While the LEG study assumed that the volume of cross-border flows was unaffected by the repowering project, the GE-MAPS model actually accounts for changes in inter-regional flows produced by energy price changes.

c. Capacity Market Projections

PA Consulting found that Repowering Option 1 may produce average annual capacity market savings across New York State of $50 million/year, and $560 million over the study period. For Repowering Option 2, PA Consulting actually projected greater ICAP savings than in Repowering Option 1 due to the fact that under Repowering Option 2, new capacity is added sooner. For Repowering Option 2, PA Consulting projected capacity market savings of $841 million across New York State over the study period. Although the PA Consulting model results identify substantial capacity market savings estimates, the report also notes that the model does not account for market responses. That is, to the extent generators displaced by the addition of new low cost entry can no longer operate economically, the model does not account for potential generator mothballing or retirements, which would affect capacity market prices. In other words, the model assumes the benefits of lower cost capacity from the new repowered units persist throughout the study period without inducing any market response. The PA Consulting study also does not account for the potential application of bid mitigation, which would eliminate any capacity market price reductions that the Repowering Options might otherwise produce. Given these limits in the modeling of ICAP, estimates of ICAP market impacts do not provide a sufficient or reliable basis to support generation investment decisions.[18]

d. Evaluating Supply Cost Considerations

To better understand the effects of the Repowering Proposals, National Grid retained Michael Cadwalader of Atlantic Economics LLC. Mr. Cadwalader's evaluation, provided as Exhibit 7, describes economic principles involved in assessing whether new

[17] The increase in state-wide energy costs under Repowering Option 2 is the result of projected price decreases from 2015 – 2019, followed by price increases in 2020 and beyond.

[18] The LEG study projected average annual capacity market savings of $159 million/year and $1.6 billion over 10 years across New York State. In addition to failing to account for market response or potential bid mitigation, the LEG study does not account for the new capacity zone being established in the State.

generation is economically efficient and would benefit electricity consumers in New York State. Mr. Cadwalader explains that the question of whether new generation is in the interest of customers must account for longer-term market responses and not be based just on short-term impacts of new entry on energy or capacity prices. This is particularly true when considering that customers would be bearing the direct costs of adding such generation in the form of long-term out-of-market contracts.

As explained in Mr. Cadwalader's affidavit, generator production cost estimates are preferred to projections of wholesale energy or capacity market effects for assessing the economic efficiency of a proposed generation project. Wholesale energy and capacity market price reductions represent transfer payments among market participants, and results in these markets are significantly influenced by assumptions relating to competitive responses to price changes. For example, generator retirements precipitated by new entry would affect market performance as would assumptions about interregional transactions. It is unlikely that entry of new generation capacity would have a significant and persistent effect on market prices without inducing some sort of market response. Neither LEG nor PA Consulting made any assumptions about subsequent generator retirements or other adverse market effects precipitated by new entry.

Mr. Cadwalader also notes that the entry of new subsidized generation can undermine the operation of competitive electricity markets and have harmful long-run effects on customers. Subsidized generation has the potential to chill entry of otherwise economically efficient generation, resulting in customers paying higher prices. Subsidizing generation through customer funded out-of-market payments also shifts the risk of generation investment decisions away from investors in the competitive market and to customers.[19] Mr. Cadwalader also explains that subsidized generation entry could trigger market mitigation rules that could result in the new generation not even having short-term beneficial effects on the capacity markets.[20]

In his analysis, Mr. Cadwalader ignored the potential mitigation rules and long-run capacity market responses, and instead assessed whether Repowering Option 1 or Option 2 produced economic benefits and should be pursued for the benefit of customers based solely on the effect on New York State generation production costs, estimated capacity revenues, the costs of the out-of-market support payments, and the avoided costs of the Transmission Upgrades. Based on that analysis, Mr. Cadwalader concluded that over the period 2015 – 2025, Repowering Option 1 had an expected net present value ("NPV") of -\$418 million, and Repowering Option 2 had an expected NPV of -\$470

[19] Shifting the risk of investment decisions away from regulated customers and to the competitive market was one of the objectives of the transition to competition in electric service. *See, e.g.,* Case 94-E-0952 *et al.,* In the Matter of Competitive Opportunities Regarding Electric Service, Opinion 96-12 (issued and effective May 20, 1996), pp. 30-31 (under competition, "[c]ompetitive providers (generators and energy service companies) would bear more of the risk of investment decisions, and customers less, than under regulation").

[20] As indicated in n. 11, *supra*, IPPNY has filed a complaint at FERC seeking to impose market mitigation at Dunkirk relating to the RSS agreements between Dunkirk and National Grid. It is very likely that similar arguments would be raised in the context of capacity bids from repowered Dunkirk units operating pursuant to an out-of-market support contract.

million. Tables 4 and 5 summarize those net benefits calculations, the details of which are described in Exhibit 7.

Table 4. Net Benefits Summary of Option 1

(a) NPV of Capacity Revenue	[redacted]
(b) NPV of Impact on Production Cost	($122 M) (increase)
(c) Net Benefits of Option 1 (a) + (b)	[redacted]
(d) NPV of avoided Transmission Alternative cost	[redacted]
(e) Subtotal of Benefits	[redacted]
(f) NPV of Payments to NRG	[redacted]
NPV of Expected Gain / Loss for Customers (e) – (f)	($418 M) Loss to Customers

Table 5. Net Benefits Summary of Option 2

(a) NPV of Capacity Revenue	[redacted]
(b) NPV of Impact on Production Cost	($430 M) (increase)
(c) Net Benefits of Option 1 (a) + (b)	[redacted]
(d) NPV of Transmission Alternative	[redacted]
(e) Subtotal of Benefits	[redacted]
(f)NPV of Payments to NRG	[redacted]
NPV of Expected Gain / Loss for Customers (e) – (f)	($470 M) Loss to Customers

Given these negative NPVs, Mr. Cadwalader recommends against pursuing either Repowering Option.

D. Regional Economic Effects

In addition to the primary considerations of reliability and costs to customers, the Repowering Order directed National Grid to consider other potential economic impacts of the Repowering Options. As mentioned previously, LEG provided projections on the non-electric customer economic impacts of Repowering Option 1. The LEG study found that Repowering Option 1 resulted in creation of 3000-3500 jobs over 10 years, primarily due to projected reductions in electricity costs. However, as mentioned previously, the LEG study did not account for any of the costs of the out-of-market support agreements.

Further, the LEG study also assumed that the projected electricity market impacts from Repowering Option 1 persisted throughout the study period and were not affected by any market responses during that time.

National Grid compared the economic impact of the repowering and transmission solutions using REMI,[21] a regional economic and demographic model that can measure the total economic costs and benefits of such projects. REMI is used extensively in planning and decision making studies, with over 150 US and international clients, including energy consultants; federal, regional, state and local government planning agencies; universities; non-profit institutions; and utilities. LEG used a 23-sector, three-region version of REMI for the State of New York to do an economic impact analysis for Repowering Option 1.[22] National Grid used a 169-sector, 45 region version of the REMI model for New York to do an economic impact analysis for all three solutions, Repowering Options 1 and 2, and the Transmission Upgrades.

The REMI model is a complete representation of the macroeconomic structure of the New York, Niagara Mohawk and Dunkirk area regional economies. By entering assumptions about the amount and timing of the proposed investments, anticipated rate impacts and wholesale electric cost changes, REMI provides projections of the economic impact of each project on State and local economic activity. Different assumptions will lead to different results but REMI provides a consistent method for comparing the economic impact of all planning assumptions under consideration.

1. Impacts Considered

For each reliability solution, National Grid considered the economic impact of (1) investment spending during construction; (2) annual O&M spending after project completion; and (3) anticipated rate impacts after the project is placed into service. The economic impact for each item includes the direct, indirect and induced impact on the local, regional and state economies. Direct impacts are those tied directly to the project, for example, the number of contractors hired to build a plant or for reconductoring a transmission line. Indirect impacts are those felt in the project's supply chain, that is, industries providing goods and services for the project. Induced impacts result from the spending of the direct and indirect workers and are felt mainly in the service sector, for example, increased retail activity and hiring.

2. Value of Maintaining Reliability

The REMI analysis did not include the economic benefits of maintaining reliability, which is the objective of all three solutions. Benefits of maintaining reliability include avoided job losses and other negative economic impacts that would result from load shedding and the inability to accommodate economic growth. These economic losses would be greater than the impacts resulting from the cost of maintaining reliability

[21] REMI is owned by Regional Economic Models, Incorporated and leased to its clients. More information about the REMI model can be found at www.remi.com.

[22] "NRG Dunkirk Repowering Project: Economic Impact Analysis," from website www.powerupny.com.

under any of the three solutions. For example, just the inability to accommodate economic growth between 2015 and 2025 would cost the Dunkirk area (Zone A) over 100,000 jobs, based on REMI's baseline forecast for the region. In addition, load shedding would be very costly to businesses and consumers, including the cost of lost output and sales, idled labor, spoiled goods, ruined production lines, damaged equipment and backup generator costs. These costs reduce regional competitiveness, spending and hiring, resulting in job and income losses. Since all three options are expected to meet reliability requirements equally well, the reliability benefits are the same across all three options and are not compared.

3. Wholesale Electricity Market Impacts

Although PA Consulting and LEG[23] both estimated reductions in market prices for energy and capacity in some years of the Study period for both Repowering Options 1 and 2, these savings did not take into account the impact of displaced generation on energy and capacity prices. Mr. Cadwalader explains in his affidavit that this could offset the positive impact of new generation on prices. Moreover, Mr. Cadwalader points out that entry of an uneconomic generator into the market, through out-of-market contracts, can discourage economically efficient generators from entering and cause consumers to be worse off as a result of paying above-market prices for services they could have purchased at market. Therefore, in the REMI analysis performed by the Company, we assumed no sustained market price impacts from adding new generation under Repowering Options 1 and 2. This approach balances the views of industry experts, some that believe market price impacts will be negative and some who believe they will be positive. This also allows a clearer comparison the economic costs of maintaining reliability under the three solutions.

4. Input Assumptions

Table 6 below summarizes REMI input assumptions for each reliability solution. Construction and O&M spending amounts for Repowering Options 1 and 2 were provided by NRG, except for property taxes, which National Grid estimated. Construction spending for Option 1 is assumed to take place from 2014 to 2017. The [redacted] spending amount represents just the in-state portion of the total investment planned by NRG. On-going O&M spending for Repowering Option 1, [redacted] per year, includes [redacted] permanent plant workers and approximately [redacted] million in annual property taxes from 2015-2025. NRG estimates construction spending for Repowering Option 2 will be [redacted] This is assumed to take place in 2014 and 2015. NRG predicts O&M spending of [redacted] per year for Option 2, [redacted] This includes [redacted] permanent plant workers, [redacted], and approximately [redacted] million in annual property taxes from 2015-2025. Construction spending for the Transmission Upgrades, $62 million, was estimated by National Grid and is expected to take place from 2013-2017. Associated O&M and property taxes for

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[23] In LEG's economic impact analysis, the overwhelming majority of jobs created and other economic benefits were due to LEG's projected sustained reductions in wholesale electricity costs under Repowering Option 1.

transmission investments of the amount involved here are estimated at approximately $2 million and $1.3 million annually, as shown in Exhibit 3. Derivation of the costs to customers of the different solutions is described in Section III.C.1 above.

Table 6. REMI Input Assumptions ($2012m)

	Repowering Option 1	**Repowering Option 2**	**Transmission Upgrades**
Construction Spending ($2012m)	[redacted]	[redacted]	$62
On-going O&M ($2012m)	[redacted] per year	[redacted] per year	$3 per year
Cost of Project to Customers ($m)	$64 per year	$33 per year	$10 per year

5. Summary of Results .

A summary of the REMI model economic impact results is shown in Exhibit 8. Construction spending has positive economic impacts in all three scenarios. Repowering Option 1 has the largest impact, creating 248 jobs per year from 2014 to 2017. This is because Option 1 involves the largest investment. The Transmission Upgrade is expected to create 156 jobs per year in New York during this period which is higher than the construction impact under Repowering Option 2, 132 jobs per year.

Repowering Options 1 and 2 both have permanent economic impacts due to the continued operation of the plants once they are in service. Planned O&M spending under Option 1 is expected to create 224 permanent jobs per year in New York over the 2015-2025 Study period, including direct, indirect and induced jobs. This is lower than the number of jobs estimated by LEG, primarily because LEG used a higher estimate of property taxes than National Grid. NRG expects annual O&M spending under Option 2 to be almost as high as Option 1, and that the refueled plant will employ 50 permanent workers, versus only 22 for Option 1. As a result, the total economic impact from operating the refueled plant under Option 2 is significantly greater than Option 1, 312 jobs per year over the 2015-2025 Study period.[24] On-going O&M spending for the Transmission Upgrades is modest compared to the Repowering Options and is expected create approximately 21 jobs per year in New York over the Study period.

The REMI analysis assumes that the cost of all three projects would be passed on to Niagara Mohawk rate payers.[25] These rate impacts reduce the purchasing power and

[24] It is unclear why NRG assumes the number of permanent workers at the plant under Repowering Option 2 would be more than twice the number than in Option 1, but that O&M spending would be lower. If the same assumptions regarding O&M for Option 1 were applied to Option 2, the overall Option 2 economic impact would be negative over the Study period for employment, GDP and income.

[25] As explained in Sections III.C.1 and III.F, the Company does not support allocation of the costs of the Repowering Options exclusively to Niagara Mohawk customers. For purposes of this evaluation only, the Company used a consistent cost allocation methodology for all three reliability solutions to aid comparison.

spending of local businesses and consumers; however, investment in a reliability solution is necessary to maintain area reliability and system security. As described in Section III.D.2, above, the positive economic impacts that result from investment to maintain reliability, accommodate growth and avoid costly outages far outweigh the economic effects of paying for that investment.

The rate impacts associated with Repowering Option 1 are the greatest, as are the associated economic costs. Rate impacts from Repowering Option 1 are expected to cost New York 503 jobs per year over the 2015-2025 period. Rate impacts associated with Option 2 are expected to reduce New York employment by 296 jobs per year. Rate impacts from the Transmission Upgrades are expected result in the reduction of 54 jobs per year in New York during the Study Period. The significant difference in results in electric cost-related job impacts between the LEG study and the Company's analysis again is due to the difference in market assumptions used by LEG (no changes in inter-regional market flows, no competitive response over the study period to changes in the market) and those used by the Company. Exhibit 8 provides additional information regarding the projected impact on jobs from the different solutions.

E. Emissions and Environmental Considerations

Like the reliability screen, each alternative also must satisfy applicable environmental standards and requirements. However, to the extent an alternative has other substantially beneficial environmental attributes, those attributes would also be factored in as secondary considerations in evaluating close alternatives.

The emission reductions (both water and air) described in NRG's proposal are compared to the historic baseline of the existing facility operating on coal. However, if the existing facility is retired as planned, future emissions would be zero. Therefore, the more appropriate evaluation is the comparison of emissions under the reference case with the Dunkirk plant retired, as was performed by PA Consulting.

1. Repowering Option 1

Based on results of the GE-MAPS model, Repowering Option 1 provides NOx and SO2 emissions reductions within Zone A as higher emitting, less efficient generation is displaced by the gas-fired combined cycle unit equipped with state of the art emission controls. NOx and SO2 emissions from this unit would be extremely low. However, the projected increase in CO2 emissions would result from increased utilization of this more efficient unit relative to the older units located within Zone A. This local increase of CO2 is negated when compared to the entire state, which results in a net reduction of all three pollutants statewide.

Repowering Option 1 also requires two Department of Public Service licensing proceedings, Article X for the construction of the unit and Article VII for the construction of the required gas pipeline extension. The schedules described in the NRG proposal are aggressive and further evaluation is needed to assess the reasonableness of the schedules and whether they could meet the reliability need dates.

2. Repowering Option 2

Repowering Option 2 provides a slight decrease of SO2 emissions locally, while NOx emissions are relatively unchanged. No additional emissions controls are being installed on the units; the reductions occur due to lower emitting characteristics of natural gas. Similar to Repowering Option 1, the CO2 emissions increase, again due to the expected increase in dispatch of this unit relative to higher emitting units in the region. Statewide emissions of NOx and SO2 decrease slightly while CO2 emissions increase nominally, since there is no efficiency benefit in this option.

Repowering Option 2 also requires an Article VII process for the construction of the required gas pipeline extension. As with Repowering Option 1, the schedules described in the proposal for Repowering Option 2 are aggressive and further evaluation is needed to assess the reasonableness of the schedules and whether they could meet the reliability need dates.

3. Transmission Upgrades

The Transmission Upgrades also will require an Article VII license. The environmental impacts are expected to be minimal as the Article VII project will be the re-conductoring of existing transmission lines in previously disturbed rights-of-way.

Based on the Company's analysis as summarized above, the relative emissions and environmental performance of Repowering Options 1 and 2 and the Transmission Upgrades do not provide a sufficient basis for differentiating among the alternatives.

F. Cost Allocation

NRG's Repowering Proposal presupposes that National Grid would be the counter-party to a contract for a Repowering project. As stated in this report, the Repowering Options provide substantially less net customer benefits relative to the Transmission Upgrades, and therefore are not in the best interests of customers or New York State. As described in Section III.C.1, for purposes of this report only, the Company determined the impact on delivery costs based on the recovery of the costs of the Repowering Options and the Transmission Upgrades from Niagara Mohawk customers using the cost allocation mechanism currently in effect for RSS costs. However, the use of this allocation methodology was solely for the purposes of providing a consistent basis for comparison and is not intended to reflect the Company's agreement to accept the cost and facilitate recovery of a Repowering Option contract on that basis. In addition, if cost allocation and recovery were evaluated over a different or broader base (*e.g.*, all New York electric customers), such cost recovery mechanism would change the cost per Niagara Mohawk customer presented above.

Although the results of the Company's analysis do not support the development of either of the Repowering Options, should the Commission direct the implementation of one of NRG's Repowering Options based on other public policy rationale, the costs of implementing such option that exceed the avoided cost of the Company's Transmission Upgrades should be allocated more broadly across the state.

IV. Recommendations

Repowering Options 1 and 2 and the Transmission Upgrades each satisfy the reliability need identified by the Company over the study period, and the relative reliability performance of the solutions does not provide a sufficient basis for differentiating among the alternatives on that basis.

The Transmission Upgrades produce the lowest cost to customers, approximately $10.5 million per year, or an NPV of $70.5 million over the study period. By comparison, Repowering Option 1 would have net costs of [redacted] in 2018, and an NPV over 10 years of $375 million.[26] Repowering Option 2 would have net costs of [redacted] in 2018, and an NPV over 10 years of $218 million.

With respect to the economic effect on electric customers of the different solutions, Mr. Cadwalader's affidavit describes the basis for determining whether investment in new generation will produce net benefits or net costs. Changes in generation production costs are the principal measure of determining whether new generation entry is economically efficient. Factors such as projected changes in wholesale energy markets and capacity markets do not themselves reflect improved economic efficiency, but rather represent transfer payments among market participants. Further, because the market forecasts by LEG and PA Consulting do not model the effect of competitive market responses, they do not accurately capture anticipated behavior and are inherently limited and unreliable for predicting long-term ICAP market results.

Using the impact on generation production costs, costs of the solution, estimated revenues, and the costs of the avoided Transmission Upgrades, Mr. Cadwalader estimated the 10-year NPV net benefit to customers of Repowering Option 1 to be -$418 million. The negative NPV represents additional costs to customers compared to a base case with the Transmission Upgrades. Similarly, Mr. Cadwalader determined the 10-year NPV customer benefit of Repowering Option 2 to be -$470 million compared to the base case. In each of these cases, Mr. Cadwalader did not factor in potential capacity mitigation or unit capacity factors below what is projected.

The Company's evaluation of regional economic effects indicates construction spending under each of the options has temporary positive economic impacts, and on-going O&M spending under the Repowering Options create considerably more jobs than O&M expenditures associated with the Transmission Upgrades. However, impacts on

[26] Net costs for the Repowering Options assumes the generators will achieve their projected capacity factor and no market mitigation rules are applied that restrict participation in the competitive market. To the extent revenues are reduced for whatever reason, net costs would increase.

electric rates also have a significant effect on jobs over the study period. Repowering Option 1 creates the most jobs during the construction phase when compared to Repowering Option 2 and the Transmission Upgrades (which have roughly comparable construction-related job creation); however, the costs and resulting rate impacts of Repowering Option 1 would result in the highest number of job losses during the study period. Job impacts from Repowering Option 2 and the Transmission Upgrades during the study period are close, with Repowering Option 2 projected to increase jobs slightly (due to relatively high O&M spending), while the Transmission Upgrades would result in a small number of job losses. In any case, however, any negative job impacts calculated by the economic models are far less than the adverse economic results that could occur from reliability problems related to insufficient investment.

Regarding environmental effects, the Company's analysis suggests there is insufficient basis for differentiating among Repowering Options 1 and 2 and the Transmission Upgrades on the basis of environmental performance.

Based on the analysis summarized in this report, the Company recommends the Commission support the Transmission Upgrades to address the reliability needs at the lowest overall cost, least risk to customers, and with minimum impact on competitive markets. The regulated nature of the Transmission Upgrades also provides for greater transparency of and scrutiny over the investments that are being made for the benefit of customers. Such transparency and oversight assures that customers pay no more than what is just and reasonable for reliable electric service.

Exhibit 1

REDACTED DOCUMENT

Dunkirk Repowering Option Summary

0.0736 Rate

	10 Year Study Period June 2015 to May 2025				Total Life of Proposals				
	Total Cost	Total Revenue	Net Cost	2013 NPV Net Cost	Proposal Life (yrs)	Total Cost	Total Revenue	Net Cost	2013 NPV Net Cost
Option #1 CCGT & Refuel Dunkirk #2	[redacted]	[redacted]	[redacted]	$375,037,093	[redacted]	[redacted]	[redacted]	[redacted]	$724,420,367
Option #2 Refuel Dunkirk #2,3,4	[redacted]	[redacted]	[redacted]	$217,568,828	[redacted]	[redacted]	[redacted]	[redacted]	$217,568,828

2018 Customer Impacts	Total Cost	Total Revenue	Annual Net Cost
Option #1 CCGT & Refuel Dunkirk #2	[redacted]	[redacted]	[redacted]
Option #2 Refuel Dunkirk #2,3,4	[redacted]	[redacted]	[redacted]

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Exhibit 2

REDACTED DOCUMENT

Summary of Dunkirk Repowering Options

[redacted]

REDACTED DOCUMENT

Model Inputs

			Option #1		Option #2		
	Description		NRG Proposal	NG Estimate	NRG Proposal	NG Estimate	Comments
1	CCGT Size	MW	422				
2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
23							
24							
25	[redacted]	[redacted]		[redacted]		[redacted]	[redacted]
[redacted]	[redacted]	[redacted]		[redacted]		[redacted]	[redacted]
28							
29							
30	**Environmental Data**						
31	[redacted]	[redacted]	[redacted]	[redacted]			[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]			[redacted]
40							
41							
42	**Miscellaneous**						
43	Annual Discount Factor for NPV			7.36%			CARIS Study 7.36

Exhibit 3

REDACTED DOCUMENT

Niagara Mohawk Power Corporation - Electric

Annual Carrying Charge
For use by Electric T&D Operations
As an Indicative Revenue Requirement
For Dunkirk Capital Project (Mid Range)
(000)

Estimated Capital Investment of Dunkirk Project:	
Reconductoring of 1 mile of the Niagara-Gardenville #180 line	$4,000
Reconductoring of 14 miles of the Packard-Erie #181 line	$37,100
Two 33.3 MVAr cap banks at Dunkirk (115 kV)	$2,500
One 75 MVAr cap bank at Huntley (115kV)	$1,400
Reconductor two 115 kV lines (5-Mile Rd to Homer Hill)	$18,000
Total Capital Investment	$63,000
First Year Average Rate Base	$62,354
Total Carrying Charge Applied to Average Rate Base - Return on Ratebase*	9.44%
Total Carrying Charge Applied to Initial Capital Investment - Deprec, RE Tax and O&M	7.32%
Estimated First Year Revenue Requirement	$10,498

* Carrying Charges per NMPC Case 12-E-0201

Per Electric & Gas 2012 Case for FY2014 - JP Appendix1, Sch 1, Pg 5 for COC & Final Revenue Req't for Depreciation, Property Taxes and O&M Expense

Capital Costs:	Amount	Ratio	Rate	Weighted Rate	Pretax Cost of Money	
Long Term Debt	$2,582,209	49.71%	4.04%	2.01%	2.01%	This section checks
Notes Payable	$52,399	1.01%	0.46%	0.00%	0.00%	
Customer Deposits	$37,559	0.72%	1.65%	0.01%	0.01%	
Preferred Stock (COP)	$28,985	0.56%	3.66%	0.02%	0.03%	calculations. The sum of the After tax cost of
Common Equity (COC)	$2,493,371	48.00%	9.30%	4.46%	7.39%	money plus the Federal and State tax
Total	$5,194,523	100.00%		6.50%	9.44%	add-ons should = the pre-tax cost of money
					9.44%	as calculated here.
					0.00%	

Income Taxes:	Rate	Formula		
Federal (FIT)	35%	(COP + COC + SIT)*(1/(1-35%)-.35) = FIT	2.60%	
State (SIT)	7.1%	(COP + COC)*(1/(1-7.1%)-1) = SIT	0.34%	

Check:

7.42%	pretax COP + COC
0.53%	SIT on pretax COP+COC
6.89%	less SIT
2.41%	FIT
4.48%	weighted COP + COC

	Expense	Average Depreciable Total Elec Plant in Svc	
Transmission Depreciation Expense			2.05%
Property Taxes (000)	$167,115.000	$7,935,898.434	2.11%

	Expense	Average Depreciable Trans. Plant in Svc.	
Trans. O & M Expense (000)	$71,292.715	$2,258,993.667	3.16%
Total Carrying Charge			16.76%

Note: Deferred tax impact is not included in this analysis.
O&M Expense relates to on-going O&M required, not including the initial O&M associated with constructing this facility

REDACTED DOCUMENT

Niagara Mohawk Power Corporation - Electric

Annual Carrying Charge
For use by Electric T&D Operations
As an Indicative Revenue Requirement
For Dunkirk Capital Project (Mid-Range)
(000)

Depreciation rate	2 05%
Return components	9 44%
Property Tax	2 11%
O&M rate	3 16%
O&M inflation rate	2 20%
Pre-Tax WACC	9 44%
Discount rate	7 36%

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20
Initial Investment	63,000	63,000	63,000	63,000	63,000	63,000	63,000	63,000	63,000	63,000	63,000	63,000	63,000	63,000	63,000	63,000	63,000	63,000	63,000	63,000
Deprec	1,292	1,292	1,292	1,292	1,292	1,292	1,292	1,292	1,292	1,292	1,292	1,292	1,292	1,292	1,292	1,292	1,292	1,292	1,292	1,292
Accum Reserve	1,292	2,583	3,875	5,166	6,458	7,749	9,041	10,332	11,624	12,915	14,207	15,498	16,790	18,081	19,373	20,664	21,956	23,247	24,539	25,830
NBV	61,709	60,417	59,126	57,834	56,543	55,251	53,960	52,668	51,377	50,085	48,794	47,502	46,211	44,919	43,628	42,336	41,045	39,753	38,462	37,170
Rev Req't - Return	5,886	5,764	5,642	5,520	5,399	5,277	5,155	5,033	4,911	4,789	4,667	4,545	4,423	4,301	4,179	4,057	3,936	3,814	3,692	3,570
Depreciation	1,292	1,292	1,292	1,292	1,292	1,292	1,292	1,292	1,292	1,292	1,292	1,292	1,292	1,292	1,292	1,292	1,292	1,292	1,292	1,292
Property Tax	1,329	1,329	1,329	1,329	1,329	1,329	1,329	1,329	1,329	1,329	1,329	1,329	1,329	1,329	1,329	1,329	1,329	1,329	1,329	1,329
O&M	1,991	2,035	2,079	2,125	2,172	2,220	2,268	2,318	2,369	2,422	2,475	2,529	2,585	2,642	2,700	2,759	2,820	2,882	2,945	3,010
Rev Req't - Expense	4,612	4,655	4,700	4,746	4,793	4,840	4,889	4,939	4,990	5,042	5,096	5,150	5,206	5,263	5,321	5,380	5,441	5,503	5,566	5,631
Total Rev Req't	10,498	10,420	10,343	10,266	10,191	10,117	10,044	9,972	9,901	9,831	9,763	9,695	9,629	9,564	9,500	9,438	9,376	9,316	9,258	9,201

Total 10 Years	101,583
10 Year NPV @ 7 36 %	70,473
Total 20 Years	196,323

REDACTED DOCUMENT

Niagara Mohawk Power Corporation - Electric

Annual Carrying Charge
For use by Electric T&D Operations
As an Indicative Revenue Requirement
For Dunkirk Capital Project (High Range)
(000)

Estimated Capital Investment of Dunkirk Project:	Add-on %	
Reconductoring of 1 mile of the Niagara-Gardenville #180 line	200.00%	$12,000
Reconductoring of 14 miles of the Packard-Erie #181 line	200.00%	$111,300
Two 33.3 MVAr cap banks at Dunkirk (115 kV)	50.00%	$3,750
One 75 MVAr cap bank at Huntley (115kV)	50.00%	$2,100
Reconductor two 115 kV lines (5-Mile Rd to Homer Hill)	50.00%	$27,000
Total Capital Investment		$156,150
First Year Average Rate Base		$154,549
Total Carrying Charge Applied to Average Rate Base - Return on Ratebase*		9.44%
Total Carrying Charge Applied to Initial Capital Investment - Deprec, RE Tax and O&M		7.32%
Estimated First Year Revenue Requirement		$26,020

* Carrying Charges per NMPC Case 12-E-0201

Per Electric & Gas 2012 Case for FY2014 - JP Appendix1, Sch 1, Pg 5 for COC & Final Revenue Req't for Depreciation, Property Taxes and O&M Expense

Capital Costs:	Amount	Ratio	Rate	Weighted Rate	Pretax Cost of Money	
Long Term Debt	$2,582,209	49.71%	4.04%	2.01%	2.01%	This section checks
Notes Payable	$52,399	1.01%	0.46%	0.00%	0.00%	
Customer Deposits	$37,559	0.72%	1.65%	0.01%	0.01%	
Preferred Stock (COP)	$28,985	0.56%	3.66%	0.02%	0.03%	calculations. The sum of the After tax cost of
Common Equity (COC)	$2,493,371	48.00%	9.30%	4.46%	7.39%	money plus the Federal and State tax
Total	$5,194,523	100.00%		6.50%	9.44%	add-ons should = the pre-tax cost of money
					9.44%	as calculated here.
					0.00%	

Income Taxes:	Rate	Formula			
Federal (FIT)	35%	(COP + COC + SIT)*(1/(1-35%)-.35) = FIT	2.60%		
				Check:	
State (SIT)	7.1%	(COP + COC)*(1/(1-7.1%)-1) = SIT	0.34%	7.42%	pretax COP + COC
				0.53%	SIT on pretax COP+COC
				6.89%	less SIT
Transmission Depreciation Expense			2.05%	2.41%	FIT
				4.48%	weighted COP + COC

	Expense	Average Depreciable Total Elec Plant in Svc	
Property Taxes (000)	$167,115.000	$7,935,898.434	2.11%

	Expense	Average Depreciable Trans. Plant in Svc.	
Trans. O & M Expense (000)	$71,292.715	$2,258,993.667	3.16%
Total Carrying Charge			16.76%

Note: Deferred tax impact is not included in this analysis.
O&M Expense relates to on-going O&M required, not including the initial O&M associated with constructing this facility

REDACTED DOCUMENT

Niagara Mohawk Power Corporation - Electric

Annual Carrying Charge
For use by Electric T&D Operations
As an Indicative Revenue Requirement
For Dunkirk Capital Project (High-Range)
(000)

Depreciation rate	2 05%
Return components	9 44%
Property Tax	2 11%
O&M rate	3 16%
O&M inflation rate	2 20%
Pre-Tax WACC	9 44%
Discount rate	7 36%

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
Initial Investment	156,150	156,150	156,150	156,150	156,150	156,150	156,150	156,150	156,150	156,150
Deprec	3,201	3,201	3,201	3,201	3,201	3,201	3,201	3,201	3,201	3,201
Accum Reserve	3,201	6,402	9,603	12,804	16,005	19,206	22,408	25,609	28,810	32,011
NBV	152,949	149,748	146,547	143,346	140,145	136,944	133,742	130,541	127,340	124,139
Rev Req't - Return	14,589	14,287	13,985	13,683	13,381	13,079	12,776	12,474	12,172	11,870
Depreciation	3,201	3,201	3,201	3,201	3,201	3,201	3,201	3,201	3,201	3,201
Property Tax	3,295	3,295	3,295	3,295	3,295	3,295	3,295	3,295	3,295	3,295
O&M	4,934	5,043	5,154	5,267	5,383	5,502	5,623	5,746	5,873	6,002
Rev Req't - Expense	11,430	11,539	11,650	11,763	11,879	11,997	12,118	12,242	12,369	12,498
Total Rev Req't	26,020	25,826	25,635	25,446	25,260	25,076	24,895	24,716	24,541	24,368

	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20
Initial Investment	156,150	156,150	156,150	156,150	156,150	156,150	156,150	156,150	156,150	156,150
Deprec	3,201	3,201	3,201	3,201	3,201	3,201	3,201	3,201	3,201	3,201
Accum Reserve	35,212	38,413	41,614	44,815	48,016	51,217	54,418	57,619	60,820	64,022
NBV	120,938	117,737	114,536	111,335	108,134	104,933	101,732	98,531	95,330	92,129
Rev Req't - Return	11,568	11,265	10,963	10,661	10,359	10,057	9,755	9,452	9,150	8,848
Depreciation	3,201	3,201	3,201	3,201	3,201	3,201	3,201	3,201	3,201	3,201
Property Tax	3,295	3,295	3,295	3,295	3,295	3,295	3,295	3,295	3,295	3,295
O&M	6,134	6,269	6,407	6,548	6,692	6,839	6,989	7,143	7,300	7,461
Rev Req't - Expense	12,630	12,765	12,903	13,044	13,188	13,335	13,485	13,639	13,796	13,957
Total Rev Req't	24,197	24,030	23,866	23,705	23,547	23,392	23,240	23,091	22,946	22,805

Total 10 Years	251,781
10 Year NPV @ 7 36 %	174,673
Total 20 Years	486,600

Exhibit 4

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID
ALLOCATION OF ESTIMATED RELIABILITY SUPPORT SERVICES COSTS
ANNUAL NET COSTS - REPOWERING OPTION 1

	Design Service Class	12-months ended 3-31-2016 kW Billed (A)	12-months ended 3-31-2016 kWh Sales (B)	Transmission Plant Allocator (C)	Allocation of Estimated RSS Costs (D)	2018 Surcharge Rate (E)	2019	2020	2021	2022	2023	2024	2025	2026	2027
1	SC1	-	11,148,494,696	42 67%	$32,382,311	$ 0 00290	$ 0 00301	$ 0 00306	$ 0 00310	$ 0 00314	$ 0 00318	$ 0 00322	$ 0 00288	$ 0 00392	$ 0 00396
2	SC1C	-	357,847,234	1 00%	$758,901	$ 0 00212	$ 0 00220	$ 0 00223	$ 0 00227	$ 0 00230	$ 0 00232	$ 0 00235	$ 0 00210	$ 0 00286	$ 0 00289
3	SC2ND	-	653,354,732	2 68%	$2,033,855	$ 0 00311	$ 0 00323	$ 0 00328	$ 0 00333	$ 0 00337	$ 0 00341	$ 0 00345	$ 0 00309	$ 0 00420	$ 0 00425
4	SC2D	15,110,754		14 55%	$11,042,011	$ 0 73	$ 0 76	$ 0 77	$ 0 78	$ 0 79	$ 0 80	$ 0 81	$ 0 72	$ 0 98	$ 1 00
	SC3														
5	Secondary	10,832,314		13 04%	$9,896,071	$ 0 91	$ 0 95	$ 0 96	$ 0 98	$ 0 99	$ 1 00	$ 1 01	$ 0 91	$ 1 23	$ 1 25
6	Primary	4,487,194		5.10%	$3,870,396	$ 0 86	$ 0 89	$ 0 91	$ 0 92	$ 0 93	$ 0 94	$ 0 96	$ 0 86	$ 1 16	$ 1 18
7	Transmission	1,555,433		1 30%	$986,571	$ 0 63	$ 0 66	$ 0 67	$ 0 68	$ 0 69	$ 0 69	$ 0 70	$ 0 63	$ 0 85	$ 0 87
8	Total	16,874,941	-	19.44%	$14,753,038										
	SC3A														
9	Secondary														
10	Primary	2,684,371		3.19%	$2,420,895	$ 0 90	$ 0 93	$ 0 95	$ 0 96	$ 0 98	$ 0 99	$ 1 00	$ 0 89	$ 1 22	$ 1 23
11	Subtransmission	3,704,085		4 06%	$3,081,139	$ 0 83	$ 0 86	$ 0 88	$ 0 89	$ 0 90	$ 0 91	$ 0 92	$ 0 83	$ 1 12	$ 1 13
12	Transmission	12,715,606		12 39%	$9,402,785	$ 0 74	$ 0 77	$ 0 78	$ 0 79	$ 0 80	$ 0 81	$ 0 82	$ 0 73	$ 1 00	$ 1 01
13	Total	19,104,062	-	19 64%	$14,904,818										
14	Total PSC 220				$75,874,935										
	Street and Highway Lighting														
15	SC1	-	23,665,889		$1,768	$ 0 00007	$ 0 00008	$ 0 00008	$ 0 00008	$ 0 00008	$ 0 00008	$ 0 00008	$ 0 00007	$ 0 00010	$ 0 00010
16	SC2/5	-	159,398,607		$11,907	$ 0 00007	$ 0 00008	$ 0 00008	$ 0 00008	$ 0 00008	$ 0 00008	$ 0 00008	$ 0 00007	$ 0 00010	$ 0 00010
17	SC3/6	-	9,219,028		$689	$ 0 00007	$ 0 00008	$ 0 00008	$ 0 00008	$ 0 00008	$ 0 00008	$ 0 00008	$ 0 00007	$ 0 00010	$ 0 00010
18	SC4	-	10,911,329		$815	$ 0 00007	$ 0 00008	$ 0 00008	$ 0 00008	$ 0 00008	$ 0 00008	$ 0 00008	$ 0 00007	$ 0 00010	$ 0 00010
19	Total PSC 214	-	203,194,853	0 02%	$15,178		$ 15,733	$ 15,982	$ 16,213	$ 16,425	$ 16,624	$ 16,820	$ 15,058	$ 20,459	$ 20,707
20	Total PSC 220/214			100 00%	$75,890,113		$ 78,664,594	$ 79,912,039	$ 81,065,014	$ 82,127,125	$ 83,119,083	$ 84,098,058	$ 75,289,067	$ 102,294,720	$ 103,533,960

A Joint Proposal, Appendix 2, Schedule 6, Column A less EZR and Excelsior
B Joint Proposal, Appendix 2, Schedule 6, Column A less EZR and Excelsior
C Exhibt ____ (E-RDP-3), Schedule 3, Page 1 of 8, Line 17
D RSS costs allocated by Column C
E Column (D) / Column (A) or Column (B)

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID
ALLOCATION OF ESTIMATED RELIABILITY SUPPORT SERVICES COSTS
ANNUAL NET COSTS - REPOWERING OPTION 2

	Design Service Class	12-months ended 3-31-2016 kW Billed (A)	12-months ended 3-31-2016 kWh Sales (B)	Transmission Plant Allocator (C)	Allocation of Estimated RSS Costs (D)	2018 Surcharge Rate (E)	2019	2020	2021	2022	2023	2024	2025
1	SC1	-	11,148,494,696	42 67%	$14,858,100	$ 0 00133	$ 0 00137	$ 0 00140	$ 0 00144	$ 0 00147	$ 0 00151	$ 0 00155	$ 0 00066
2	SC1C	-	357,847,234	1 00%	$348,210	$ 0 00097	$ 0 00100	$ 0 00102	$ 0 00105	$ 0 00107	$ 0 00110	$ 0 00113	$ 0 00048
3	SC2ND	-	653,354,732	2 68%	$933,202	$ 0 00143	$ 0 00146	$ 0 00150	$ 0 00154	$ 0 00158	$ 0 00162	$ 0 00166	$ 0 00071
4	SC2D	15,110,754		14 55%	$5,066,449	$ 0 34	$ 0 34	$ 0 35	$ 0 36	$ 0 37	$ 0 38	$ 0 39	$ 0 17
	SC3												
5	Secondary	10,832,314		13 04%	$4,540,652	$ 0 42	$ 0 43	$ 0 44	$ 0 45	$ 0 46	$ 0 47	$ 0 49	$ 0 21
6	Primary	4,487,194		5.10%	$1,775,869	$ 0 40	$ 0 41	$ 0 42	$ 0 43	$ 0 44	$ 0 45	$ 0 46	$ 0 20
7	Transmission	1,555,433		1 30%	$452,672	$ 0 29	$ 0 30	$ 0 31	$ 0 31	$ 0 32	$ 0 33	$ 0 34	$ 0 14
8	Total	16,874,941	-	19.44%	$6,769,193								
	SC3A												
9	Secondary												
10	Primary	2,684,371		3.19%	$1,110,788	$ 0 41	$ 0 42	$ 0 43	$ 0 45	$ 0 46	$ 0 47	$ 0 48	$ 0 20
11	Subtransmission	3,704,085		4 06%	$1,413,731	$ 0 38	$ 0 39	$ 0 40	$ 0 41	$ 0 42	$ 0 43	$ 0 44	$ 0 19
12	Transmission	12,715,606		12 39%	$4,314,316	$ 0 34	$ 0 35	$ 0 36	$ 0 37	$ 0 37	$ 0 38	$ 0 39	$ 0 17
13	Total	19,104,062	-	19 64%	$6,838,835								
14	Total PSC 220				$34,813,988								
	Street and Highway Lighting												
15	SC1	-	23,665,889		$811	$ 0 00003	$ 0 00004	$ 0 00004	$ 0 00004	$ 0 00004	$ 0 00004	$ 0 00004	$ 0 00002
16	SC2/5	-	159,398,607		$5,463	$ 0 00003	$ 0 00004	$ 0 00004	$ 0 00004	$ 0 00004	$ 0 00004	$ 0 00004	$ 0 00002
17	SC3/6	-	9,219,028		$316	$ 0 00003	$ 0 00004	$ 0 00004	$ 0 00004	$ 0 00004	$ 0 00004	$ 0 00004	$ 0 00002
18	SC4	-	10,911,329		$374	$ 0 00003	$ 0 00004	$ 0 00004	$ 0 00004	$ 0 00004	$ 0 00004	$ 0 00004	$ 0 00002
19	Total PSC 214	-	203,194,853	0 02%	$6,964		$ 7,138	$ 7,317	$ 7,500	$ 7,687	$ 7,879	$ 8,076	$ 3,449
20	Total PSC 220/214			100 00%	$34,820,952		$ 35,691,476	$ 36,583,763	$ 37,498,357	$ 38,435,816	$ 39,396,712	$ 40,381,629	$ 17,246,321

A Joint Proposal, Appendix 2, Schedule 6, Column A less EZR and Excelsior
B Joint Proposal, Appendix 2, Schedule 6, Column A less EZR and Excelsior
C Exhibit ____ (E-RDP-3), Schedule 3, Page 1 of 8, Line 17
D RSS costs allocated by Column C
E Column (D) / Column (A) or Column (B)

REDACTED DOCUMENT

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID
ALLOCATION OF ESTIMATED RELIABILITY SUPPORT SERVICES COSTS
ANNUAL NET COSTS - TRANSMISSION OPTION

	Design Service Class	12-months ended 3-31-2016 kW Billed (A)	12-months ended 3-31-2016 kWh Sales (B)	Transmission Plant Allocator (C)	Allocation of Estimated RSS Costs (D)	2018 Surcharge Rate (E)	2019	2020	2021	2022	2023	2024	2025	2026	2027
1	SC1	-	11,148,494,696	42 67%	$4,479,429	$ 0 00040	$ 0 00040	$ 0 00040	$ 0 00039	$ 0 00039	$ 0 00039	$ 0 00038	$ 0 00038	$ 0 00038	$ 0 00038
2	SC1C	-	357,847,234	1 00%	$104,978	$ 0 00029	$ 0 00029	$ 0 00029	$ 0 00029	$ 0 00028	$ 0 00028	$ 0 00028	$ 0 00028	$ 0 00028	$ 0 00027
3	SC2ND	-	653,354,732	2 68%	$281,342	$ 0 00043	$ 0 00043	$ 0 00042	$ 0 00042	$ 0 00042	$ 0 00041	$ 0 00041	$ 0 00041	$ 0 00041	$ 0 00040
4	SC2D	15,110,754		14 55%	$1,527,436	$ 0 10	$ 0 10	$ 0 10	$ 0 10	$ 0 10	$ 0 10	$ 0 10	$ 0 10	$ 0 10	$ 0 09
	SC3														
5	Secondary	10,832,314		13.04%	$1,368,918	$ 0 13	$ 0 13	$ 0 12	$ 0 12	$ 0 12	$ 0 12	$ 0 12	$ 0 12	$ 0 12	$ 0 12
6	Primary	4,487,194		5.10%	$535,390	$ 0 12	$ 0 12	$ 0 12	$ 0 12	$ 0 12	$ 0 11	$ 0 11	$ 0 11	$ 0 11	$ 0 11
7	Transmission	1,555,433		1.30%	$136,472	$ 0 09	$ 0 09	$ 0 09	$ 0 09	$ 0 09	$ 0 08	$ 0 08	$ 0 08	$ 0 08	$ 0 08
8	Total	16,874,941	-	19.44%	$2,040,780										
	SC3A														
9	Secondary														
10	Primary	2,684,371		3.19%	$334,881	$ 0 12	$ 0 12	$ 0 12	$ 0 12	$ 0 12	$ 0 12	$ 0 12	$ 0 12	$ 0 12	$ 0 12
11	Subtransmission	3,704,085		4.06%	$426,212	$ 0 12	$ 0 11	$ 0 11	$ 0 11	$ 0 11	$ 0 11	$ 0 11	$ 0 11	$ 0 11	$ 0 11
12	Transmission	12,715,606		12.39%	$1,300,683	$ 0 10	$ 0 10	$ 0 10	$ 0 10	$ 0 10	$ 0 10	$ 0 10	$ 0 10	$ 0 10	$ 0 10
13	Total	19,104,062	-	19.64%	$2,061,776										
14	Total PSC 220				$10,495,742										
	Street and Highway Lighting														
15	SC1	-	23,665,889		$245	$ 0 00001	$ 0 00001	$ 0 00001	$ 0 00001	$ 0 00001	$ 0 00001	$ 0 00001	$ 0 00001	$ 0 00001	$ 0 00001
16	SC2/5	-	159,398,607		$1,647	$ 0 00001	$ 0 00001	$ 0 00001	$ 0 00001	$ 0 00001	$ 0 00001	$ 0 00001	$ 0 00001	$ 0 00001	$ 0 00001
17	SC3/6	-	9,219,028		$95	$ 0 00001	$ 0 00001	$ 0 00001	$ 0 00001	$ 0 00001	$ 0 00001	$ 0 00001	$ 0 00001	$ 0 00001	$ 0 00001
18	SC4	-	10,911,329		$113	$ 0 00001	$ 0 00001	$ 0 00001	$ 0 00001	$ 0 00001	$ 0 00001	$ 0 00001	$ 0 00001	$ 0 00001	$ 0 00001
19	Total PSC 214	-	203,194,853	0 02%	$2,100		$ 2,084	$ 2,069	$ 2,053	$ 2,038	$ 2,023	$ 2,009	$ 1,994	$ 1,980	$ 1,966
20	Total PSC 220/214			100 00%	$10,497,841		$ 10,419,721	$ 10,342,565	$ 10,266,393	$ 10,191,228	$ 10,117,091	$ 10,044,005	$ 9,971,994	$ 9,901,081	$ 9,831,290

A Joint Proposal, Appendix 2, Schedule 6, Column A less EZR and Excelsior
B Joint Proposal, Appendix 2, Schedule 6, Column A less EZR and Excelsior
C Exhibt ____ (E-RDP-3), Schedule 3, Page 1 of 8, Line 17
D RSS costs allocated by Column C
E Column (D) / Column (A) or Column (B)

REDACTED DOCUMENT

REPOWERING OPTION 1
BILL IMPACTS

SC1

600 kWh		without RSS	with RSS									
		2018	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Customer Charge		$17.00	$17.00	$17.00	$17.00	$17.00	$17.00	$17.00	$17.00	$17.00	$17.00	$17.00
T&D Energy Charge	kWh x	$0.04758	$0.04758	$0.04758	$0.04758	$0.04758	$0.04758	$0.04758	$0.04758	$0.04758	$0.04758	$0.04758
Deferral Recovery	kWh x	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
RSS	kWh x	$0.00000	$0.00290	$0.00301	$0.00306	$0.00310	$0.00314	$0.00318	$0.00322	$0.00288	$0.00392	$0.00396
Legacy Transition Charge	kWh x	$0.00151	$0.00151	$0.00163	$0.00161	$0.00184	$0.00125	$0.00119	$0.00092	$0.00103	$0.00017	$0.00008
Electricity Supply Rate Mechanism	kWh x	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
Commodity Energy Charge	kWh x	$0.07266	$0.07266	$0.07552	$0.07677	$0.08051	$0.08333	$0.08624	$0.08926	$0.09239	$0.09562	$0.09897
Transmission Revenue Adjustment Charge	kWh x	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
Systems Benefits Charge	kWh x	$0.00551	$0.00551	$0.00551	$0.00551	$0.00551	$0.00551	$0.00551	$0.00551	$0.00551	$0.00551	$0.00551
Incremental State Assessment Surcharge	kWh x	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
Merchant Function Charge	kWh x	$0.00269	$0.00269	$0.00277	$0.00281	$0.00291	$0.00298	$0.00306	$0.00314	$0.00323	$0.00331	$0.00341
NYPA Hydro Benefit Reconcilation Charge	kWh x	($0.00220)	($0.00220)	($0.00227)	($0.00229)	($0.00235)	($0.00239)	($0.00244)	($0.00248)	($0.00253)	($0.00258)	($0.00263)
Gross Receipts Tax												
Commodity	Bill /	0.9900	0.9900	0 9900	0.9900	0.9900	0.9900	0.9900	0 9900	0.9900	0.9900	0.9900
Delivery	Bill /	0.9700	0.9700	0 9700	0.9700	0.9700	0.9700	0.9700	0 9700	0.9700	0.9700	0.9700
Delivery		$49.94	$51.73	$51.83	$51.84	$51.97	$51.60	$51.57	$51.39	$51.22	$51.30	$51 23
Commodity		$45.67	$45.67	$47.45	$48.23	$50.55	$52 31	$54.12	$56.00	$57.95	$59.96	$62.04
		$95.61	$97.41	$99.28	$100.07	$102.52	$103.91	$105.69	$107.39	$109.17	$111.26	$113.28
Delivery Bill Impact			3.60%	0.19%	0.01%	0.25%	-0.71%	-0.07%	-0.35%	-0.32%	0.15%	-0.12%
Total Bill Impact			1.88%	1.93%	0.79%	2.45%	1.35%	1.71%	1.61%	1.66%	1.91%	1.82%
Annual Delivery Bill Change			$ 21.56	$ 1.20	$ 0.08	$ 1.56	$ (4.41)	$ (0.44)	$ (2.15)	$ (1.99)	$ 0.91	$ (0.75)
Annual Commodity Bill Change			$ -	$ 21.33	$ 9.37	$ 27.89	$ 21.05	$ 21.78	$ 22.55	$ 23.34	$ 24.15	$ 25.00
Annual Total Bill Changes			$ 21.56	$ 22.53	$ 9.44	$ 29.44	$ 16.64	$ 21.35	$ 20.40	$ 21.35	$ 25.06	$ 24.25

MFC	
Uncollectible	2.340%
WC	0.363%
Credit and Collections	0.00063
Electric Supply Procurement	0.0001

REPOWERING OPTION 1
BILL IMPACTS

SC2ND

1500 kWh		without RSS	with RSS									
		2018	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Customer Charge		$21.02	$21.02	$21.02	$21.02	$21.02	$21.02	$21.02	$21.02	$21.02	$21.02	$21.02
T&D Energy Charge	kWh x	$0.05696	$0.05696	$0.05696	$0.05696	$0.05696	$0.05696	$0.05696	$0.05696	$0.05696	$0.05696	$0.05696
Deferral Recovery	kWh x	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
RSS	kWh x	$0.00000	$0.00311	$0.00323	$0.00328	$0.00333	$0.00337	$0.00341	$0.00345	$0.00309	$0.00420	$0.00425
Legacy Transition Charge	kWh x	$0.00151	$0.00151	$0.00163	$0.00161	$0.00184	$0.00125	$0.00119	$0.00092	$0.00103	$0.00017	$0.00008
Electricity Supply Rate Mechanism	kWh x	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
Commodity Energy Charge	kWh x	$0.07702	$0.07702	$0.08000	$0.08105	$0.08496	$0.08793	$0.09101	$0.09419	$0.09749	$0.10090	$0.10443
Transmission Revenue Adjustment Charge	kWh x	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
Systems Benefits Charge	kWh x	$0.00551	$0.00551	$0.00551	$0.00551	$0.00551	$0.00551	$0.00551	$0.00551	$0.00551	$0.00551	$0.00551
Incremental State Assessment Surcharge	kWh x	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
Merchant Function Charge	kWh x	$0.00281	$0.00281	$0.00289	$0.00292	$0.00303	$0.00311	$0.00319	$0.00328	$0.00337	$0.00346	$0.00355
Gross Receipts Tax												
Commodity	Bill /	0.9900	0.9900	0.9900	0.9900	0.9900	0.9900	0.9900	0.9900	0 9900	0.9900	0.9900
Delivery	Bill /	0.9900	0.9900	0.9900	0.9900	0.9900	0.9900	0.9900	0.9900	0 9900	0.9900	0.9900
Delivery		$ 118.17	$ 122.88	$ 123.24	$ 123.29	$ 123.71	$ 122.88	$ 122.86	$ 122.50	$ 122.13	$ 122.50	$ 122.44
Commodity		$ 120.95	$ 120.95	$ 125.60	$ 127.23	$ 133.31	$ 137.94	$ 142.73	$ 147.68	$ 152.81	$ 158.12	$ 163.62
		$ 239.12	$ 243.83	$ 248.85	$ 250.53	$ 257.02	$ 260.81	$ 265.59	$ 270.18	$ 274.94	$ 280.63	$ 286.05
Delivery Bill Impact			3.99%	0.29%	0.04%	0.33%	-0.67%	-0.01%	-0.29%	-0.30%	0.31%	-0.06%
Total Bill Impact			1.97%	2.06%	0.68%	2.59%	1.48%	1.83%	1.73%	1.76%	2.07%	1.93%
Annual Delivery Bill Change			$ 56.55	$ 4.35	$ 0.60	$ 4.94	$ (9.95)	$ (0.19)	$ (4.35)	$ (4.42)	$ 4.49	$ (0.82)
Annual Commodity Bill Change			$ -	$ 55.80	$ 19.55	$ 72.93	$ 55.53	$ 57.47	$ 59.48	$ 61.56	$ 63.72	$ 65.95
Annual Total Bill Changes			$ 56.55	$ 60.14	$ 20.16	$ 77.87	$ 45.58	$ 57.28	$ 55.13	$ 57.14	$ 68.20	$ 65.13

MFC	
Uncollectible	2.340%
WC	0.363%
Credit and Collections	0.0006
Electric Supply Procurement	0.0001

REDACTED DOCUMENT
REPOWERING OPTION 1
BILL IMPACTS

SC2D

			without RSS	with RSS									
7,200 kWh													
25 kW			2018	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Customer Charge			$52.52	$52 52	$52.52	$52.52	$52.52	$52.52	$52.52	$52.52	$52.52	$52.52	$52.52
T&D Demand Charge		kW x	$10.27	$10 27	$10.27	$10.27	$10.27	$10.27	$10.27	$10.27	$10.27	$10.27	$10.27
Deferral Recovery		kW x	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
RSS		kW x	$0.00	$0.73	$0.76	$0.77	$0.78	$0.79	$0.80	$0.81	$0.72	$0.98	$1.00
Legacy Transition Charge		kWh x	$0.00151	$0.00151	$0.00163	$0.00161	$0.00184	$0.00125	$0.00119	$0.00092	$0.00103	$0.00017	$0.00008
Commodity Energy Charge		kWh x	$0.07091	$0.07091	$0.07374	$0.07498	$0.07867	$0.08142	$0.08427	$0.08722	$0.09027	$0.09343	$0.09670
Transmission Revenue Adjustment Charge		kWh x	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
Systems Benefits Charge		kWh x	$0.00551	$0.00551	$0.00551	$0.00551	$0.00551	$0.00551	$0.00551	$0.00551	$0.00551	$0.00551	$0.00551
Incremental State Assessment Surcharge		kW x	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Merchant Function Charge		kWh x	$0.00062	$0.00062	$0.00064	$0.00065	$0.00067	$0.00069	$0.00071	$0.00073	$0.00075	$0.00077	$0.00079
Gross Receipts Tax													
Commodity		Bill /	0.9900	0.9900	0.9900	0 9900	0.9900	0.9900	0 9900	0.9900	0.9900	0 9900	0.9900
Delivery		Bill /	0.9900	0.9900	0.9900	0 9900	0.9900	0.9900	0 9900	0.9900	0.9900	0 9900	0.9900
Delivery			$ 363.44	$ 381.89	$ 383.46	$ 383.63	$ 385.54	$ 381.50	$ 381 37	$ 379.58	$ 378.30	$ 378.60	$ 378.21
Commodity			$ 520.27	$ 520.27	$ 540.98	$ 550.05	$ 577.03	$ 597.18	$ 618.04	$ 639.63	$ 661.98	$ 685 11	$ 709.05
			$ 883.72	$ 902.17	$ 924.43	$ 933.68	$ 962.57	$ 978.69	$ 999.42	$ 1,019.21	$ 1,040.28	$ 1,063.71	$ 1,087.25
	Delivery Bill Impact			5.08%	0.41%	0.05%	0.50%	-1.05%	-0.03%	-0.47%	-0.34%	0.08%	-0.10%
	Total Bill Impact			2.09%	2.47%	1.00%	3.09%	1.67%	2.12%	1.98%	2.07%	2.25%	2.21%
	Annual Delivery Bill Change			$ 221.44	$ 18.77	$ 2.08	$ 22.94	$ (48.46)	$ (1.58)	$ (21.52)	$ (15.39)	$ 3.66	$ (4.74)
	Annual Commodity Bill Change			$ -	$ 248.41	$ 108.86	$ 323.74	$ 241.86	$ 250 33	$ 259.09	$ 268.16	$ 277 54	$ 287.26
	Annual Total Bill Changes			$ 221.44	$ 267.18	$ 110.94	$ 346.69	$ 193.40	$ 248.75	$ 237.56	$ 252.77	$ 281 21	$ 282.51

MFC	
Uncollectible	0.290%
WC	0.363%
Credit and Collections	0.00006
Electric Supply Procurement	0.0001

SC3 Primary

		without RSS	with RSS									
216,000 kWh												
500 kW		2018	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Customer Charge		$436 70	$436 70	$436 70	$436 70	$436 70	$436 70	$436 70	$436 70	$436 70	$436 70	$436 70
T&D Demand Charge	kW x	$8 15	$8 15	$8 15	$8 15	$8 15	$8 15	$8 15	$8 15	$8 15	$8 15	$8 15
Deferral Recovery	kW x	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00
RSS	kW x	$0 00	$0 86	$0 89	$0 91	$0 92	$0 93	$0 94	$0 96	$0 86	$1 16	$1 18
Legacy Transition Charge	kWh x	$0 00151	$0 00151	$0 00163	$0 00161	$0 00184	$0 00125	$0 00119	$0 00092	$0 00103	$0 00017	$0 00008
Commodity Energy Charge	kWh x	$0 06452	$0 06452	$0 06715	$0 06934	$0 07281	$0 07536	$0 07800	$0 08073	$0 08355	$0 08648	$0 08950
Transmission Revenue Adjustment Charge	kWh x	$0 00000	$0 00000	$0 00000	$0 00000	$0 00000	$0 00000	$0 00000	$0 00000	$0 00000	$0 00000	$0 00000
Systems Benefits Charge	kWh x	$0 00551	$0 00551	$0 00551	$0 00551	$0 00551	$0 00551	$0 00551	$0 00551	$0 00551	$0 00551	$0 00551
Incremental State Assessment Surcharge	kW x	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00
Merchant Function Charge	kWh x	$0 00058	$0 00058	$0 00060	$0 00061	$0 00064	$0 00065	$0 00067	$0 00069	$0 00071	$0 00072	$0 00074
Gross Receipts Tax												
Commodity	Bill /	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900
Delivery	Bill /	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900
Delivery		$ 6,088 70	$ 6,524 33	$ 6,566 93	$ 6,570 18	$ 6,625 75	$ 6,502 94	$ 6,497 45	$ 6,442 12	$ 6,417 34	$ 6,384 53	$ 6,370 74
Commodity		$ 14,203 71	$ 14,203 71	$ 14,780 98	$ 15,263 04	$ 16,024 66	$ 16,584 30	$ 17,163 53	$ 17,763 03	$ 18,383 52	$ 19,025 72	$ 19,690 40
		$ 20,292 41	$ 20,728 04	$ 21,347 91	$ 21,833 22	$ 22,650 41	$ 23,087 24	$ 23,660 98	$ 24,205 15	$ 24,800 86	$ 25,410 24	$ 26,061 14
Delivery Bill Impact			7 15%	0 65%	0 05%	0 85%	-1 85%	-0 08%	-0 85%	-0 38%	-0 51%	-0 22%
Total Bill Impact			2 15%	2 99%	2 27%	3 74%	1 93%	2 49%	2 30%	2 46%	2 46%	2 56%
Annual Delivery Bill Change			$ 5,227 53	$ 511 23	$ 39 05	$ 666 80	$ (1,473 71)	$ (65 87)	$ (663 99)	$ (297 31)	$ (393 82)	$ (165 38)
Annual Commodity Bill Change			$ -	$ 6,927 27	$ 5,784 71	$ 9,139 44	$ 6,715 70	$ 6,950 75	$ 7,194 02	$ 7,445 81	$ 7,706 42	$ 7,976 14
Annual Total Bill Changes			$ 5,227 53	$ 7,438 50	$ 5,823 76	$ 9,806 24	$ 5,241 98	$ 6,884 87	$ 6,530 03	$ 7,148 50	$ 7,312 60	$ 7,810 76

MFC	
Uncollectible	0 290%
WC	0 363%
Credit and Collections	0 00006
Electric Supply Procurei	0 0001

SC3A Transmission		without RSS	with RSS									
2,304,000 kWh		2018	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
4,000 kW												
Customer Charge		$3,500 00	$3,500 00	$3,500 00	$3,500 00	$3,500 00	$3,500 00	$3,500 00	$3,500 00	$3,500 00	$3,500 00	$3,500 00
T&D Demand Charge	kW x	$2 84	$2 84	$2 84	$2 84	$2 84	$2 84	$2 84	$2 84	$2 84	$2 84	$2 84
Deferral Recovery	kW x	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00
RSS	kW x	$0 00	$0 74	$0 77	$0 78	$0 79	$0 80	$0 81	$0 82	$0 73	$1 00	$1 01
Legacy Transition Charge	kWh x	$0 00151	$0 00151	$0 00163	$0 00161	$0 00184	$0 00125	$0 00119	$0 00092	$0 00103	$0 00017	$0 00008
Commodity Energy Charge	kWh x	$0 06047	$0 06047	$0 06297	$0 06465	$0 06791	$0 07028	$0 07274	$0 07529	$0 07793	$0 08065	$0 08348
Transmission Revenue Adjustment Charge	kWh x	$0 00000	$0 00000	$0 00000	$0 00000	$0 00000	$0 00000	$0 00000	$0 00000	$0 00000	$0 00000	$0 00000
Systems Benefits Charge	kWh x	$0 00551	$0 00551	$0 00551	$0 00551	$0 00551	$0 00551	$0 00551	$0 00551	$0 00551	$0 00551	$0 00551
Incremental State Assessment Surcharge	kW x	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00
Merchant Function Charge	kWh x	$0 00055	$0 00055	$0 00057	$0 00058	$0 00060	$0 00062	$0 00064	$0 00065	$0 00067	$0 00069	$0 00071
Gross Receipts Tax												
Commodity	Bill /	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900
Delivery	Bill /	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900
Delivery		$ 31,345	$ 34,333	$ 34,727	$ 34,734	$ 35,302	$ 33,969	$ 33,888	$ 33,277	$ 33,205	$ 32,265	$ 32,091
Commodity		$ 142,028	$ 142,028	$ 147,868	$ 151,805	$ 159,444	$ 165,012	$ 170,774	$ 176,738	$ 182,911	$ 189,300	$ 195,912
		$ 173,374	$ 176,361	$ 182,595	$ 186,539	$ 194,746	$ 198,980	$ 204,663	$ 210,015	$ 216,116	$ 221,565	$ 228,003
Delivery Bill Impact			9 53%	1 15%	0 02%	1 63%	-3 78%	-0 24%	-1 80%	-0 22%	-2 83%	-0 54%
Total Bill Impact			1 72%	3 53%	2 16%	4 40%	2 17%	2 86%	2 62%	2 91%	2 52%	2 91%
Annual Delivery Bill Change			$ 35,853 00	$ 4,725 37	$ 89 26	$ 6,810 11	$ (15,998 20)	$ (962 86)	$ (7,339 34)	$ (860 53)	$ (11,284 78)	$ (2,089 09)
Annual Commodity Bill Change			$ -	$ 70,074 57	$ 47,248 53	$ 91,670 45	$ 66,810 24	$ 69,148 60	$ 71,568 80	$ 74,073 71	$ 76,666 28	$ 79,349 60
Annual Total Bill Changes			$ 35,853 00	$ 74,799 95	$ 47,337 79	$ 98,480 56	$ 50,812 03	$ 68,185 74	$ 64,229 46	$ 73,213 18	$ 65,381 50	$ 77,260 51

MFC

Uncollectible	0 290%
WC	0 363%
Credit and Collection	0 00006
Electric Supply Procu	0 0001

REDACTED DOCUMENT
REPOWERING OPTION 2
BILL IMPACTS

SC1

600 kWh		without RSS	with RSS									
		2018	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Customer Charge		$17.00	$17.00	$17.00	$17.00	$17.00	$17.00	$17.00	$17.00	$17.00	$17.00	$17.00
T&D Energy Charge	kWh x	$0.04758	$0.04758	$0.04758	$0.04758	$0.04758	$0.04758	$0.04758	$0.04758	$0.04758	$0.04758	$0.04758
Deferral Recovery	kWh x	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
RSS	kWh x	$0.00000	$0.00133	$0.00137	$0.00140	$0.00144	$0.00147	$0.00151	$0.00155	$0.00066	$0.00000	$0.00000
Legacy Transition Charge	kWh x	$0.00151	$0.00151	$0.00163	$0.00161	$0.00184	$0.00125	$0.00119	$0.00092	$0.00103	$0.00017	$0.00008
Electricity Supply Rate Mechanism	kWh x	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
Commodity Energy Charge	kWh x	$0.07266	$0.07266	$0.07552	$0.07677	$0.08051	$0.08333	$0.08624	$0.08926	$0.09239	$0.09562	$0.09897
Transmission Revenue Adjustment Charge	kWh x	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
Systems Benefits Charge	kWh x	$0.00551	$0.00551	$0.00551	$0.00551	$0.00551	$0.00551	$0.00551	$0.00551	$0.00551	$0.00551	$0.00551
Incremental State Assessment Surcharge	kWh x	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
Merchant Function Charge	kWh x	$0.00269	$0.00269	$0.00277	$0.00281	$0.00291	$0.00298	$0.00306	$0.00314	$0.00323	$0.00331	$0.00341
NYPA Hydro Benefit Reconcilation Charge	kWh x	($0.00220)	($0.00220)	($0.00227)	($0.00229)	($0.00235)	($0.00239)	($0.00244)	($0.00248)	($0.00253)	($0.00258)	($0.00263)
Gross Receipts Tax												
Commodity	Bill /	0.9900	0.9900	0 9900	0.9900	0.9900	0.9900	0.9900	0.9900	0.9900	0.9900	0.9900
Delivery	Bill /	0.9700	0.9700	0 9700	0.9700	0.9700	0.9700	0.9700	0.9700	0.9700	0.9700	0.9700
Delivery		$49 94	$50.76	$50.82	$50.81	$50.94	$50.57	$50.53	$50.35	$49.85	$48.87	$48.78
Commodity		$45.67	$45.67	$47.45	$48.23	$50.55	$52.31	$54.12	$56.00	$57.95	$59.96	$62.04
		$95.61	$96.43	$98 27	$99.04	$101.49	$102.88	$104.65	$106.35	$107.79	$108.83	$110.83
Delivery Bill Impact			1.65%	0.11%	0.00%	0 24%	-0.73%	-0.07%	-0.35%	-1.00%	-1.95%	-0.19%
Total Bill Impact			0.86%	1.90%	0.79%	2.47%	1.36%	1.73%	1.62%	1.35%	0.97%	1.83%
Annual Delivery Bill Change			$ 9.89	$ 0.66	$ (0.03)	$ 1.49	$ (4.45)	$ (0.45)	$ (2.15)	$ (6.06)	$ (11.67)	$ (1.10)
Annual Commodity Bill Change			$ -	$ 21 33	$ 9.37	$ 27.89	$ 21.05	$ 21.78	$ 22.55	$ 23.34	$ 24.15	$ 25.00
Annual Total Bill Changes			$ 9.89	$ 21 99	$ 9.34	$ 29.38	$ 16.60	$ 21.34	$ 20.40	$ 17.28	$ 12.49	$ 23.90

MFC	
Uncollectible	2.340%
WC	0.363%
Credit and Collections	0.00063
Electric Supply Procurement	0.0001

REDACTED DOCUMENT

REPOWERING OPTION 2
BILL IMPACTS

SC2ND

1500 kWh		without RSS	with RSS									
		2018	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Customer Charge		$21.02	$21.02	$21.02	$21.02	$21.02	$21.02	$21.02	$21.02	$21.02	$21.02	$21.02
T&D Energy Charge	kWh x	$0.05696	$0.05696	$0.05696	$0.05696	$0.05696	$0.05696	$0.05696	$0.05696	$0.05696	$0.05696	$0.05696
Deferral Recovery	kWh x	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
RSS	kWh x	$0.00000	$0.00143	$0.00146	$0.00150	$0.00154	$0.00158	$0.00162	$0.00166	$0.00071	$0.00000	$0.00000
Legacy Transition Charge	kWh x	$0.00151	$0.00151	$0.00163	$0.00161	$0.00184	$0.00125	$0.00119	$0.00092	$0.00103	$0.00017	$0.00008
Electricity Supply Rate Mechanism	kWh x	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
Commodity Energy Charge	kWh x	$0.07702	$0.07702	$0.08000	$0.08105	$0.08496	$0.08793	$0.09101	$0.09419	$0.09749	$0.10090	$0.10443
Transmission Revenue Adjustment Charge	kWh x	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
Systems Benefits Charge	kWh x	$0.00551	$0.00551	$0.00551	$0.00551	$0.00551	$0.00551	$0.00551	$0.00551	$0.00551	$0.00551	$0.00551
Incremental State Assessment Surcharge	kWh x	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
Merchant Function Charge	kWh x	$0.00281	$0.00281	$0.00289	$0.00292	$0.00303	$0.00311	$0.00319	$0.00328	$0.00337	$0.00346	$0.00355
Gross Receipts Tax												
Commodity	Bill /	0.9900	0.9900	0.9900	0.9900	0.9900	0.9900	0.9900	0 9900	0.9900	0.9900	0.9900
Delivery	Bill /	0.9900	0.9900	0.9900	0.9900	0.9900	0.9900	0.9900	0 9900	0.9900	0.9900	0.9900
Delivery		$ 118.17	$ 120.34	$ 120.57	$ 120.60	$ 121.00	$ 120 16	$ 120.14	$ 119.78	$ 118.52	$ 116.15	$ 116.00
Commodity		$ 120.95	$ 120.95	$ 125.60	$ 127.23	$ 133.31	$ 137 94	$ 142.73	$ 147.68	$ 152.81	$ 158.12	$ 163.62
		$ 239.12	$ 241.29	$ 246.18	$ 247.83	$ 254.31	$ 258 10	$ 262.87	$ 267.46	$ 271.34	$ 274.27	$ 279.62
Delivery Bill Impact			1.83%	0.20%	0.02%	0.33%	-0.69%	-0.01%	-0.30%	-1.05%	-2.00%	-0.12%
Total Bill Impact			0 91%	2.03%	0.67%	2.61%	1.49%	1.85%	1.75%	1.45%	1.08%	1.95%
Annual Delivery Bill Change			$ 26.00	$ 2.84	$ 0.34	$ 4.76	$ (10.04)	$ (0.22)	$ (4.34)	$ (15.11)	$ (28.52)	$ (1.74)
Annual Commodity Bill Change			$ -	$ 55.80	$ 19.55	$ 72 93	$ 55.53	$ 57.47	$ 59.48	$ 61.56	$ 63.72	$ 65 95
Annual Total Bill Changes			$ 26.00	$ 58.64	$ 19.89	$ 77.69	$ 45.48	$ 57.25	$ 55.14	$ 46.46	$ 35.20	$ 64 21

MFC	
Uncollectible	2.340%
WC	0.363%
Credit and Collections	0.0006
Electric Supply Procurement	0.0001

SC2D

		without RSS	with RSS									
7,200 kWh												
25 kW		2018	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Customer Charge		$52 52	$52 52	$52 52	$52 52	$52 52	$52 52	$52 52	$52 52	$52 52	$52 52	$52 52
T&D Demand Charge	kW x	$10 27	$10 27	$10 27	$10 27	$10 27	$10 27	$10 27	$10 27	$10 27	$10 27	$10 27
Deferral Recovery	kW x	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00
RSS	kW x	$0 00	$0 34	$0 34	$0 35	$0 36	$0 37	$0 38	$0 39	$0 17	$0 00	$0 00
Legacy Transition Charge	kWh x	$0 00151	$0 00151	$0 00163	$0 00161	$0 00184	$0 00125	$0 00119	$0 00092	$0 00103	$0 00017	$0 00008
Commodity Energy Charge	kWh x	$0 07091	$0 07091	$0 07374	$0 07498	$0 07867	$0 08142	$0 08427	$0 08722	$0 09027	$0 09343	$0 09670
Transmission Revenue Adjustment Charge	kWh x	$0 00000	$0 00000	$0 00000	$0 00000	$0 00000	$0 00000	$0 00000	$0 00000	$0 00000	$0 00000	$0 00000
Systems Benefits Charge	kWh x	$0 00551	$0 00551	$0 00551	$0 00551	$0 00551	$0 00551	$0 00551	$0 00551	$0 00551	$0 00551	$0 00551
Incremental State Assessment Surcharge	kW x	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00
Merchant Function Charge	kWh x	$0 00062	$0 00062	$0 00064	$0 00065	$0 00067	$0 00069	$0 00071	$0 00073	$0 00075	$0 00077	$0 00079
Gross Receipts Tax												
Commodity	Bill /	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900
Delivery	Bill /	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900
Delivery		$ 363 44	$ 371 91	$ 373 01	$ 373 10	$ 374 95	$ 370 88	$ 370 74	$ 368 95	$ 364 18	$ 353 73	$ 353 03
Commodity		$ 520 27	$ 520 27	$ 540 98	$ 550 05	$ 577 03	$ 597 18	$ 618 04	$ 639 63	$ 661 98	$ 685 11	$ 709 05
		$ 883 72	$ 892 18	$ 913 99	$ 923 14	$ 951 98	$ 968 06	$ 988 78	$ 1,008 58	$ 1,026 16	$ 1,038 84	$ 1,062 08
Delivery Bill Impact			2 33%	0 30%	0 02%	0 50%	-1 09%	-0 04%	-0 48%	-1 29%	-2 87%	-0 20%
Total Bill Impact			0 96%	2 44%	1 00%	3 12%	1 69%	2 14%	2 00%	1 74%	1 24%	2 24%
Annual Delivery Bill Change			$ 101 60	$ 13 21	$ 1 04	$ 22 25	$ (48 83)	$ (1 67)	$ (21 51)	$ (57 19)	$ (125 46)	$ (8 36)
Annual Commodity Bill Change			$ -	$ 248 41	$ 108 86	$ 323 74	$ 241 86	$ 250 33	$ 259 09	$ 268 16	$ 277 54	$ 287 26
Annual Total Bill Changes			$ 101 60	$ 261 62	$ 109 90	$ 345 99	$ 193 04	$ 248 66	$ 237 58	$ 210 97	$ 152 09	$ 278 90

MFC	
Uncollectible	0 290%
WC	0 363%
Credit and Collections	0 00006
Electric Supply Procurement	0 0001

REDACTED DOCUMENT
REPOWERING OPTION 2
BILL IMPACTS

SC3 Primary

		without RSS	with RSS									
216,000 kWh												
500 kW		2018	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Customer Charge		$436 70	$436 70	$436 70	$436 70	$436 70	$436 70	$436 70	$436 70	$436 70	$436 70	$436 70
T&D Demand Charge	kW x	$8 15	$8 15	$8 15	$8 15	$8 15	$8 15	$8 15	$8 15	$8 15	$8 15	$8 15
Deferral Recovery	kW x	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00
RSS	kW x	$0 00	$0 40	$0 41	$0 42	$0 43	$0 44	$0 45	$0 46	$0 20	$0 00	$0 00
Legacy Transition Charge	kWh x	$0 00151	$0 00151	$0 00163	$0 00161	$0 00184	$0 00125	$0 00119	$0 00092	$0 00103	$0 00017	$0 00008
Commodity Energy Charge	kWh x	$0 06452	$0 06452	$0 06715	$0 06934	$0 07281	$0 07536	$0 07800	$0 08073	$0 08355	$0 08648	$0 08950
Transmission Revenue Adjustment Charge	kWh x	$0 00000	$0 00000	$0 00000	$0 00000	$0 00000	$0 00000	$0 00000	$0 00000	$0 00000	$0 00000	$0 00000
Systems Benefits Charge	kWh x	$0 00551	$0 00551	$0 00551	$0 00551	$0 00551	$0 00551	$0 00551	$0 00551	$0 00551	$0 00551	$0 00551
Incremental State Assessment Surcharge	kW x	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00
Merchant Function Charge	kWh x	$0 00058	$0 00058	$0 00060	$0 00061	$0 00064	$0 00065	$0 00067	$0 00069	$0 00071	$0 00072	$0 00074
Gross Receipts Tax												
Commodity	Bill /	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900
Delivery	Bill /	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900
Delivery		$ 6,088 70	$ 6,288 58	$ 6,320 25	$ 6,321 47	$ 6,375 67	$ 6,252 14	$ 6,246 47	$ 6,191 18	$ 6,084 16	$ 5,797 33	$ 5,776 43
Commodity		$ 14,203 71	$ 14,203 71	$ 14,780 98	$ 15,263 04	$ 16,024 66	$ 16,584 30	$ 17,163 53	$ 17,763 03	$ 18,383 52	$ 19,025 72	$ 19,690 40
		$ 20,292 41	$ 20,492 29	$ 21,101 24	$ 21,584 51	$ 22,400 33	$ 22,836 44	$ 23,410 01	$ 23,954 21	$ 24,467 68	$ 24,823 05	$ 25,466 83
Delivery Bill Impact			3 28%	0 50%	0 02%	0 86%	-1 94%	-0 09%	-0 89%	-1 73%	-4 71%	-0 36%
Total Bill Impact			0 99%	2 97%	2 29%	3 78%	1 95%	2 51%	2 32%	2 14%	1 45%	2 59%
Annual Delivery Bill Change			$ 2,398 57	$ 380 08	$ 14 58	$ 650 38	$ (1,482 30)	$ (68 01)	$ (663 58)	$ (1,284 15)	$ (3,442 02)	$ (250 74)
Annual Commodity Bill Change			$ -	$ 6,927 27	$ 5,784 71	$ 9,139 44	$ 6,715 70	$ 6,950 75	$ 7,194 02	$ 7,445 81	$ 7,706 42	$ 7,976 14
Annual Total Bill Changes			$ 2,398 57	$ 7,307 35	$ 5,799 29	$ 9,789 82	$ 5,233 40	$ 6,882 73	$ 6,530 44	$ 6,161 67	$ 4,264 39	$ 7,725 40

MFC	
Uncollectible	0 290%
WC	0 363%
Credit and Collections	0 00006
Electric Supply Procurer	0 0001

REDACTED DOCUMENT
REPOWERING OPTION 2
BILL IMPACTS

SC3A Transmission		without RSS	with RSS									
2,304,000 kWh		2018	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
4,000 kW												
Customer Charge		$3,500 00	$3,500 00	$3,500 00	$3,500 00	$3,500 00	$3,500 00	$3,500 00	$3,500 00	$3,500 00	$3,500 00	$3,500 00
T&D Demand Charge	kW x	$2 84	$2 84	$2 84	$2 84	$2 84	$2 84	$2 84	$2 84	$2 84	$2 84	$2 84
Deferral Recovery	kW x	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00
RSS	kW x	$0 00	$0 34	$0 35	$0 36	$0 37	$0 37	$0 38	$0 39	$0 17	$0 00	$0 00
Legacy Transition Charge	kWh x	$0 00151	$0 00151	$0 00163	$0 00161	$0 00184	$0 00125	$0 00119	$0 00092	$0 00103	$0 00017	$0 00008
Commodity Energy Charge	kWh x	$0 06047	$0 06047	$0 06297	$0 06465	$0 06791	$0 07028	$0 07274	$0 07529	$0 07793	$0 08065	$0 08348
Transmission Revenue Adjustment Charge	kWh x	$0 00000	$0 00000	$0 00000	$0 00000	$0 00000	$0 00000	$0 00000	$0 00000	$0 00000	$0 00000	$0 00000
Systems Benefits Charge	kWh x	$0 00551	$0 00551	$0 00551	$0 00551	$0 00551	$0 00551	$0 00551	$0 00551	$0 00551	$0 00551	$0 00551
Incremental State Assessment Surcharge	kW x	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00
Merchant Function Charge	kWh x	$0 00055	$0 00055	$0 00057	$0 00058	$0 00060	$0 00062	$0 00064	$0 00065	$0 00067	$0 00069	$0 00071
Gross Receipts Tax												
Commodity	Bill /	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900
Delivery	Bill /	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900
Delivery		$ 31,345	$ 32,716	$ 33,035	$ 33,028	$ 33,587	$ 32,249	$ 32,167	$ 31,556	$ 30,920	$ 28,237	$ 28,014
Commodity		$ 142,028	$ 142,028	$ 147,868	$ 151,805	$ 159,444	$ 165,012	$ 170,774	$ 176,738	$ 182,911	$ 189,300	$ 195,912
		$ 173,374	$ 174,744	$ 180,903	$ 184,834	$ 193,031	$ 197,260	$ 202,941	$ 208,294	$ 213,831	$ 217,537	$ 223,927
Delivery Bill Impact			4 37%	0 97%	-0 02%	1 69%	-3 98%	-0 25%	-1 90%	-2 01%	-8 68%	-0 79%
Total Bill Impact			0 79%	3 52%	2 17%	4 43%	2 19%	2 88%	2 64%	2 66%	1 73%	2 94%
Annual Delivery Bill Change			$ 16,450 57	$ 3,825 88	$ (78 53)	$ 6,697 49	$ (16,057 09)	$ (977 53)	$ (7,336 53)	$ (7,628 75)	$ (32,190 88)	$ (2,674 55)
Annual Commodity Bill Change			$ -	$ 70,074 57	$ 47,248 53	$ 91,670 45	$ 66,810 24	$ 69,148 60	$ 71,568 80	$ 74,073 71	$ 76,666 28	$ 79,349 60
Annual Total Bill Changes			$ 16,450 57	$ 73,900 45	$ 47,170 01	$ 98,367 94	$ 50,753 14	$ 68,171 06	$ 64,232 27	$ 66,444 95	$ 44,475 41	$ 76,675 05

MFC	
Uncollectible	0 290%
WC	0 363%
Credit and Collectior	0 00006
Electric Supply Procı	0 0001

TRANSMISSION UPGRADES
BILL IMPACTS

SC1

600 kWh		without RSS	with RSS									
		2018	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Customer Charge		$17.00	$17.00	$17.00	$17.00	$17.00	$17.00	$17.00	$17.00	$17.00	$17.00	$17.00
T&D Energy Charge	kWh x	$0.04758	$0.04758	$0.04758	$0.04758	$0.04758	$0.04758	$0.04758	$0.04758	$0.04758	$0.04758	$0.04758
Deferral Recovery	kWh x	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
RSS	kWh x	$0.00000	$0.00040	$0.00040	$0.00040	$0.00039	$0.00039	$0.00039	$0.00038	$0.00038	$0.00038	$0.00038
Legacy Transition Charge	kWh x	$0.00151	$0.00151	$0.00163	$0.00161	$0.00184	$0.00125	$0.00119	$0.00092	$0.00103	$0.00017	$0.00008
Electricity Supply Rate Mechanism	kWh x	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
Commodity Energy Charge	kWh x	$0.07266	$0.07266	$0.07552	$0.07677	$0.08051	$0.08333	$0.08624	$0.08926	$0.09239	$0.09562	$0.09897
Transmission Revenue Adjustment Charge	kWh x	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
Systems Benefits Charge	kWh x	$0.00551	$0.00551	$0.00551	$0.00551	$0.00551	$0.00551	$0.00551	$0.00551	$0.00551	$0.00551	$0.00551
Incremental State Assessment Surcharge	kWh x	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
Merchant Function Charge	kWh x	$0.00269	$0.00269	$0.00277	$0.00281	$0.00291	$0.00298	$0.00306	$0.00314	$0.00323	$0.00331	$0.00341
NYPA Hydro Benefit Reconcilation Charge	kWh x	($0.00220)	($0.00220)	($0.00227)	($0.00229)	($0.00235)	($0.00239)	($0.00244)	($0.00248)	($0.00253)	($0.00258)	($0.00263)
Gross Receipts Tax												
Commodity	Bill /	0.9900	0.9900	0.9900	0.9900	0.9900	0.9900	0.9900	0 9900	0.9900	0.9900	0.9900
Delivery	Bill /	0.9700	0.9700	0.9700	0.9700	0.9700	0.9700	0.9700	0 9700	0.9700	0.9700	0.9700
Delivery		$49.94	$50.19	$50.22	$50 19	$50.29	$49.90	$49.84	$49.63	$49.67	$49.11	$49.02
Commodity		$45.67	$45.67	$47.45	$48 23	$50.55	$52.31	$54.12	$56.00	$57.95	$59.96	$62.04
		$95.61	$95.86	$97.67	$98.42	$100.85	$102.21	$103.96	$105.64	$107.62	$109.07	$111.06
Delivery Bill Impact			0.50%	0.06%	-0.05%	0.20%	-0.78%	-0.12%	-0.41%	0.08%	-1 14%	-0.19%
Total Bill Impact			0.26%	1.89%	0.77%	2.46%	1.35%	1.72%	1.61%	1.88%	1.34%	1.82%
Annual Delivery Bill Change			$ 2.98	$ 0.39	$ (0.30)	$ 1.21	$ (4.73)	$ (0.74)	$ (2.45)	$ 0.49	$ (6.79)	$ (1 12)
Annual Commodity Bill Change			$ -	$ 21.33	$ 9 37	$ 27.89	$ 21.05	$ 21.78	$ 22.55	$ 23.34	$ 24.15	$ 25.00
Annual Total Bill Changes			$ 2.98	$ 21.72	$ 9.07	$ 29.10	$ 16.31	$ 21.04	$ 20.10	$ 23.83	$ 17.37	$ 23.88

MFC	
Uncollectible	2.340%
WC	0.363%
Credit and Collections	0.00063
Electric Supply Procurement	0.0001

REDACTED DOCUMENT

TRANSMISSION UPGRADES
BILL IMPACTS

SC2ND

1500 kWh		without RSS	with RSS									
		2018	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Customer Charge		$21.02	$21.02	$21.02	$21.02	$21.02	$21.02	$21.02	$21.02	$21.02	$21.02	$21.02
T&D Energy Charge	kWh x	$0.05696	$0.05696	$0.05696	$0.05696	$0.05696	$0.05696	$0.05696	$0.05696	$0.05696	$0.05696	$0.05696
Deferral Recovery	kWh x	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
RSS	kWh x	$0.00000	$0.00043	$0.00043	$0.00042	$0.00042	$0.00042	$0.00041	$0.00041	$0.00041	$0.00041	$0.00040
Legacy Transition Charge	kWh x	$0.00151	$0.00151	$0.00163	$0.00161	$0.00184	$0.00125	$0.00119	$0.00092	$0.00103	$0.00017	$0.00008
Electricity Supply Rate Mechanism	kWh x	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
Commodity Energy Charge	kWh x	$0.07702	$0.07702	$0.08000	$0.08105	$0.08496	$0.08793	$0.09101	$0.09419	$0.09749	$0.10090	$0.10443
Transmission Revenue Adjustment Charge	kWh x	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
Systems Benefits Charge	kWh x	$0.00551	$0.00551	$0.00551	$0.00551	$0.00551	$0.00551	$0.00551	$0.00551	$0.00551	$0.00551	$0.00551
Incremental State Assessment Surcharge	kWh x	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
Merchant Function Charge	kWh x	$0.00281	$0.00281	$0.00289	$0.00292	$0.00303	$0.00311	$0.00319	$0.00328	$0.00337	$0.00346	$0.00355
Gross Receipts Tax												
Commodity	Bill /	0.9900	0.9900	0.9900	0.9900	0.9900	0.9900	0.9900	0 9900	0.9900	0.9900	0.9900
Delivery	Bill /	0.9900	0.9900	0.9900	0.9900	0.9900	0.9900	0.9900	0 9900	0.9900	0.9900	0.9900
Delivery		$ 118.17	$ 118.82	$ 119.00	$ 118.97	$ 119.31	$ 118.41	$ 118.32	$ 117.90	$ 118.07	$ 116.76	$ 116.61
Commodity		$ 120.95	$ 120.95	$ 125.60	$ 127.23	$ 133.31	$ 137.94	$ 142.73	$ 147.68	$ 152.81	$ 158.12	$ 163.62
		$ 239.12	$ 239.77	$ 244.61	$ 246.20	$ 252.62	$ 256.34	$ 261.05	$ 265.58	$ 270.88	$ 274.88	$ 280.23
Delivery Bill Impact			0.55%	0 15%	-0.03%	0.28%	-0.75%	-0.07%	-0.36%	0.15%	-1.11%	-0.13%
Total Bill Impact			0.27%	2.01%	0.65%	2.60%	1.48%	1.84%	1.73%	2.00%	1.48%	1.94%
Annual Delivery Bill Change			$ 7.82	$ 2.18	$ (0.38)	$ 4.02	$ (10.80)	$ (0.99)	$ (5.13)	$ 2.10	$ (15.71)	$ (1.79)
Annual Commodity Bill Change			$ -	$ 55.80	$ 19.55	$ 72.93	$ 55.53	$ 57.47	$ 59.48	$ 61.56	$ 63.72	$ 65.95
Annual Total Bill Changes			$ 7.82	$ 57.97	$ 19.17	$ 76.95	$ 44.73	$ 56.48	$ 54.35	$ 63.66	$ 48.01	$ 64.15

MFC	
Uncollectible	2.340%
WC	0.363%
Credit and Collections	0.0006
Electric Supply Procurement	0.0001

SC2D

		without RSS	with RSS									
7,200 kWh 25 kW		2018	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Customer Charge		$52 52	$52 52	$52 52	$52 52	$52 52	$52 52	$52 52	$52 52	$52 52	$52 52	$52 52
T&D Demand Charge	kW x	$10 27	$10 27	$10 27	$10 27	$10 27	$10 27	$10 27	$10 27	$10 27	$10 27	$10 27
Deferral Recovery	kW x	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00
RSS	kW x	$0 00	$0 10	$0 10	$0 10	$0 10	$0 10	$0 10	$0 10	$0 10	$0 10	$0 09
Legacy Transition Charge	kWh x	$0 00151	$0 00151	$0 00163	$0 00161	$0 00184	$0 00125	$0 00119	$0 00092	$0 00103	$0 00017	$0 00008
Commodity Energy Charge	kWh x	$0 07091	$0 07091	$0 07374	$0 07498	$0 07867	$0 08142	$0 08427	$0 08722	$0 09027	$0 09343	$0 09670
Transmission Revenue Adjustment Charge	kWh x	$0 00000	$0 00000	$0 00000	$0 00000	$0 00000	$0 00000	$0 00000	$0 00000	$0 00000	$0 00000	$0 00000
Systems Benefits Charge	kWh x	$0 00551	$0 00551	$0 00551	$0 00551	$0 00551	$0 00551	$0 00551	$0 00551	$0 00551	$0 00551	$0 00551
Incremental State Assessment Surcharge	kW x	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00
Merchant Function Charge	kWh x	$0 00062	$0 00062	$0 00064	$0 00065	$0 00067	$0 00069	$0 00071	$0 00073	$0 00075	$0 00077	$0 00079
Gross Receipts Tax												
Commodity	Bill /	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900
Delivery	Bill /	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900
Delivery		$ 363 44	$ 365 99	$ 366 86	$ 366 72	$ 368 33	$ 364 01	$ 363 62	$ 361 57	$ 362 42	$ 356 14	$ 355 42
Commodity		$ 520 27	$ 520 27	$ 540 98	$ 550 05	$ 577 03	$ 597 18	$ 618 04	$ 639 63	$ 661 98	$ 685 11	$ 709 05
		$ 883 72	$ 886 27	$ 907 84	$ 916 76	$ 945 35	$ 961 19	$ 981 66	$ 1,001 21	$ 1,024 39	$ 1,041 24	$ 1,064 47
Delivery Bill Impact			0 70%	0 24%	-0 04%	0 44%	-1 17%	-0 11%	-0 56%	0 23%	-1 73%	-0 20%
Total Bill Impact			0 29%	2 43%	0 98%	3 12%	1 68%	2 13%	1 99%	2 32%	1 64%	2 23%
Annual Delivery Bill Change			$ 30 63	$ 10 44	$ (1 79)	$ 19 36	$ (51 78)	$ (4 69)	$ (24 59)	$ 10 11	$ (75 34)	$ (8 56)
Annual Commodity Bill Change			$ -	$ 248 41	$ 108 86	$ 323 74	$ 241 86	$ 250 33	$ 259 09	$ 268 16	$ 277 54	$ 287 26
Annual Total Bill Changes			$ 30 63	$ 258 86	$ 107 08	$ 343 10	$ 190 08	$ 245 64	$ 234 50	$ 278 26	$ 202 20	$ 278 70

MFC	
Uncollectible	0 290%
WC	0 363%
Credit and Collections	0 00006
Electric Supply Procurement	0 0001

REDACTED DOCUMENT
TRANSMISSION UPGRADES
BILL IMPACTS

SC3 Primary

		without RSS	with RSS									
216,000 kWh												
500 kW		2018	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Customer Charge		$436 70	$436 70	$436 70	$436 70	$436 70	$436 70	$436 70	$436 70	$436 70	$436 70	$436 70
T&D Demand Charge	kW x	$8 15	$8 15	$8 15	$8 15	$8 15	$8 15	$8 15	$8 15	$8 15	$8 15	$8 15
Deferral Recovery	kW x	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00
RSS	kW x	$0 00	$0 12	$0 12	$0 12	$0 12	$0 12	$0 11	$0 11	$0 11	$0 11	$0 11
Legacy Transition Charge	kWh x	$0 00151	$0 00151	$0 00163	$0 00161	$0 00184	$0 00125	$0 00119	$0 00092	$0 00103	$0 00017	$0 00008
Commodity Energy Charge	kWh x	$0 06452	$0 06452	$0 06715	$0 06934	$0 07281	$0 07536	$0 07800	$0 08073	$0 08355	$0 08648	$0 08950
Transmission Revenue Adjustment Charge	kWh x	$0 00000	$0 00000	$0 00000	$0 00000	$0 00000	$0 00000	$0 00000	$0 00000	$0 00000	$0 00000	$0 00000
Systems Benefits Charge	kWh x	$0 00551	$0 00551	$0 00551	$0 00551	$0 00551	$0 00551	$0 00551	$0 00551	$0 00551	$0 00551	$0 00551
Incremental State Assessment Surcharge	kW x	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00
Merchant Function Charge	kWh x	$0 00058	$0 00058	$0 00060	$0 00061	$0 00064	$0 00065	$0 00067	$0 00069	$0 00071	$0 00072	$0 00074
Gross Receipts Tax												
Commodity	Bill /	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900
Delivery	Bill /	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900
Delivery		$ 6,088 70	$ 6,148 96	$ 6,175 19	$ 6,170 84	$ 6,219 35	$ 6,090 01	$ 6,078 40	$ 6,017 03	$ 6,042 41	$ 5,854 16	$ 5,832 87
Commodity		$ 14,203 71	$ 14,203 71	$ 14,780 98	$ 15,263 04	$ 16,024 66	$ 16,584 30	$ 17,163 53	$ 17,763 03	$ 18,383 52	$ 19,025 72	$ 19,690 40
		$ 20,292 41	$ 20,352 67	$ 20,956 17	$ 21,433 88	$ 22,244 01	$ 22,674 31	$ 23,241 93	$ 23,780 06	$ 24,425 93	$ 24,879 88	$ 25,523 26
Delivery Bill Impact			0 99%	0 43%	-0 07%	0 79%	-2 08%	-0 19%	-1 01%	0 42%	-3 12%	-0 36%
Total Bill Impact			0 30%	2 97%	2 28%	3 78%	1 93%	2 50%	2 32%	2 72%	1 86%	2 59%
Annual Delivery Bill Change			$ 723 12	$ 314 74	$ (52 20)	$ 582 13	$ (1,552 05)	$ (139 31)	$ (736 46)	$ 304 52	$ (2,258 93)	$ (255 55)
Annual Commodity Bill Change			$ -	$ 6,927 27	$ 5,784 71	$ 9,139 44	$ 6,715 70	$ 6,950 75	$ 7,194 02	$ 7,445 81	$ 7,706 42	$ 7,976 14
Annual Total Bill Changes			$ 723 12	$ 7,242 01	$ 5,732 51	$ 9,721 57	$ 5,163 65	$ 6,811 44	$ 6,457 56	$ 7,750 33	$ 5,447 49	$ 7,720 59

MFC

Uncollectible	0 290%
WC	0 363%
Credit and Collections	0 00006
Electric Supply Procurement	0 0001

REDACTED DOCUMENT
TRANSMISSION UPGRADES
BILL IMPACTS

SC3A Transmission		without RSS	with RSS									
2,304,000 kWh		2018	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
4,000 kW												
Customer Charge		$3,500 00	$3,500 00	$3,500 00	$3,500 00	$3,500 00	$3,500 00	$3,500 00	$3,500 00	$3,500 00	$3,500 00	$3,500 00
T&D Demand Charge	kW x	$2 84	$2 84	$2 84	$2 84	$2 84	$2 84	$2 84	$2 84	$2 84	$2 84	$2 84
Deferral Recovery	kW x	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00
RSS	kW x	$0 00	$0 10	$0 10	$0 10	$0 10	$0 10	$0 10	$0 10	$0 10	$0 10	$0 10
Legacy Transition Charge	kWh x	$0 00151	$0 00151	$0 00163	$0 00161	$0 00184	$0 00125	$0 00119	$0 00092	$0 00103	$0 00017	$0 00008
Commodity Energy Charge	kWh x	$0 06047	$0 06047	$0 06297	$0 06465	$0 06791	$0 07028	$0 07274	$0 07529	$0 07793	$0 08065	$0 08348
Transmission Revenue Adjustment Charge	kWh x	$0 00000	$0 00000	$0 00000	$0 00000	$0 00000	$0 00000	$0 00000	$0 00000	$0 00000	$0 00000	$0 00000
Systems Benefits Charge	kWh x	$0 00551	$0 00551	$0 00551	$0 00551	$0 00551	$0 00551	$0 00551	$0 00551	$0 00551	$0 00551	$0 00551
Incremental State Assessment Surcharge	kW x	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00
Merchant Function Charge	kWh x	$0 00055	$0 00055	$0 00057	$0 00058	$0 00060	$0 00062	$0 00064	$0 00065	$0 00067	$0 00069	$0 00071
Gross Receipts Tax												
Commodity	Bill /	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900
Delivery	Bill /	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900
Delivery		$ 31,345	$ 31,759	$ 32,040	$ 31,995	$ 32,514	$ 31,137	$ 31,014	$ 30,361	$ 30,634	$ 28,627	$ 28,402
Commodity		$ 142,028	$ 142,028	$ 147,868	$ 151,805	$ 159,444	$ 165,012	$ 170,774	$ 176,738	$ 182,911	$ 189,300	$ 195,912
		$ 173,374	$ 173,787	$ 179,908	$ 183,801	$ 191,959	$ 196,148	$ 201,789	$ 207,100	$ 213,545	$ 217,927	$ 224,314
Delivery Bill Impact			1 32%	0 89%	-0 14%	1 62%	-4 24%	-0 39%	-2 11%	0 90%	-6 55%	-0 79%
Total Bill Impact			0 24%	3 52%	2 16%	4 44%	2 18%	2 88%	2 63%	3 11%	2 05%	2 93%
Annual Delivery Bill Change			$ 4,959 53	$ 3,377 71	$ (536 52)	$ 6,229 42	$ (16,535 49)	$ (1,466 52)	$ (7,836 36)	$ 3,267 11	$ (24,076 65)	$ (2,707 52)
Annual Commodity Bill Change			$ -	$ 70,074 57	$ 47,248 53	$ 91,670 45	$ 66,810 24	$ 69,148 60	$ 71,568 80	$ 74,073 71	$ 76,666 28	$ 79,349 60
Annual Total Bill Changes			$ 4,959 53	$ 73,452 28	$ 46,712 01	$ 97,899 87	$ 50,274 75	$ 67,682 08	$ 63,732 43	$ 77,340 81	$ 52,589 64	$ 76,642 08

MFC	
Uncollectible	0 290%
WC	0 363%
Credit and Collections	0 00006
Electric Supply Procurement	0 0001

Exhibit 5

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID
ALLOCATION OF ESTIMATED RELIABILITY SUPPORT SERVICES COSTS
ANNUAL NET COSTS - REPOWERING OPTION 1

Design Service Class	12-months ended 3-31-2016 kW Billed (A)	12-months ended 3-31-2016 kWh Sales (B)	Transmission Plant Allocator (C)	Allocation of Estimated RSS Costs (D)	2018 Surcharge Rate (E)	2019	2020	2021	2022	2023	2024	2025	2026	2027
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]														
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]														
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]				[redacted]										
[redacted]														
[redacted]	[redacted]	[redacted]		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]			[redacted]	[redacted]		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

A Joint Proposal, Appendix 2, Schedule 6, Column A less EZR and Excelsior
B Joint Proposal, Appendix 2, Schedule 6, Column A less EZR and Excelsior
C Exhibt ____ (E-RDP-3), Schedule 3, Page 1 of 8, Line 17
D RSS costs allocated by Column C
E Column (D) / Column (A) or Column (B)

REDACTED DOCUMENT

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID
ALLOCATION OF ESTIMATED RELIABILITY SUPPORT SERVICES COSTS
ANNUAL NET COSTS - REPOWERING OPTION 2

Design Service Class	12-months ended 3-31-2016 kW Billed (A)	12-months ended 3-31-2016 kWh Sales (B)	Transmission Plant Allocator (C)	Allocation of Estimated RSS Costs (D)	2018 Surcharge Rate (E)	2019	2020	2021	2022	2023	2024	2025
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]												
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]												
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]				[redacted]								
[redacted]												
[redacted]	[redacted]	[redacted]		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]			[redacted]	[redacted]		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

A Joint Proposal, Appendix 2, Schedule 6, Column A less EZR and Excelsior
B Joint Proposal, Appendix 2, Schedule 6, Column A less EZR and Excelsior
C Exhibt ____ (E-RDP-3), Schedule 3, Page 1 of 8, Line 17
D RSS costs allocated by Column C
E Column (D) / Column (A) or Column (B)

REDACTED DOCUMENT

Exhbit 5
Capacity Mitigated
Schedule 1
Page 3 of 3

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID
ALLOCATION OF ESTIMATED RELIABILITY SUPPORT SERVICES COSTS
ANNUAL NET COSTS - TRANSMISSION OPTION

	Design Service Class	12-months ended 3-31-2016 kW Billed (A)	12-months ended 3-31-2016 kWh Sales (B)	Transmission Plant Allocator (C)	Allocation of Estimated RSS Costs (D)	2018 Surcharge Rate (E)	2019	2020	2021	2022	2023	2024	2025	2026	2027
1	SC1	-	11,148,494,696	42 67%	$4,479,429	$ 0 00040	$ 0 00040	$ 0 00040	$ 0 00039	$ 0 00039	$ 0 00039	$ 0 00038	$ 0 00038	$ 0 00038	$ 0 00038
2	SC1C	-	357,847,234	1 00%	$104,978	$ 0 00029	$ 0 00029	$ 0 00029	$ 0 00029	$ 0 00028	$ 0 00028	$ 0 00028	$ 0 00028	$ 0 00028	$ 0 00027
3	SC2ND	-	653,354,732	2 68%	$281,342	$ 0 00043	$ 0 00043	$ 0 00042	$ 0 00042	$ 0 00042	$ 0 00041	$ 0 00041	$ 0 00041	$ 0 00041	$ 0 00040
4	SC2D	15,110,754		14 55%	$1,527,436	$ 0 10	$ 0 10	$ 0 10	$ 0 10	$ 0 10	$ 0 10	$ 0 10	$ 0 10	$ 0 10	$ 0 09
	SC3														
5	Secondary	10,832,314		13.04%	$1,368,918	$ 0 13	$ 0 13	$ 0 12	$ 0 12	$ 0 12	$ 0 12	$ 0 12	$ 0 12	$ 0 12	$ 0 12
6	Primary	4,487,194		5.10%	$535,390	$ 0 12	$ 0 12	$ 0 12	$ 0 12	$ 0 12	$ 0 11	$ 0 11	$ 0 11	$ 0 11	$ 0 11
7	Transmission	1,555,433		1.30%	$136,472	$ 0 09	$ 0 09	$ 0 09	$ 0 09	$ 0 09	$ 0 08	$ 0 08	$ 0 08	$ 0 08	$ 0 08
8	Total	16,874,941	-	19.44%	$2,040,780										
	SC3A														
9	Secondary														
10	Primary	2,684,371		3.19%	$334,881	$ 0 12	$ 0 12	$ 0 12	$ 0 12	$ 0 12	$ 0 12	$ 0 12	$ 0 12	$ 0 12	$ 0 12
11	Subtransmission	3,704,085		4.06%	$426,212	$ 0 12	$ 0 11	$ 0 11	$ 0 11	$ 0 11	$ 0 11	$ 0 11	$ 0 11	$ 0 11	$ 0 11
12	Transmission	12,715,606		12.39%	$1,300,683	$ 0 10	$ 0 10	$ 0 10	$ 0 10	$ 0 10	$ 0 10	$ 0 10	$ 0 10	$ 0 10	$ 0 10
13	Total	19,104,062	-	19.64%	$2,061,776										
14	Total PSC 220				$10,495,742										
	Street and Highway Lighting														
15	SC1	-	23,665,889		$245	$ 0 00001	$ 0 00001	$ 0 00001	$ 0 00001	$ 0 00001	$ 0 00001	$ 0 00001	$ 0 00001	$ 0 00001	$ 0 00001
16	SC2/5	-	159,398,607		$1,647	$ 0 00001	$ 0 00001	$ 0 00001	$ 0 00001	$ 0 00001	$ 0 00001	$ 0 00001	$ 0 00001	$ 0 00001	$ 0 00001
17	SC3/6	-	9,219,028		$95	$ 0 00001	$ 0 00001	$ 0 00001	$ 0 00001	$ 0 00001	$ 0 00001	$ 0 00001	$ 0 00001	$ 0 00001	$ 0 00001
18	SC4	-	10,911,329		$113	$ 0 00001	$ 0 00001	$ 0 00001	$ 0 00001	$ 0 00001	$ 0 00001	$ 0 00001	$ 0 00001	$ 0 00001	$ 0 00001
19	Total PSC 214	-	203,194,853	0 02%	$2,100		$ 2,084	$ 2,069	$ 2,053	$ 2,038	$ 2,023	$ 2,009	$ 1,994	$ 1,980	$ 1,966
20	Total PSC 220/214			100 00%	$10,497,841		$ 10,419,721	$ 10,342,565	$ 10,266,393	$ 10,191,228	$ 10,117,091	$ 10,044,005	$ 9,971,994	$ 9,901,081	$ 9,831,290

A Joint Proposal, Appendix 2, Schedule 6, Column A less EZR and Excelsior
B Joint Proposal, Appendix 2, Schedule 6, Column A less EZR and Excelsior
C Exhibt ____ (E-RDP-3), Schedule 3, Page 1 of 8, Line 17
D RSS costs allocated by Column C
E Column (D) / Column (A) or Column (B)

REPOWERING OPTION 1
BILL IMPACTS

SC1

	600 kWh	without RSS	with RSS									
		2018	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]			[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

MFC	
Uncollectible	2.340%
WC	0.363%
Credit and Collections	0.00063
Electric Supply Procurement	0.0001

REPOWERING OPTION 1
BILL IMPACTS

SC2ND

1500 kWh

		without RSS	with RSS									
		2018	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

MFC	
Uncollectible	2.340%
WC	0.363%
Credit and Collections	0.0006
Electric Supply Procurement	0.0001

SC2D

7,200 kWh
25 kW

		without RSS	with RSS									
		2018	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

MFC	
Uncollectible	0.290%
WC	0.363%
Credit and Collections	0.00006
Electric Supply Procurement	0.0001

REDACTED DOCUMENT
REPOWERING OPTION 1
BILL IMPACTS

SC3 Primary

			without RSS	with RSS									
216,000	kWh												
500	kW		2018	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Customer Charge			$436 70	$436 70	$436 70	$436 70	$436 70	$436 70	$436 70	$436 70	$436 70	$436 70	$436 70
[redacted]		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]			[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]			[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

MFC	
Uncollectible	0 290%
WC	0 363%
Credit and Collections	0 00006
Electric Supply Procurer	0 0001

REDACTED DOCUMENT
REPOWERING OPTION 1
BILL IMPACTS

SC3A Transmission			without RSS	with RSS									
	2,304,000	kWh	2018	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
	4,000	kW											
[redacted]			[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]			[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]			[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

MFC	
Uncollectible	0 290%
WC	0 363%
Credit and Collection	0 00006
Electric Supply Procu	0 0001

REDACTED DOCUMENT
REPOWERING OPTION 2
BILL IMPACTS

SC1

600 kWh		without RSS	with RSS									
		2018	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

MFC	
Uncollectible	2.340%
WC	0.363%
Credit and Collections	0.00063
Electric Supply Procurement	0.0001

REDACTED DOCUMENT

REPOWERING OPTION 2

BILL IMPACTS

SC2ND

1500 kWh	without RSS	with RSS									
	2018	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027

[redacted]

MFC	
Uncollectible	2.340%
WC	0.363%
Credit and Collections	0.0006
Electric Supply Procurement	0.0001

SC2D

7,200 kWh
25 kW

		without RSS	with RSS									
		2018	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
[redacted]		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]						[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]						[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]						[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]						[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]						[redacted]	[redacted]	[redacted]	[redacted]
[redacted]												
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]			[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]			[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

MFC	
Uncollectible	0 290%
WC	0 363%
Credit and Collections	0 00006
Electric Supply Procurement	0 0001

SC3 Primary

		without RSS	with RSS									
216,000 kWh												
500 kW		2018	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

MFC	
Uncollectible	0 290%
WC	0 363%
Credit and Collections	0 00006
Electric Supply Procurer	0 0001

REDACTED DOCUMENT
REPOWERING OPTION 2
BILL IMPACTS

SC3A Transmission		without RSS	with RSS									
		2018	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
2,304,000	kWh											
4,000	kW											
Customer Charge		$3,500 00	$3,500 00	$3,500 00	$3,500 00	$3,500 00	$3,500 00	$3,500 00	$3,500 00	$3,500 00	$3,500 00	$3,500 00
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

MFC	
Uncollectible	0 290%
WC	0 363%
Credit and Collectior	0 00006
Electric Supply Procı	0 0001

REDACTED DOCUMENT
TRANSMISSION UPGRADES
BILL IMPACTS

SC1

600 kWh		without RSS	with RSS									
		2018	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Customer Charge		$17.00	$17.00	$17.00	$17.00	$17.00	$17.00	$17.00	$17.00	$17.00	$17.00	$17.00
T&D Energy Charge	kWh x	$0.04758	$0.04758	$0.04758	$0.04758	$0.04758	$0.04758	$0.04758	$0.04758	$0.04758	$0.04758	$0.04758
Deferral Recovery	kWh x	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
RSS	kWh x	$0.00000	$0.00040	$0.00040	$0.00040	$0.00039	$0.00039	$0.00039	$0.00038	$0.00038	$0.00038	$0.00038
Legacy Transition Charge	kWh x	$0.00151	$0.00151	$0.00163	$0.00161	$0.00184	$0.00125	$0.00119	$0.00092	$0.00103	$0.00017	$0.00008
Electricity Supply Rate Mechanism	kWh x	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
Commodity Energy Charge	kWh x	$0.07266	$0.07266	$0.07552	$0.07677	$0.08051	$0.08333	$0.08624	$0.08926	$0.09239	$0.09562	$0.09897
Transmission Revenue Adjustment Charge	kWh x	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
Systems Benefits Charge	kWh x	$0.00551	$0.00551	$0.00551	$0.00551	$0.00551	$0.00551	$0.00551	$0.00551	$0.00551	$0.00551	$0.00551
Incremental State Assessment Surcharge	kWh x	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
Merchant Function Charge	kWh x	$0.00269	$0.00269	$0.00277	$0.00281	$0.00291	$0.00298	$0.00306	$0.00314	$0.00323	$0.00331	$0.00341
NYPA Hydro Benefit Reconcilation Charge	kWh x	($0.00220)	($0.00220)	($0.00227)	($0.00229)	($0.00235)	($0.00239)	($0.00244)	($0.00248)	($0.00253)	($0.00258)	($0.00263)
Gross Receipts Tax												
Commodity	Bill /	0.9900	0.9900	0.9900	0.9900	0.9900	0.9900	0.9900	0 9900	0.9900	0.9900	0.9900
Delivery	Bill /	0.9700	0.9700	0.9700	0.9700	0.9700	0.9700	0.9700	0 9700	0.9700	0.9700	0.9700
Delivery		$49.94	$50.19	$50.22	$50 19	$50.29	$49.90	$49.84	$49.63	$49.67	$49.11	$49.02
Commodity		$45.67	$45.67	$47.45	$48 23	$50.55	$52.31	$54.12	$56.00	$57.95	$59.96	$62.04
		$95.61	$95.86	$97.67	$98.42	$100.85	$102.21	$103.96	$105.64	$107.62	$109.07	$111.06
Delivery Bill Impact			0.50%	0.06%	-0.05%	0.20%	-0.78%	-0.12%	-0.41%	0.08%	-1 14%	-0.19%
Total Bill Impact			0.26%	1.89%	0.77%	2.46%	1.35%	1.72%	1.61%	1.88%	1.34%	1.82%
Annual Delivery Bill Change			$ 2.98	$ 0.39	$ (0.30)	$ 1.21	$ (4.73)	$ (0.74)	$ (2.45)	$ 0.49	$ (6.79)	$ (1 12)
Annual Commodity Bill Change			$ -	$ 21.33	$ 9 37	$ 27.89	$ 21.05	$ 21.78	$ 22.55	$ 23.34	$ 24.15	$ 25.00
Annual Total Bill Changes			$ 2.98	$ 21.72	$ 9.07	$ 29.10	$ 16.31	$ 21.04	$ 20.10	$ 23.83	$ 17.37	$ 23.88

MFC	
Uncollectible	2.340%
WC	0.363%
Credit and Collections	0.00063
Electric Supply Procurement	0.0001

REDACTED DOCUMENT
TRANSMISSION UPGRADES
BILL IMPACTS

SC2ND

1500 kWh		without RSS	with RSS									
		2018	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Customer Charge		$21.02	$21.02	$21.02	$21.02	$21.02	$21.02	$21.02	$21.02	$21.02	$21.02	$21.02
T&D Energy Charge	kWh x	$0.05696	$0.05696	$0.05696	$0.05696	$0.05696	$0.05696	$0.05696	$0.05696	$0.05696	$0.05696	$0.05696
Deferral Recovery	kWh x	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
RSS	kWh x	$0.00000	$0.00043	$0.00043	$0.00042	$0.00042	$0.00042	$0.00041	$0.00041	$0.00041	$0.00041	$0.00040
Legacy Transition Charge	kWh x	$0.00151	$0.00151	$0.00163	$0.00161	$0.00184	$0.00125	$0.00119	$0.00092	$0.00103	$0.00017	$0.00008
Electricity Supply Rate Mechanism	kWh x	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
Commodity Energy Charge	kWh x	$0.07702	$0.07702	$0.08000	$0.08105	$0.08496	$0.08793	$0.09101	$0.09419	$0.09749	$0.10090	$0.10443
Transmission Revenue Adjustment Charge	kWh x	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
Systems Benefits Charge	kWh x	$0.00551	$0.00551	$0.00551	$0.00551	$0.00551	$0.00551	$0.00551	$0.00551	$0.00551	$0.00551	$0.00551
Incremental State Assessment Surcharge	kWh x	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
Merchant Function Charge	kWh x	$0.00281	$0.00281	$0.00289	$0.00292	$0.00303	$0.00311	$0.00319	$0.00328	$0.00337	$0.00346	$0.00355
Gross Receipts Tax												
Commodity	Bill /	0.9900	0.9900	0.9900	0.9900	0.9900	0.9900	0.9900	0 9900	0.9900	0.9900	0.9900
Delivery	Bill /	0.9900	0.9900	0.9900	0.9900	0.9900	0.9900	0.9900	0 9900	0.9900	0.9900	0.9900
Delivery		$ 118.17	$ 118.82	$ 119.00	$ 118.97	$ 119.31	$ 118.41	$ 118.32	$ 117.90	$ 118.07	$ 116.76	$ 116.61
Commodity		$ 120.95	$ 120.95	$ 125.60	$ 127.23	$ 133.31	$ 137.94	$ 142.73	$ 147.68	$ 152.81	$ 158.12	$ 163.62
		$ 239.12	$ 239.77	$ 244.61	$ 246.20	$ 252.62	$ 256.34	$ 261.05	$ 265.58	$ 270.88	$ 274.88	$ 280.23
Delivery Bill Impact			0.55%	0 15%	-0.03%	0.28%	-0.75%	-0.07%	-0.36%	0.15%	-1.11%	-0.13%
Total Bill Impact			0.27%	2.01%	0.65%	2.60%	1.48%	1.84%	1.73%	2.00%	1.48%	1.94%
Annual Delivery Bill Change			$ 7.82	$ 2.18	$ (0.38)	$ 4.02	$ (10.80)	$ (0.99)	$ (5.13)	$ 2.10	$ (15.71)	$ (1.79)
Annual Commodity Bill Change			$ -	$ 55.80	$ 19.55	$ 72.93	$ 55.53	$ 57.47	$ 59.48	$ 61.56	$ 63.72	$ 65.95
Annual Total Bill Changes			$ 7.82	$ 57.97	$ 19.17	$ 76.95	$ 44.73	$ 56.48	$ 54.35	$ 63.66	$ 48.01	$ 64.15

MFC	
Uncollectible	2.340%
WC	0.363%
Credit and Collections	0.0006
Electric Supply Procurement	0.0001

SC2D

			without RSS	with RSS									
7,200 kWh													
25 kW			2018	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Customer Charge			$52 52	$52 52	$52 52	$52 52	$52 52	$52 52	$52 52	$52 52	$52 52	$52 52	$52 52
T&D Demand Charge		kW x	$10 27	$10 27	$10 27	$10 27	$10 27	$10 27	$10 27	$10 27	$10 27	$10 27	$10 27
Deferral Recovery		kW x	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00
RSS		kW x	$0 00	$0 10	$0 10	$0 10	$0 10	$0 10	$0 10	$0 10	$0 10	$0 10	$0 09
Legacy Transition Charge		kWh x	$0 00151	$0 00151	$0 00163	$0 00161	$0 00184	$0 00125	$0 00119	$0 00092	$0 00103	$0 00017	$0 00008
Commodity Energy Charge		kWh x	$0 07091	$0 07091	$0 07374	$0 07498	$0 07867	$0 08142	$0 08427	$0 08722	$0 09027	$0 09343	$0 09670
Transmission Revenue Adjustment Charge		kWh x	$0 00000	$0 00000	$0 00000	$0 00000	$0 00000	$0 00000	$0 00000	$0 00000	$0 00000	$0 00000	$0 00000
Systems Benefits Charge		kWh x	$0 00551	$0 00551	$0 00551	$0 00551	$0 00551	$0 00551	$0 00551	$0 00551	$0 00551	$0 00551	$0 00551
Incremental State Assessment Surcharge		kW x	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00
Merchant Function Charge		kWh x	$0 00062	$0 00062	$0 00064	$0 00065	$0 00067	$0 00069	$0 00071	$0 00073	$0 00075	$0 00077	$0 00079
Gross Receipts Tax													
Commodity		Bill /	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900
Delivery		Bill /	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900
Delivery			$ 363 44	$ 365 99	$ 366 86	$ 366 72	$ 368 33	$ 364 01	$ 363 62	$ 361 57	$ 362 42	$ 356 14	$ 355 42
Commodity			$ 520 27	$ 520 27	$ 540 98	$ 550 05	$ 577 03	$ 597 18	$ 618 04	$ 639 63	$ 661 98	$ 685 11	$ 709 05
			$ 883 72	$ 886 27	$ 907 84	$ 916 76	$ 945 35	$ 961 19	$ 981 66	$ 1,001 21	$ 1,024 39	$ 1,041 24	$ 1,064 47
	Delivery Bill Impact			0 70%	0 24%	-0 04%	0 44%	-1 17%	-0 11%	-0 56%	0 23%	-1 73%	-0 20%
	Total Bill Impact			0 29%	2 43%	0 98%	3 12%	1 68%	2 13%	1 99%	2 32%	1 64%	2 23%
	Annual Delivery Bill Change			$ 30 63	$ 10 44	$ (1 79)	$ 19 36	$ (51 78)	$ (4 69)	$ (24 59)	$ 10 11	$ (75 34)	$ (8 56)
	Annual Commodity Bill Change			$ -	$ 248 41	$ 108 86	$ 323 74	$ 241 86	$ 250 33	$ 259 09	$ 268 16	$ 277 54	$ 287 26
	Annual Total Bill Changes			$ 30 63	$ 258 86	$ 107 08	$ 343 10	$ 190 08	$ 245 64	$ 234 50	$ 278 26	$ 202 20	$ 278 70

MFC	
Uncollectible	0 290%
WC	0 363%
Credit and Collections	0 00006
Electric Supply Procurement	0 0001

REDACTED DOCUMENT
TRANSMISSION UPGRADES
BILL IMPACTS

SC3 Primary

		without RSS	with RSS									
216,000 kWh												
500 kW		2018	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Customer Charge		$436 70	$436 70	$436 70	$436 70	$436 70	$436 70	$436 70	$436 70	$436 70	$436 70	$436 70
T&D Demand Charge	kW x	$8 15	$8 15	$8 15	$8 15	$8 15	$8 15	$8 15	$8 15	$8 15	$8 15	$8 15
Deferral Recovery	kW x	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00
RSS	kW x	$0 00	$0 12	$0 12	$0 12	$0 12	$0 12	$0 11	$0 11	$0 11	$0 11	$0 11
Legacy Transition Charge	kWh x	$0 00151	$0 00151	$0 00163	$0 00161	$0 00184	$0 00125	$0 00119	$0 00092	$0 00103	$0 00017	$0 00008
Commodity Energy Charge	kWh x	$0 06452	$0 06452	$0 06715	$0 06934	$0 07281	$0 07536	$0 07800	$0 08073	$0 08355	$0 08648	$0 08950
Transmission Revenue Adjustment Charge	kWh x	$0 00000	$0 00000	$0 00000	$0 00000	$0 00000	$0 00000	$0 00000	$0 00000	$0 00000	$0 00000	$0 00000
Systems Benefits Charge	kWh x	$0 00551	$0 00551	$0 00551	$0 00551	$0 00551	$0 00551	$0 00551	$0 00551	$0 00551	$0 00551	$0 00551
Incremental State Assessment Surcharge	kW x	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00
Merchant Function Charge	kWh x	$0 00058	$0 00058	$0 00060	$0 00061	$0 00064	$0 00065	$0 00067	$0 00069	$0 00071	$0 00072	$0 00074
Gross Receipts Tax												
Commodity	Bill /	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900
Delivery	Bill /	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900

	without RSS 2018	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Delivery	$ 6,088 70	$ 6,148 96	$ 6,175 19	$ 6,170 84	$ 6,219 35	$ 6,090 01	$ 6,078 40	$ 6,017 03	$ 6,042 41	$ 5,854 16	$ 5,832 87
Commodity	$ 14,203 71	$ 14,203 71	$ 14,780 98	$ 15,263 04	$ 16,024 66	$ 16,584 30	$ 17,163 53	$ 17,763 03	$ 18,383 52	$ 19,025 72	$ 19,690 40
	$ 20,292 41	$ 20,352 67	$ 20,956 17	$ 21,433 88	$ 22,244 01	$ 22,674 31	$ 23,241 93	$ 23,780 06	$ 24,425 93	$ 24,879 88	$ 25,523 26
Delivery Bill Impact		0 99%	0 43%	-0 07%	0 79%	-2 08%	-0 19%	-1 01%	0 42%	-3 12%	-0 36%
Total Bill Impact		0 30%	2 97%	2 28%	3 78%	1 93%	2 50%	2 32%	2 72%	1 86%	2 59%
Annual Delivery Bill Change		$ 723 12	$ 314 74	$ (52 20)	$ 582 13	$ (1,552 05)	$ (139 31)	$ (736 46)	$ 304 52	$ (2,258 93)	$ (255 55)
Annual Commodity Bill Change		$ -	$ 6,927 27	$ 5,784 71	$ 9,139 44	$ 6,715 70	$ 6,950 75	$ 7,194 02	$ 7,445 81	$ 7,706 42	$ 7,976 14
Annual Total Bill Changes		$ 723 12	$ 7,242 01	$ 5,732 51	$ 9,721 57	$ 5,163 65	$ 6,811 44	$ 6,457 56	$ 7,750 33	$ 5,447 49	$ 7,720 59

MFC

Uncollectible	0 290%
WC	0 363%
Credit and Collections	0 00006
Electric Supply Procurement	0 0001

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TRANSMISSION UPGRADES
BILL IMPACTS

SC3A Transmission		without RSS	with RSS									
2,304,000 kWh		2018	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
4,000 kW												
Customer Charge		$3,500 00	$3,500 00	$3,500 00	$3,500 00	$3,500 00	$3,500 00	$3,500 00	$3,500 00	$3,500 00	$3,500 00	$3,500 00
T&D Demand Charge	kW x	$2 84	$2 84	$2 84	$2 84	$2 84	$2 84	$2 84	$2 84	$2 84	$2 84	$2 84
Deferral Recovery	kW x	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00
RSS	kW x	$0 00	$0 10	$0 10	$0 10	$0 10	$0 10	$0 10	$0 10	$0 10	$0 10	$0 10
Legacy Transition Charge	kWh x	$0 00151	$0 00151	$0 00163	$0 00161	$0 00184	$0 00125	$0 00119	$0 00092	$0 00103	$0 00017	$0 00008
Commodity Energy Charge	kWh x	$0 06047	$0 06047	$0 06297	$0 06465	$0 06791	$0 07028	$0 07274	$0 07529	$0 07793	$0 08065	$0 08348
Transmission Revenue Adjustment Charge	kWh x	$0 00000	$0 00000	$0 00000	$0 00000	$0 00000	$0 00000	$0 00000	$0 00000	$0 00000	$0 00000	$0 00000
Systems Benefits Charge	kWh x	$0 00551	$0 00551	$0 00551	$0 00551	$0 00551	$0 00551	$0 00551	$0 00551	$0 00551	$0 00551	$0 00551
Incremental State Assessment Surcharge	kW x	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00	$0 00
Merchant Function Charge	kWh x	$0 00055	$0 00055	$0 00057	$0 00058	$0 00060	$0 00062	$0 00064	$0 00065	$0 00067	$0 00069	$0 00071
Gross Receipts Tax												
Commodity	Bill /	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900
Delivery	Bill /	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900	0 9900
Delivery		$ 31,345	$ 31,759	$ 32,040	$ 31,995	$ 32,514	$ 31,137	$ 31,014	$ 30,361	$ 30,634	$ 28,627	$ 28,402
Commodity		$ 142,028	$ 142,028	$ 147,868	$ 151,805	$ 159,444	$ 165,012	$ 170,774	$ 176,738	$ 182,911	$ 189,300	$ 195,912
		$ 173,374	$ 173,787	$ 179,908	$ 183,801	$ 191,959	$ 196,148	$ 201,789	$ 207,100	$ 213,545	$ 217,927	$ 224,314
Delivery Bill Impact			1 32%	0 89%	-0 14%	1 62%	-4 24%	-0 39%	-2 11%	0 90%	-6 55%	-0 79%
Total Bill Impact			0 24%	3 52%	2 16%	4 44%	2 18%	2 88%	2 63%	3 11%	2 05%	2 93%
Annual Delivery Bill Change			$ 4,959 53	$ 3,377 71	$ (536 52)	$ 6,229 42	$ (16,535 49)	$ (1,466 52)	$ (7,836 36)	$ 3,267 11	$ (24,076 65)	$ (2,707 52)
Annual Commodity Bill Change			$ -	$ 70,074 57	$ 47,248 53	$ 91,670 45	$ 66,810 24	$ 69,148 60	$ 71,568 80	$ 74,073 71	$ 76,666 28	$ 79,349 60
Annual Total Bill Changes			$ 4,959 53	$ 73,452 28	$ 46,712 01	$ 97,899 87	$ 50,274 75	$ 67,682 08	$ 63,732 43	$ 77,340 81	$ 52,589 64	$ 76,642 08

MFC	
Uncollectible	0 290%
WC	0 363%
Credit and Collections	0 00006
Electric Supply Procurement	0 0001

Exhibit 6

REDACTED DOCUMENT

PA Consulting Group

National Grid

Analysis of Dunkirk Repowering Options

Final Report

May 15, 2013

REDACTED DOCUMENT

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Document reference:

Executive summary

PA Consulting Group (PA) has been hired by National Grid to review three repowering options for the Dunkirk power plant proposed by NRG Energy (NRG). Additionally, National Grid requested that PA review the "Economic Impact Analysis" report completed by Longwood Energy Group (LEG), which assessed one of these options.

The three options proposed by NRG are:

- Option 1: Refuel Dunkirk Unit 2 on natural gas by mid-2015 and build a new 422MW combined cycle at the Dunkirk site (interconnected to the 230kV network) by mid-2017
- Option 2: Refuel Dunkirk Units 2, 3 and 4 using natural gas by mid-2015. The total capacity of the retrofitted units is projected to be 455MW
- Option 3: Replace the existing Dunkirk Units by 285MW of new gas-fired peaking capacity. National Grid and PA agreed that Option 3 would not be a viable option therefore PA did not include an assessment of Option 3 in this report.

PA has evaluated Options 1 and 2 against a Reference Case. The Reference Case reflects the retirement of all the units at the Dunkirk site at the end of 2014 and includes reliability transmission upgrades recommended by National Grid in the event all the Dunkirk units are retired.

For this analysis, PA focused on the impact of each option on production costs[1]. Production costs are the costs paid collectively by the electricitysector, excluding or netting out transfer payments made between market participants.

PA has generally presented its results on a 2013 Net Present Value (NPV) basis.[2] LEG presented it results, which are generally annual averages, in 2012 dollars and PA has presented similar results in 2012 dollars and for ease of comparison.[3]

- Both Option 1 and Option 2 result in an increase in total production costs across the New York Independent System Operator (NYISO) area. The production costs increase over the study period (calendar years 2015-2025) by $122M in Option 1 and $430M in Option 2 respectively. This is equivalent to annual average increases of $16M and $55M for Options 1 and 2, respectively, in 2012 dollars.
- As shown in the following figures, the benefits of the repowering get partially redistributed to neighboring regions, such as the Pennsylvania New Jersey Maryland Interconnection (PJM).
  - The production costs significantly increase in Zone A for both options (due to the addition of new generating capacity) and the savings observed in the other NY zones are not large enough to cover the increase observed in Zone A.

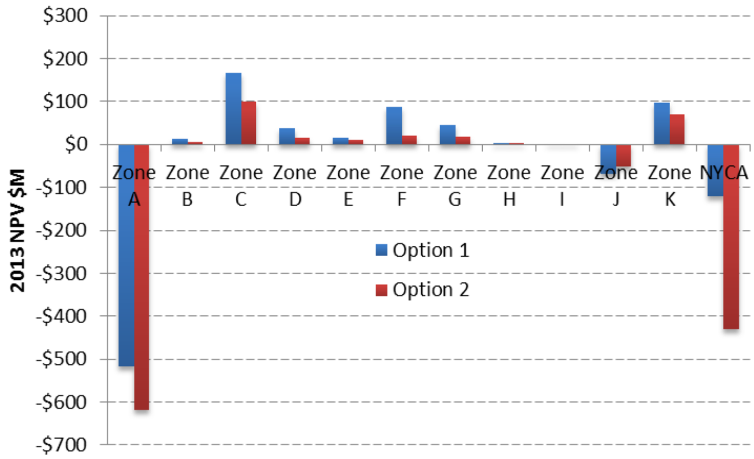
---

[1] Production costs include fuel and other variable costs, start-up costs and emissions costs.

[2] PA used a discount rate of 7.36%, as reported in the 2011 CARIS Study, which represents the weighted average of the after-tax Weighted Average Cost of Capital (WACC) for the New York Transmission Operators.

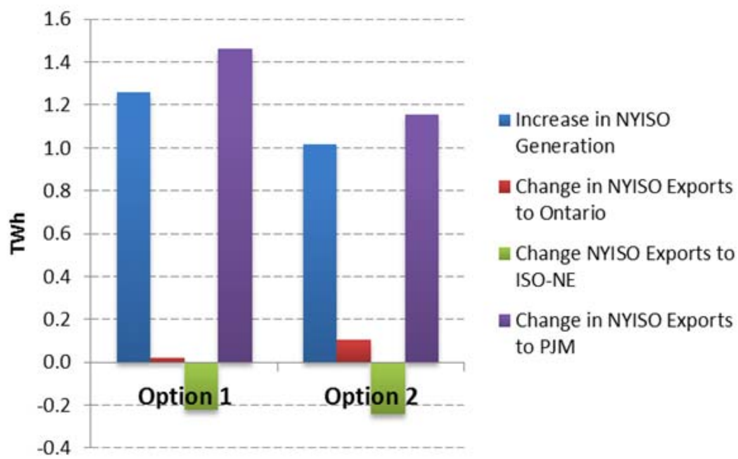
[3] Figures in "2012 dollars" are computed with a uniform 2.7% annual deflator.

Production cost savings relative to the Reference Case: Option 1 vs. Option 2[4]



– There is a large increase in energy flows from NYISO to PJM in Option 1 relative to the Reference Case. There are significant import/export capabilities with PJM in the Dunkirk area which facilitate energy transfers from the new Dunkirk combined cycle to PJM, while intrastate transfers to zones G-K are constrained. This highlights the economic importance of location in a repowering decision.

Impact of the increase in NYISO generation in Option 1 and Option 2 on inter-regional flows (annual average)[5]

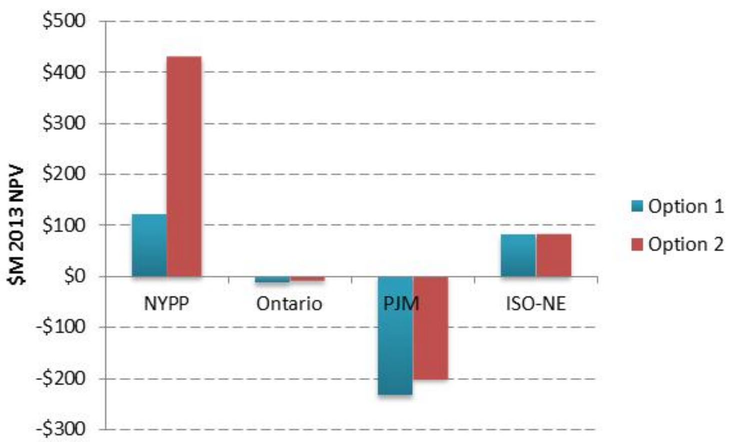


– NYISO does not capture the full extent of the repowering benefits. There are significant production cost reductions in PJM and, to a small extent, Ontario, that are facilitated by cost increases in NYISO and ISO-NE.

[4] Negative cost savings represent cost increases.

[5] A negative change in exports represents an increase in imports.

Changes in production cost for NYISO and neighboring regions



PA also assessed the impact of Option 1 and Option 2 on Locational Marginal Prices (LMPs[6]) costs, Installed Capacity (ICAP) payments[7] and emissions. The analysis does not consider how generators respond (i.e. retirements or mothballing) to the concomitant reduction in their revenues. In addition, PA did not assume that any mitigation measures would be applied to the repowering options in energy or capacity markets.

- Option 1 yields a total of $97M in LMP cost savings as opposed to a $7M increase in LMP costs for Option 2 over the study period (2013 NPV). This difference in LMPcost savings to load reflects the greater efficiency of the new 422MW combined cycle in Option 1 relative to the retrofitted Dunkirk units 3 and 4 in Option 2
- The total NYISOICAP cost savings associated with Option 1 are estimated at $560M and $841M for Option 2 (2013 NPV). The larger ICAP cost savings observed in Option 2 are due to the timing difference in capacity addition between the two options: similar capacity is added in both options, but the bulk of the capacity under Option 2 is added earlier than in Option 1, resulting in larger present value savings[8]
- In both Options 1 and 2, CO2 emissions increase in NYISO while NOx and SOx emissions drop over the study period. Thanks to the greater efficiency and state of the art emission controls of the new combined cycle, Option 1 yields a smaller increase in CO2 emissions and greater reductions in NOx and SOx emissions relative to Option 2.

PA has compared its findings to those presented in LEG's study: savings in production costs, LMP and ICAP payments as well as in emissions across NYISO are lower in PA's analysis. PA believes that the differences observed with regards to production costs and LMP savings, as well as emissions, are

---

[6] Actual LMPs represent the price of energy and include costs of congestion and marginal losses. Note that the impact of losses is excluded from the LMPs reported by the production cost model used by PA (GE-MAPS). However, marginal losses represent a small fraction of the LMPs, and the LMP differentials between the Reference Case and Options 1 & 2 should provide an accurate indicator of the actual impact on LMPs.

[7] Note that the total LMP and ICAP cost savings presented here have been reduced by 25% to account for savings assumed to beunattainable by load-serving entities exercising long-term energy contracts. This replicates LEG's assumption.

[8] PA did not make any assumptions regarding potential adverse impacts on existing generation or effects on off system ICAP sales or imports.

primarily due to the difference in representing interactions with adjacent electricity markets in the production cost model used by PA (GE-MAPS) and the one used by LEG (Dayzer).

LEG’s model is limited to the NYISO market and makes the further simplifying assumption that "cross-border flows are unaffected by the repowering project". This suggests that NYISO is modeled in isolation and that changes in energy flows between NYISO, PJM, ISO-NE, Ontario and Quebec due to the repowering options are not accounted for.

On the other hand, PA's modeling of the NYISO market incorporated all adjacent markets and accounted for changes in inter-regional flows among those markets adjacent to NYISO and across the Eastern Interconnect. As mentioned previously, the reactions of adjacent markets to changes in the NYISO market effectively redistributed a portion of the benefits (e.g., lower NYISO LMPs) across the neighboring regions. We believe this to be more reflective of actual market behavior.

Consequently, the NYISO production cost, LMPand emissions savings identified in PA's analysis are lower than those outlined in LEG's study.

Furthermore, PA has accounted for New York's New Capacity Zone (NCZ) (which establishes a new locality comprised of NY Zones G, H, I and J expected to be effective in 2014) in its ICAP cost calculations. Generators located in the NCZ are therefore insulated from the rent reductions (or, reduction in producer surplus) attributable to the addition of the Dunkirk capacity in Options 1 and 2. Consequently, the ICAP cost savings observed in PA's analysis are smaller than in LEG's.

Comparison of PA's and LEG's findings

Option 1 - NYISO	PA's Study	LEG's Study
Annual Production Cost Savings 2012 $M[9]	-$16	$28
Annual LMP Cost Savings 2012 $M	$9	$142
Annual ICAP Cost Savings 2012 $M	$50	$159
Wholesale Market Price Reduction ($/MWh)	$0.07	$1.11
CO2 emissions reduction[10]	-0.2%	0.8%
Nox emissions reduction	2.6%	3.2%
Sox emissions reduction	2.6%	3.5%

In addition to the power market analysis, PA was asked to perform a review of literature analyzing the economic impacts associated with large repowering projects in New YorkState. PA reviewed two publicly available economic impact analysis models and compared the model results with those of LEG’s Economic Impact Analysis. The comparison showed that whereas LEG’s estimation for job creation is significantly higher than the two models reviewed, increase in Gross Regional Product (GRP) estimation is in close agreement. One major shortcoming identified by PA is that the LEG analysis did not consider the economic impact on other generators in the region. Reduction in revenues to existing generation may result in job losses, reduced property taxes, and diminished electric system reliability in other parts of the state due to plant closures.

[9] Negative cost savings represent cost increases.

[10] A negative emissions reduction represents an increase in emissions.

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1 Approach

PA has reviewed three repowering options proposed by NRG for the Dunkirk Units as well as the "Economic Impact Analysis" Report completed by LEG which analyzed oneof the options suggested by NRG. PA has assessed the benefits associated with these options based on the production cost, LMPcosts, ICAPpayments and emissions impacts they would yield across the NYISO market and the Niagara Mohawk Service Area[11].

The repowering options are detailed in NRG's response to National Grid's February 19, 2013 Dunkirk Repowering Request For Proposal (RFP), pursuant to the New York Public Service Commission's ("NYPSC") January 18, 2013 Order Instituting Proceeding and Requiring Evaluation of Generation Repowering.

The repowering options proposed by NRG are described inTable 1.1. PA has evaluated these options against a Reference Case. The Reference Case reflects the retirement of all the units at the Dunkirk site at the end of 2014 and includes reliability transmission upgrades recommended by National Grid in the event all the Dunkirk units are retired. These transmission upgrades are identified in Appendix B, Section B.7.

Table 1.1: Description of the Reference Case and NRG's repowering options

Case	New Capacity at Dunkirk Site	Operation of Dunkirk Units	Comment
Reference Case	None	All units retired	Includes the transmission upgrades required to maintain reliability if the Dunkirk units are retired
Option 1	One 422MW Combined Cycle in June 2017	Units 1, 3 and 4 retired Unit 2 retrofitted to use natural gas in June 2015	Does not include the transmission upgrades required to maintain reliability if the Dunkirk units are retired
Option 2	None	Unit 1 retired Units 2, 3 and 4 retrofitted to use natural gas in June 2015	Does not include the transmission upgrades required to maintain reliability if the Dunkirk units are retired
Option 3	285MW of new peaking capacity in June 2017	All units retired	Does not include the transmission upgrades required to maintain reliability if the Dunkirk units are retired

PA and National Grid agreed that Option 3 would not be a viable option since transmission upgrades would be required to ensure system reliability until the new capacity comes online in June 2017, therefore adding significant costs, and because the proposed capacity additions are insufficient to address projected long-term reliability needs in the area. Therefore, PA does not provide an assessment of Option 3 in this report.

[11] The benefits associated with the Niagara Mohawk area have been computed based on the proportion of Niagara Mohawk customers' load relative to the total load of NY Zones A through F.

PA has used the production cost model GE-MAPS (developed by General Electric (GE)) to derive the production cost, LMP cost and emissions savings and its in-house ICAP model to compute the impact on ICAP payments by load associated with each option.

GE-MAPS is a detailed, chronological simulation model that calculates hourly energy prices and power production costs. The model utilizes a detailed representation of the entire transmission network, including individual transmission lines, interfaces, phase-angle regulators, and HVDC lines, and incorporates a solved AC power flow with generation shift factors to calculate the real power flows for each generation dispatch.

Thanks to its detailed representation of generation and transmission system, GE-MAPS iswell suited for studying the impact of resource additions such as the proposed repowering options. In addition, GE-MAPS can account for both inter- and intra-zonal congestion (which are not readily captured in zonal models) as well as changes in inter-regional energy flows[12].

PA's approach to production modeling using the GE-MAPS model consists of four major steps:

1. Assess the accuracy of the model. To assess the accuracy of its GE-MAPS model, PA has run a 2010 backcast focusing on the NYISO area: this backcast consisted of a comparison of the GE-MAPS model outputs to actual energy market characteristics for the year 2010. Details on PA's 2010 backcast are available in Appendix A
2. Update model inputs for the study period. PA's GE-MAPS model has been updated to reflect the latest publicly available forecasts for fuel prices, load, capacity addition and retirements, transmission improvements and imports/exports. PA's input assumptions are detailed in Appendix B
3. Set up runs. The study period has been set to 2015-2025 (full calendar years) and PA has run its GE-MAPS model for 4 distinct years -- 2015, 2018, 2021, and 2025. PA's study period differs from LEG's which starts in 2018 and ends in 2027, and therefore does not capture the impact of the retrofitted Dunkirk Units 2, 3 and 4 (Option 2) in 2015, 2016 and 2017. Overall, PA's study period spans 11 years, compared to 10 years for LEG's study
4. Assess the reasonableness of model outputs. PA completed a qualitative review of the model outputs to ensure that they were appropriately reflecting the market changes projected for the study period.

PA then post processed[13] the GE-MAPS outputs to compute the changes in production costs, LMP costs, ICAP costs and emissions in order to evaluate the proposed repowering options.

In addition to the power market analysis, PA has performed a literature review on the economic impacts associated with large repowering projects in New York State. As part of this task, PA reviewed two publicly available economic impact analysis models and compared the model results with those of LEG’s Economic Impact Analysis.

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[12] Note that the impact of marginal losses on prices is not captured by GE-MAPS. However, marginal losses have much less impact on dispatch than does congestion.

[13] GE-MAPS provides hourly and annual outputs for a large range of parameters such as load, LMPs, generation, etc., at the unit, zonal and pool levels. In addition, it is possible to extract outputs related to transmission line operation, such as hourly flows, congestion costs or binding hours.

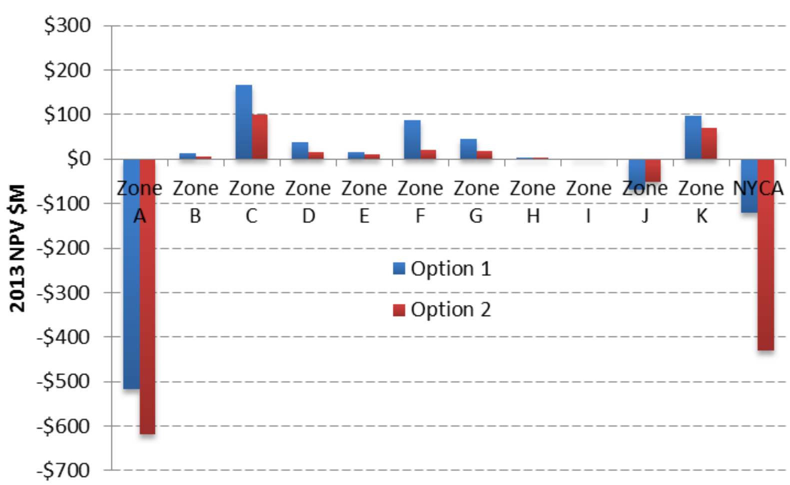
2 Study Results

2.1 Changes in NYISO Production Costs over the Study Period

PA has compared the changes in production costs for generating units located in the NYISO market in Option 1 and Option 2 relative to the Reference Case. Production costs are the costs paid collectively by the electricity sector, excluding or netting out transfer payments made between market participants. They include fuel and other variable costs as well as start-up and emissions costs.

Total production costs over the study period are projected to increase across NYISO in both Option 1 and Option 2 by $122M and $430M respectively, on a 2013 NPV basis[14]. This is equivalent to annual average increases of $16M and $55M for Options 1 and 2, respectively, in 2012 dollars. As shown in Figure 2-1, the production costs significantly increase in Zone A for both options (due to the addition of new generating capacity) and the savings observed in the other NY zones are not large enough to cover the increase observed in Zone A.

Figure 2-1: Production cost savings relative to the Reference Case: Option 1 vs. Option 2[15]



These findings differ from those of LEG's study which shows a reduction in annual production cost of $28M (2012 dollars) for Option 1 across NYISO. PA believes that this is due to differences in geographic scope.

LEG's model includes the simplifying assumption that "cross-border flows are unaffected by the repowering project". This suggests that LEG modeled NYISO in isolation and that it is constrained by fixed cross-border flows. Therefore, the benefits of the repowering project are redistributed across NYISO only, and not across neighboring regions.

---

[14] This difference in the NPV value of the production cost increase between the two cases is primarily due to the timing difference in capacity addition between the two options. Under option 2, the bulk of the capacity is added in June 2015 as opposed to June 2017 in Option 1, therefore increasing the production costs in Zone A starting in 2015, 2 years earlier than in Option 1.

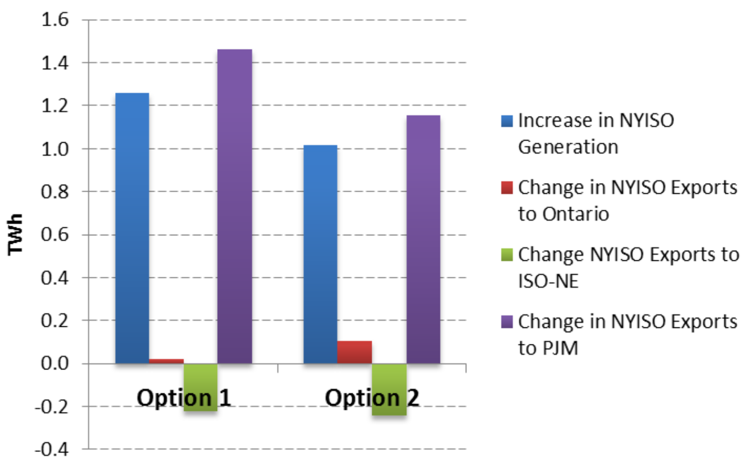
[15] Negative cost savings represent cost increases.

Table 2.1: Production cost savings - PA's vs. LEG's findings[16]

	Annual Average Savings - PA (2012 $M)	Annual Average Savings - LEG (2012 $M)
Option 1	($16)	$28
Option 2	($55)	NA

However, GE-MAPS accounts for changes in inter-regional flows. The GE-MAPS model shows a 1.3GWh annual average increase in energy exports from NYISO West to PJM in Option 1 relative to the Reference Case. There are significant import/export capabilities with PJM and Ontario in the Dunkirk area which facilitate energy transfers from the new Dunkirk combined cycle to these regions, while intrastate transfers to zones G-K are constrained. The total change in flow from NYISO into PJM even exceeds the increase in NYISO generation. Units that would have been occasionally operating to maintain their commitment are instead shut down. This creates the opportunity for additional production in New England that is effectively wheeled through New York. Consequently, the repowering benefits (production costs and LMP costs - see section 2.2) identified in this analysis across NYISO are lower than those reported in LEG's study. The impact of the repowering under Option 1 and 2 on NYISO total generation and on inter-regional flows between NYISO, PJM, ISO-NE and Ontario is displayed onFigure 2-2[17].

Figure 2-2: Impact of the increase in NYISO generation in Option 1 and Option 2 on inter-regional flows (study period annual average)[18]



The increase in energy flows into PJM redistributes the benefits of the repowering not only across NYISO but across the neighboring regions. There are significant production cost reductions in PJM and, to a small extent, Ontario, that are facilitated by cost increases in NYISO and ISO-NE. This is shown in Figure 2-3. If the repowered plant's location were different a greater share of the cost reduction benefits might have remained in New York.

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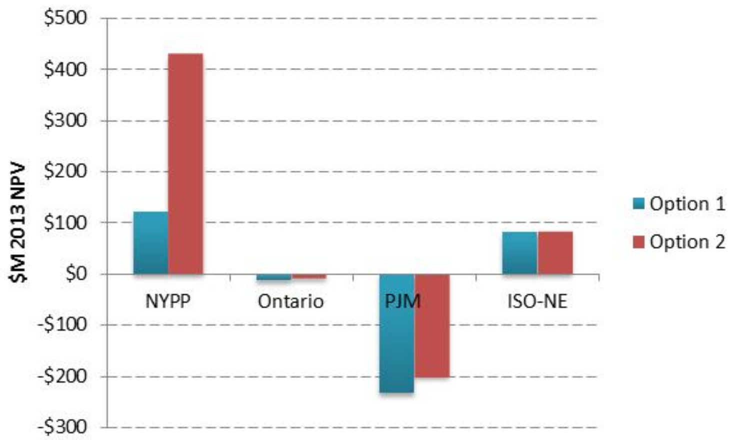
[16] Negative cost savings represent cost increases.

[17] PA assumed that energy flows from Hydro Quebec to NYISO would not be impacted by the repowering.

[18] A negative change in exports represents an increase in imports.

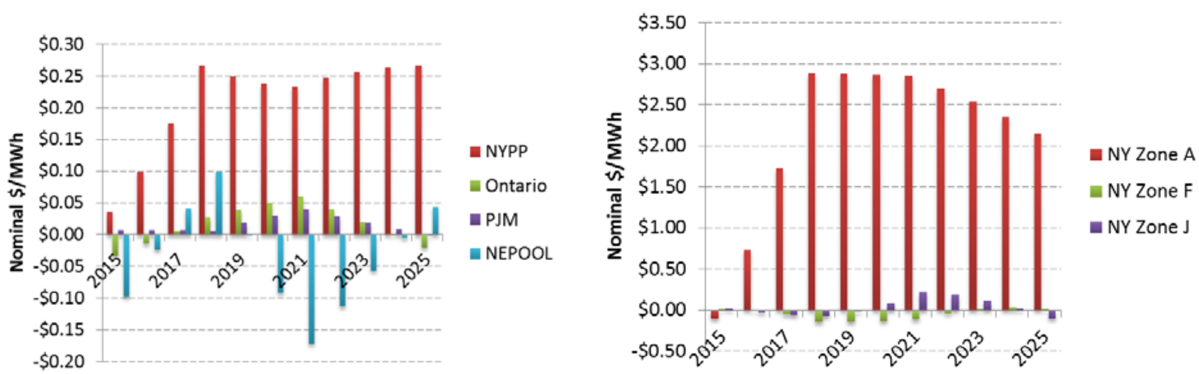
Figure 2-3: Changes in production cost for NYISO and neighboring regions



The higher production costs in Option 2 are attributed to the "must-run" status of the refueled Dunkirk units, absent the transmission upgrades of the Reference Case. NRG's RFP response did not project any efficiency improvements associated with the refueling.

While the total production costs increase in NYISO, the annual average production costs (ratio of total production costs and energy produced, expressed in $/MWh) decrease in Option 1, which reflects the efficiency of the new Combined Cycle[19].

Figure 2-4: Decrease in annual average production costs ($/MWh) - Option 1[20]



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[19] The GE-MAPS outputs show that the new Combined Cycle is running at 78%, 73% and 71% capacity factor in 2018, 2021 and 2025 respectively.

[20] Negative cost savings represent cost increases.

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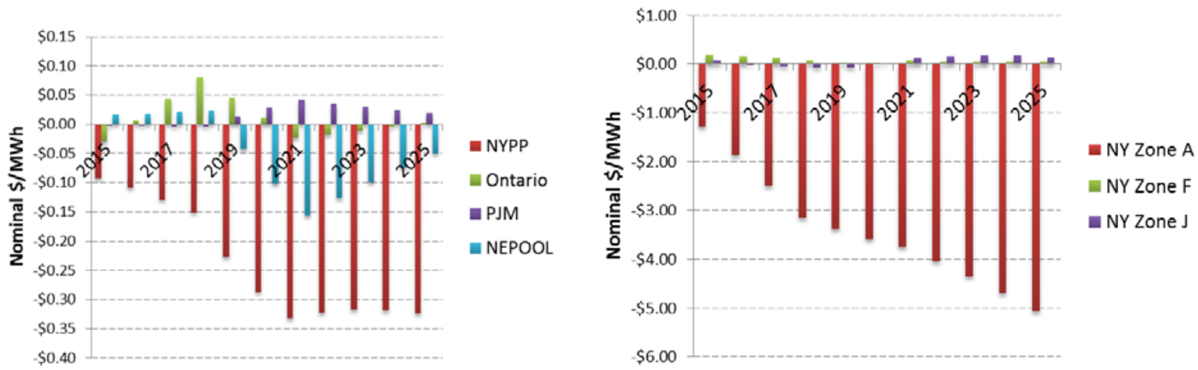
Figure 2-5: Decrease in annual average production costs ($/MWh) - Option 2[21]



The annual production costs decrease by an average of $0.21/MWh over the study period in NYISO and $2.14/MWh in NY Zone A. The benefits of the repowering under Option 1 are also redistributed to Ontario and PJM as demonstrated by the drop in annual average production costs for these regions shown in Figure 2-4 as well as the increase in energy flows from NYISO to PJM and the reduction of flows from Ontario to NYISO displayed onFigure 2-2.

An increase of average production costs in NYISO and NY Zone A is observed under Option 2. PA used the heat rates of the old coal fired Dunkirk units for the refueled Dunkirk 2, 3 and 4 in its GE-MAPS model. Therefore, the refueled units are less efficient than the bulk of the base load units operating in NYISO in 2015 and beyond, which causes the average annual productions costs to increase.

2.2 Changes in LMP Costs over the Study Period

Option 1 includes the addition of a new, clean and efficient 422MW combined cycle which is expected to decrease LMPs by displacing higher-cost generation. The same trend is expected for Option 2 but to a lesser extent since the repowered Dunkirk units (2, 3 and 4) would be less efficient than the new combined cycle considered in Option 1 due to higher heat rates.

PA has compared the LMP cost of Option 1 and Option 2 relative to the Reference Case by computing the product of the hourly zonal energy price by the hourly demand for every hour in the year. Furthermore, PA analyzed the impact of the repowering options on both NYISO and National Grid customers (customers within the Niagara Mohawk area).

PA's analysis does not consider how other market participants will respond (i.e. retirements or mothballing) to the fact that owners of generating units will see an equal and off-setting reduction in their revenues. Nor does it account for mitigation measures that would affect prices but not production costs.

The LMP cost savings are larger for Option 1 than for Option 2[22]:

- Across the NYISO area, Option 1 yields a total of $97M in LMP cost savings as opposed to a $7M LMP cost increase for Option 2 (2013 NPV) over the entire study period. This translates into $9M in

---

[21] Negative cost savings represent cost increases.

[22] Note that the total LMP cost savings presented here have been reduced by 25% to account for savings assumed to be unattainable by load-serving entities exercising long-term energy contracts. This replicates LEG's assumption.

average annual savings for Option 1 and an annual average increase of $7M for Option 2 (2012 dollars). LMP cost decrease in 2015 until 2019 in Option 2 while they increase in 2020 and beyond

- For the Niagara Mohawk area, Option 1 yields a total of $132M in LMP cost savings as opposed to $73M for Option 2 (2013 NPV). This translates into $16M in average annual savings for Option 1 and $7M for Option 2 (2012 dollars).

The LMP cost savings observed by PA are lower than those outlined in LEG's analysis: LEG reported annual LMP cost savings of $142M (2012 dollars) across NYISO as opposed to only $9M in PA's analysis. PA believes that this is due to the fact that LEG did not incorporate market responses or the reaction of adjacent markets into their analysis of NYISO market impacts, as described in the previous section.

Table 2.2: Impact of the repowering on LMPs - NY Zone A and NYISO[23]

$ Nominal	NY Zone A LMPs			Price Reduction Reference Case minus Option 1/2	
Year	Reference Case	Option 1	Option 2	Option 1	Option 2
2015	$42.58	$42.28	$41.77	$0.30	$0.81
2018	$48.74	$46.63	$47.11	$2.11	$1.63
2021	$51.44	$50.08	$51.63	$1.36	-$0.20
2025	$61.54	$59.59	$61.09	$1.95	$0.45

$ Nominal	NYISO LMPs (Load Weighted Average)			Price Reduction Reference Case minus Option 1/2	
Year	Reference Case	Option 1	Option 2	Option 1	Option 2
2015	$46.82	$46.55	$46.37	$0.27	$0.45
2018	$53.69	$53.30	$53.20	$0.39	$0.49
2021	$60.51	$60.90	$61.27	-$0.38	-$0.75
2025	$72.32	$72.14	$72.58	$0.18	-$0.26

Table 2.3: LMP cost savings - PA's vs. LEG's findings

Option 1 - NYISO	PA's Study	Longwood's Study
Annual LMP Cost Savings (2012 $M)	$9	$142
Average Wholesale LMP Reduction ($/MWh)	$0.07	$1.11

2.3 Changes in ICAP Payments by Load

To determine the impact of the repowering options on ICAP payments to generators PA used its ICAP model which projects ICAP prices based on the demand curve parameters for Zone J, Zone K and NYCA

[23] A negative price reduction represents a price increase.

as reported in the latest NYISO Tariff[24]. PA has included New York's New Capacity Zone (NCZ) (which establishes a new locality comprised of NY Zones G, H, I and Jexpected to be effective in 2014) in its ICAP model. The demand curve parameters used for this zone are described in Appendix B, section B.11. Starting in 2014, the demand curve parameters were inflated using a 2.7% inflation factor.

The analysis does not consider how other market participants will respond (i.e. retirements or mothballing) to the reduction in their ICAP revenues. In addition, PA did not assume that any of the repowering options would be subject to mitigation in the capacity market.

PA projects that Option 2 will yield a larger decrease in ICAP payments than Option 1 over the study period since similar size capacity is added sooner in Option 2 than in Option 1. Under Option 2, 455MW of new capacity is added in June 2015, which significantly decreases ICAP prices beginning in 2016, while the bulk of the new capacity (422MW) under Option 1 is added in June 2017, therefore only significantly decreasing ICAP prices beginning in 2018.

Relative to the Reference Case, the total NYISO ICAP cost savings associated with Option 2 are estimated at $841M and $560M for Option 1 (2013 NPV) over the study period. Similarly, the total ICAP costsavings for the Niagara Mohawk service area are estimated at $271M in Option 2 and $201M in Option 1 (2013 NPV)[25].

Table 2.4: ICAPpayment changes relative to the Reference Case - Option 1 (Nominal $M)[26 27]

Year	Niagara Mohawk Area		Rest of State	NCZ	Zone J	Zone K	NYISO
2015	2		4	0	0	0	4
2016	(11)		(18)	(18)	0	(2)	(38)
2017	2		3	(22)	0	(4)	(23)
2018	(75)		(129)	(127)	0	(21)	(277)
2019	(90)		(155)	(86)	0	(34)	(274)
2020	(91)		(156)	(79)	0	(43)	(278)
2021	(90)		(154)	(81)	0	(50)	(285)
2022	13		23	214	0	(9)	229
2023	35		61	14	0	(14)	60
2024	0		0	171	0	(17)	154
2025	(8)		(14)	(40)	0	(21)	(74)
2013 NPV	**(201)**		**(347)**	**(89)**	**0**	**(124)**	**(560)**

[24] The Tariff is available at: http://www.nyiso.com/public/webdocs/markets_operations/documents/Tariffs/Market_Services/Tariff_Documents/NYISO_MST_05_Control_Area_Services.pdf

[25]PA assumed that approximately 58% of the Rest Of State capacity cost savings could be allocated to the Niagara Mohawk customers based on the ratio of Niagara Mohawk's peak load relative to Rest of State' peak load: the Niagara Mohawk service area coincident peak load was 7,270MW in 2012 while Rest of State (Zones A through F) peak load was approximately 12,523MW.

[26] The absolute ICAP payments are included in Appendix B, section B.11

[27] Note that the ICAP cost savings presented here have been reduced by 25% to account for savings assumed to be unattainable by load-serving entities exercising long-term energy contracts. This replicates LEG's assumption.

Table 2.5: ICAP payment changes relative to the Reference Case - Option 2 (Nominal $M)[28]

Year	Niagara Mohawk Area		Rest of State	NCZ	Zone J	Zone K	NYISO
2015	15		26	0	0	0	26
2016	(66)		(114)	(109)	0	(17)	(239)
2017	(83)		(143)	(134)	0	(26)	(302)
2018	(83)		(142)	(136)	0	(26)	(305)
2019	(82)		(141)	(79)	0	(31)	(251)
2020	(82)		(141)	(73)	0	(41)	(254)
2021	(81)		(139)	(74)	0	(47)	(260)
2022	23		39	217	0	(6)	250
2023	45		77	19	0	(12)	84
2024	9		16	178	0	(10)	184
2025	1		2	(33)	0	(15)	(46)
2013 NPV	**(271)**		**(467)**	**(230)**	**0**	**(144)**	**(841)**

Unlike LEG, PA has accounted for New York's New Capacity Zone (NCZ) in its ICAP cost calculations. Generators located in the NCZ are therefore insulated from the rent reductions (or, reduction in producer surplus) attributable to the addition of the Dunkirk capacity under Options 1 and 2. Consequently, the ICAP cost savings observed in PA's analysis are smaller than in LEG's. LEG reported annual average ICAP cost savings of $159M (2012 dollars) compared to $50M (2012 dollars) in PA's analysis.

2.4 Impact on Emissions

PA used its GE-MAPS model to derive the impact on CO2, NOx and SOx emissions under Option 1 and Option 2, across NYISO, compared to the Reference Case.

Option 1 results in a slight increase of annual average CO2 emissions (0.2%) and reductions of 2.6% of NOx and SOx emissions. The new and efficient combined cycle, with state of the art emission controls, displaces older higher emitting generating capacity, but the increase in CO2 emissions it generates in Zone A is slightly greater than the decrease in CO2 emissions of the displaced generating capacity in NYISO.

The refueled Dunkirk units in Option 2 do not have the same efficiency benefits as the new combined cycle evaluated in Option 1. In Option 2, annual average CO2 emissions increase by 1.6% while NOx and SOx emissions drop by 0.9% and 0.6% respectively.

As with the production and LMP cost savings, PA's analysis shows lower emissions benefits than LEG's study. PA believes this to be due to the more limited geographic scope of the Dayzer model compared to GE-MAPS, as discussed in section 2.1.

[28] The absolute ICAP payments are included in Appendix B, section B.11

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Figure 2-6: Reductions in NYISO emissions for Option 1 relative to the Reference Case[29]

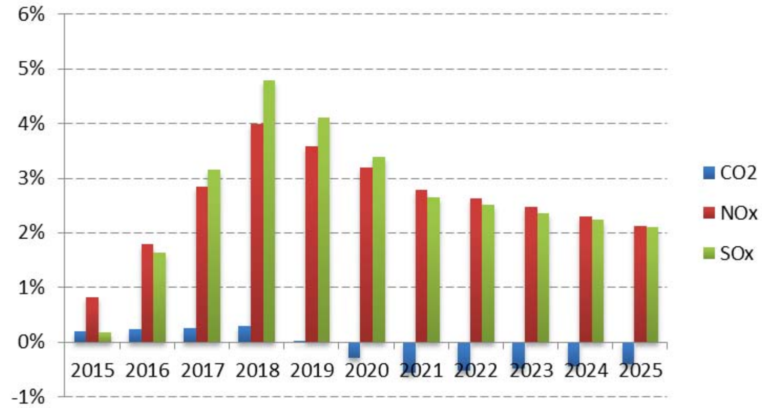

Figure 2-7: Reductions in NYISO emissions for Option 2 relative to the Reference Case[30]

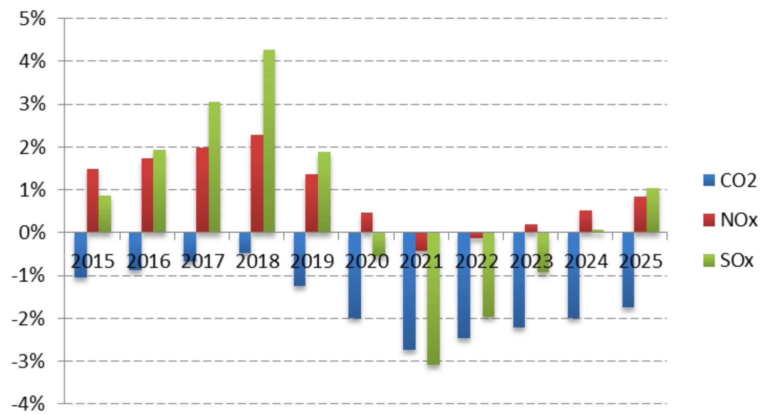

Table 2.6: Emissions reduction - PA's vs. LEG's findings

Option 1 - NYISO	PA's Study	Longwood's Study
CO2 emissions reduction[31]	-0.2%	0.8%
Nox emissions reduction	2.6%	3.2%
Sox emissions reduction	2.6%	3.5%

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[29] Negative emissions reductions represent emissions increases.

[30] Negative emissions reductions represent emissions increases.

[31] A negative emissions reduction represents an increase in emissions.

3 Economic Impact Analysis Model(EIAM) Review

Economic impact analysis studies are performed to get an understanding of the impacts of specific policies or projects on the regional economy under consideration. Two very common metrics in economic impact analysis studies are the number of jobs or job-years[32] created and the increase in the economic output, i.e. Gross Regional Product (GRP). The impacts are estimated using Economic Analysis Impact Models (EIAMs).

3.1 General Limitations of Economic Impact Analysis Models (EIAMs)

EIAM results must be regarded as estimates only, not precise forecasts. Because there are complex interactions among the participants of a regional economy, even estimates obtained by sophisticated and well-respected EIAMs are not considered to be accurate values. Most of these sophisticated models require detailed assumptions with regards to the system under evaluation; and sensitive parameters within these assumptions can significantly influence results.

Furthermore, even though EIAM studies attempt to identify and quantify the overall impact on the job creation and the economy, they are usually not comprehensive enough to account for:

- The impact of foregone investment and what economic benefits would have been achieved if those foregone investments had been realized, i.e. opportunity cost
- Displacement of economic activity and/or jobs due to investment in the project being considered

Input-output models and general/partial equilibrium models are among the most common methods used among EIAM studies.

Input-output models depend on inter-industry relationships that determine job and economic output multipliers; however these inter-industry relationships are approximations to a large extent. There are particularly sensitive factors such as date of study period, scope of the industrial sectors included, and geographical location of the project under consideration.

General/partial equilibrium models depend on estimating the demand-supply balance, which in turn determines the stabilization of the economic system. Most equilibrium models can be at partial equilibrium at most, because simulation of any real economy requires a large amount of data, and modeling each single transaction in the system is practically not feasible.

[32] Job-years is a more accurate representation of the employment impacts of a certain activity, because it captures the duration of the employment in addition to the number of jobs created. One job-year refers to full-time employment for one person during one year.

3.2 Review of the LEG Economic Impact Analysis Study

The LEG study provides a high level description of the potential benefits resulting from the construction and operation of repowering the Dunkirk facility under Option 1. While the LEG study provides a reasonable characterization of the positive aspects of NRG's proposal based on LEG's input assumptions, the study falls short of providing a full representation of the costs and benefits of the repowering options proposed by NRG.

For example;

- The LEG study does not account for costs that National Grid would incur on behalf of its customers as the counterparty to the proposed NRG contract.
- The LEG study only accounts for the benefits resulting from construction and operation of the new CCGT. Those benefits include:
  - Energy Cost Savings – reflecting the reduction in wholesale electricity prices paid by New York load.
  - Capacity Cost Savings – reflecting the reduction in wholesale capacity prices paid by New York load.
  - Macroeconomic Benefits – which quantifies the economic impacts of the construction and operation of the new CCGT, as well as the increases in expenditures resulting from benefits of lower electricity prices. Note however that the LEG study does not consider the economic impacts of reductions in generator revenues

While energy and capacity cost savings are expected to yield economic development benefits, significant uncertainty exists with regards the magnitude of these benefits. Only economic development benefits related to the operation and maintenance of the power plant can currently be projected with reasonable accuracy.

The LEG study uses the model PI+, developed by Regional Economic Models, Inc. (REMI)[33] to project economic impacts on GRP and employment. REMI is a widely used and well-respected tool to utilize for this purpose, however the study does not provide enough information about the model for the reader to follow the details and assess their validity.

3.3 Review of Publicly Available EIAMs: JEDI and WPK

PA reviewed two publicly available EIAMs, JEDI and WPK, which are designed to evaluate the economic impacts of building new naturalgas fired power plants. Based on the information available in the report, *Dunkirk RepoweringOptions*submitted to National Grid by NRG, and the report *NRG Dunkirk Repowering Project - Economic Impact Analysis,* submitted to NRG by LEG, PA obtained a range of economic impact estimates using the JEDI and WPK models.

Before presenting those estimates, Sections 3.3.1 and 3.3.2 provide a brief summary about the JEDI and WPK models.

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[33]REMI was founded in 1980 to assist policy makers in making economic policy decisions, and has been widely used since then. REMI's product PI+ is designed to simulate economic and demographic effects of specific policy initiatives, and is calibrated to sub-national areas.

3.3.1 Jobs and Economic Development Model (JEDI)

JEDI models are developed by MRG &Associates under contract with the National Renewable Energy Laboratory(NREL) to estimate the "economic impacts of constructing and operating power plants, fuel production facilities, and other projects at the local (usually state) level". There are a set of JEDI models that simulate the characteristics of specific generation technologies such as coal, wind, biofuels, solar, and natural gas. Model defaults are based on industry experts and project developers. PA used "JEDI Natural Gas Model" as part of this literature review.

JEDI Natural Gas is an input-output based model that utilizes 14 aggregated industries. Default values[34] representing average costs and spending patterns within the specified economy are developed from a number of resources. Input data includes project specific parameters such as construction costs, annual O&M costs, capacity factor, heat rate, etc. Model output consists of direct, indirect and induced employment, earnings and economic output.

3.3.2 Wei, Patadia and Kammen (WPK)[35] Model

The WPK model is an analytical job creation model published in the academic journal *Energy Policy,* and developed based on previous studies on the US power sector between 2009 and 2030. The authors first reviewed 15 studies on the job creation potential of different power generation technologies including natural gas plants. Based on the data collected during the review, the authors developed "job multipliers" normalized by the amount of energy produced over the lifetime of the generating technology under consideration.

Note that the WPK model does not differentiate between state and out-of-state economic impacts. The reported natural gas plant job multiplier, 0.11 job-years/GWh, includes fuel extraction and processing induced employment which may or may not accrue to New York State.

Also note that WPK model only estimates economic impact on job creation, and does not provide an estimate for the impact on economic output.

3.3.3 JEDI and WPK Model Inputs and Outputs

Table 3.1summarizes the input data used by PA in reviewing the JEDI and WPK models. Note that this data is collected from the LEG study in addition to NRG's response to National Grid's RFP.

Table 3.1: Input data used by PA for the JEDI and WPK model review

Category	Data
Project Location	New York
Year Construction Starts	2013
Project Size - Nameplate Capacity (MW)	422
Capacity Factor	65%

[34] Default values are derived from IMPLAN ProfessionalTM state data files.

[35] Wei, Max, Shana Patadia, and Daniel M. Kammen. "Putting renewables and energy efficiency to work: How many jobs can the clean energy industry generate in the US?" Energy Policy 38.2 (2010): 919-931.

Heat Rate (Btu per kWh)	[redacted]
Construction Period (Months)	[redacted]
Plant Construction Cost ($/KW)	[redacted]
Fixed Operations and Maintenance Cost ($/kW)	[redacted]
Variable Operations and Maintenance Cost ($/MWh)	[redacted]
WPK job multiplier for natural gas (job-years/GWh)	0.11
Local property tax	[redacted]
Duration of Plant Operation	10 years[4]
Money Value (Dollar Year)	2012

[redacted]

[3]Value chosen to reflect the PILOT payment schedule between NRG and Chautauqua Industrial Development Agency.

Source: Attachment A to NRG Energy, Inc. Response to NMPC-1

[4]Study period chosen by LEG.

The inputs indicated in Table 3.1 resulted in the following estimates by the JEDI and WPK models as shown in Table 3.2.

Table 3.2: Estimates by the JEDI and WPK model for repowering Dunkirk under Option 1

	Job-Years	Output*
Construction Period	430 - 1,070	approx. $205M
Operation Period (10 years)	420 - 860	approx. $210M
TOTAL	850 - 1,930	approx. $415M

* Equivalent to GRP.

3.3.4 Limitations of JEDI and WPK

In addition to the general limitations of EIAMs mentioned in Section 3.1, neither JEDI nor WPK accounts for potential changes in electricity prices due to new generation added to the system. For example, new economic generation might lead to lower electricity prices in the region due to increased supply. In turn, lower electricity prices might lead to higher purchasing power for consumers, i.e. “ratepayer benefit”.Ratepayer benefit might induce additional jobs and increase output in a local economy. PA recognizes that LEG accounted for the ratepayer benefit impact in their analysis; however the details of how that impact was estimated are not described within the LEG study.

3.4 Comparison of LEG's Analysis with the JEDI and WPK Model Results

As noted earlier, LEG incorporated a ratepayer benefit input into the economic impact estimation. Because publicly available models reviewed by PA did not include ratepayer benefit impacts, PA excluded LEG's ratepayer benefit related estimations from the comparison shown in Table 3.3below.

Table 3.3: Comparison of LEG's analysis with the JEDI and WPK model results

	JEDI and WPK	LEG
	Total Job-Years Created, 10 Years of Operation	
Construction Period	430 - 1,070	924*
Operation Period	860 - 2,585	3,160
TOTAL	1,290 - 3,655	4,084
	Increase in GRP ($2012)	
TOTAL	approx. $415M	$413M

* Based on a three-year construction period.

Comparison of the LEG analysis with the JEDI and WPK model results suggests that LEG's total job-years estimate falls outside of the estimated range by JEDI and WPK; but the total GRP estimates are in close agreement.

However, it should be noted that the *total* economic impact estimated by LEG was mostly induced by the ratepayer benefit which created 7-10 times more jobs and economic output compared to the O&M spending impacts. Because the publicly available models reviewed by PA did not have the ratepayer benefit component, the comparison of those estimates falls outside the scope of this literature review.

In addition and as noted previously in this report, significant uncertainty exists with regards to the magnitude of the economic impact which could be induced by ratepayer benefits.

Appendix A: 2010 Backcast

A.1 Approach

PA has completed a 2010 GE-MAPS backcast which served as a base model for the Dunkirk Repowering Study. The backcast represents a comparison of the GE-MAPS model outputs to actual energy market characteristics for the year 2010.

The following GE-MAPS model inputs were updated based on publicly available data to reflect 2010 actuals:

- Fuel and Emission Prices
- NYISO's major transmission interface definitions and ratings
- Peak load, energy consumption and load shapes for all NYISO, PJM, ISO-NE and IESO zones
- Installed capacity for the NYISO
- Hydro Quebec net energy exports to the U.S.

A.2 2010 Backcast Generation and Prices vs. Actuals

PA successfully captured the pricing pattern from zone to zone within NYPP, considering that the impact of marginal losses on prices is not captured by GE-MAPS (the algorithms GE has built into GE-MAPS to deal with marginal losses are not performing as intended, therefore PA opted not to use them for this study).

PA has constructed an approximation in the MAPS model, using a "tax" on inter zonal transmission as a proxy for loss costs. This approximation had a price pattern similar to the 2010 price pattern including marginal loss costs. But given that GE is coming out with a permanent fix and the fact that PA understands and can explain why the inter zonal price differences are smaller, it was decided to run the model as configured by GE rather than utilizing PA's approximation workaround, which would have required additional validation and calibration.

In addition to the similar pricing patterns, PA has observed a good correlation regarding generator outputs: New York (NY) Zone A total annual energy generation is within 3% of the 2010 actual generation reported by the New York Independent System Operator (NYISO), as shown in Table A.1 and Table A.2. Furthermore, the total annual generation of the Dunkirk units falls within 7% of the 2010 actuals.

Table A.1: Generation by NY Zones: GE-MAPS backcast vs. 2010 actuals

Zone	Actual Energy (GWh)	2010 Backcast Energy (GWh)
A	23,019	22,222
B	5,204	4,907
C	28,775	30,989
D	8,245	9,587
E	3,325	3,913
F	16,541	19,140

G	2,668	4,237
H	16,727	16,920
I	1	0
J	22,723	22,195
K	12,128	11,266
Grand Total	**139,357**	**145,375**

Table A.2: Energy prices by NY Zones: GE-MAPS backcast vs. 2010 actuals

Zone	2010 Day Ahead Market Spot Price ($/MWh) - NYISO	2010 Day Ahead Market Spot Price excluding impact of marginal losses ($/MWh)	2010 Backcast Price ($/MWh) - GE-MAPS
A	$39.22	$42.03	$44.11
B	$41.29	$42.49	$45.29
C	$42.54	$42.63	$44.57
D	$40.61	$41.93	$44.63
E	$44.13	$42.70	$44.76
F	$49.24	$47.04	$49.52
G	$50.98	$47.09	$48.76
H	$51.37	$47.48	$49.05
I	$51.53	$47.54	$48.45
J	$54.97	$50.64	$52.35
K	$59.41	$54.18	$55.03

Figure A.1: Zonal pricing pattern: GE-MAPS vs. 2010 actuals

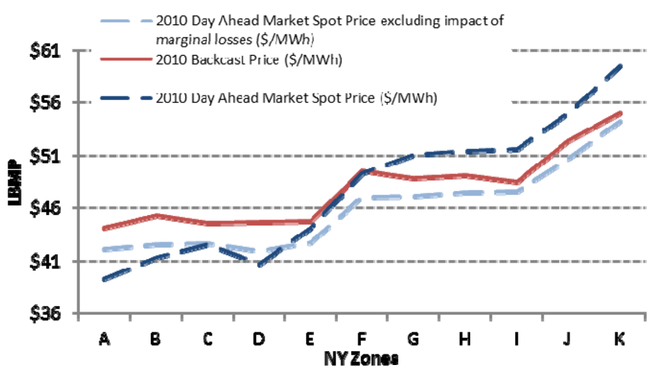

Table A.3: Generation of major Zone A power plants: GE-MAPS vs. 2010 actuals

NYISO Name	2010 Actual Generation (GWh)	GE-MAPS Generation (GWh)
Moses Niagara (Fleet)	12042	12042
Somerset	4596	3424
Huntley 68	1074	823

Dunkirk 3	**1053**	**921**
Huntley 67	974	890
Dunkirk 4	**890**	**925**
Lewiston PS (Fleet)	502	515
Dunkirk 2	**366**	**324**
Dunkirk 1	**359**	**322**
Total Dunkirk Units	**2667**	**2492**
Indeck-Olean	279	363
American Ref-Fuel 1	240	252
Bliss Wind Power	188	296
Niagara Bio-Gen	57	165
Lockport Cogen GT1	51	18
Steel Winds	48	41

Appendix B: Assumptions

B.1 Natural Gas Price Forecasts

Natural gas price forecasts used by PA are based on Henry Hub price projections from the 2013 EIA Annual Energy Outlook Early Release and SNL's 2012 actual basis differentials. Delivered prices account for local delivery charges and applicable taxes.

The regional hubs utilized to determine the delivered price for each region in the study area are as follows:

- NY Zones A – D are based on Niagara
- NY Zones E – F are based on Iroquois Zone 1
- NY Zones G – I are based on TETCO M-3
- NY Zones J – K are based on Transco Zone 6 NY
- New England (except NH & ME) are based on Algonquin City-Gates
- Eastern PJM (i.e. NJ, MD, DE & eastern PA) are based on Transco Zone 6 non-NY.

Table B.1lists the projected natural gas prices by region between 2015 and 2025.

Table B.1: Projected natural gas prices, 2015-2025

NATURAL GAS PRICE FORECAST (Nominal $/MMBtu)								
	Henry Hub	Zones A-D	Zones E-F	Zones G-I	Zone J[1]	Zone K	Eastern PJM[2]	New England[3]
2015	3.45	3.84	4.41	3.73	4.17	3.99	3.72	4.94
2016	4.05	4.51	5.17	4.39	4.89	4.68	4.37	5.80
2017	4.31	4.80	5.51	4.67	5.21	4.99	4.65	6.18
2018	4.74	5.28	6.06	5.13	5.73	5.48	5.11	6.79
2019	4.98	5.54	6.36	5.39	6.02	5.76	5.37	7.13
2020	5.22	5.82	6.67	5.66	6.31	6.04	5.63	7.48
2021	5.53	6.15	7.06	5.98	6.68	6.39	5.96	7.92
2022	5.97	6.64	7.62	6.46	7.21	6.90	6.43	8.55
2023	6.40	7.12	8.17	6.93	7.73	7.40	6.90	9.17
2024	6.73	7.49	8.60	7.29	8.13	7.78	7.25	9.64
2025	7.03	7.83	8.98	7.61	8.50	8.13	7.58	10.07

Prices shown do not include LDCs.

[1] Includes 4.5% New York City local tax.

[2] This price covers NJ, DE, MD and eastern PA.

[3] This price covers all New England states except NH & ME.

B.2 Delivered Fuel Oil Prices - FO2 & FO6

Delivered fuel oil prices are derived from the 2013 EIA's Annual Energy Outlook Early Release. Proportionate differentials observed in previous analyses were used to define prices for the various fuel grades. Table B.2 lists the fuel oil prices by grade between 2015 and 2025 for Long Island and New York City.

Table B.2: Oil price forecast by grade between 2015 and 2025

OIL PRICE FORECAST (Nominal $/MMBtu)									
	Distillate Oil		FO6						
	LI	NYC	LI .3	LI .5	LI .7	LI 1.0	NYC .3	NYC .5	NYC .7
2015	22.94	23.93	14.03	13.29	12.50	12.30	14.66	13.88	13.06
2016	23.98	25.02	14.76	13.98	13.15	12.95	15.42	14.61	13.75
2017	25.14	26.23	15.37	14.56	13.70	13.48	16.06	15.21	14.32
2018	26.23	27.37	16.37	15.51	14.59	14.36	17.11	16.20	15.25
2019	27.45	28.64	17.10	16.20	15.24	15.00	17.87	16.93	15.93
2020	28.66	29.91	18.09	17.13	16.12	15.87	18.90	17.91	16.85
2021	29.97	31.27	19.05	18.04	16.97	16.71	19.90	18.85	17.74
2022	31.32	32.68	20.06	19.00	17.88	17.60	20.96	19.85	18.68
2023	32.75	34.18	21.13	20.01	18.83	18.54	22.08	20.91	19.68
2024	34.25	35.75	22.29	21.11	19.86	19.55	23.29	22.06	20.76
2025	35.87	37.43	23.37	22.14	20.83	20.50	24.42	23.13	21.77

B.3 Peak Hour Demand and Annual Energy Forecast

Peak hour demand and annual energy forecasts are based on the following resources:

- ISO-NE's 2012 CELT Report through 2021:
  - 2017-2021 CAGR for peak load and annual energy was used to extrapolate data from 2022 to 2025.
- NYISO's 2012 Load and Capacity Data (Gold Book) publication which includes the impact of energy efficiency programs through 2022
  - The 2012 Gold Book peak load and energy for all NY Zones through 2022 was used and grown by the 2018-2022 CAGR to complete the forecast from 2023 through 2025.
- PJM's December 2012 Load Forecast Report through 2025
- Ontario's (IESO) Reserve Margin Requirements 2013-2017
  - 2013-2017 CAGR for peak load and annual energy was used to extrapolate data from 2018 to 2025.

Table B.3 and Table B.4 tabulate the summer peak hour and annual energy demand by zone between 2015 and 2025, respectively.

Table B.3: Summer peak hour demand between 2015 and 2025

SUMMER PEAK HOUR DEMAND (MW)						
	2012 Goldbook			2012 ISO - NE CELT Report	PJM Load Forecast Report Dec 2012	Ontario Reserve Margin Requirements (2013-2017)
	NY Zone J (Non-coincident)	NY Zone K (Non-coincident)	NYISO (Coincident)	ISO - NE (Coincident)	PJM RTO (Coincident)	Ontario (Coincident)
2015	11,985	5,710	34,151	28,840	160,321	22,858
2016	12,095	5,723	34,345	29,400	163,176	22,640
2017	12,200	5,756	34,550	29,895	165,226	22,471
2018	12,400	5,797	34,868	30,275	166,810	22,268
2019	12,570	5,843	35,204	30,605	168,509	22,067
2020	12,725	5,900	35,526	30,930	170,290	21,868
2021	12,920	5,965	35,913	31,255	172,081	21,671
2022	13,050	6,038	36,230	31,605	173,720	21,475
2023	13,218	6,100	36,579	31,958	175,328	21,281
2024	13,388	6,162	36,931	32,315	176,919	21,089
2025	13,560	6,225	37,286	32,677	178,573	20,899
CAGR*	1.24%	0.87%	0.88%	1.26%	1.08%	-0.89%

* Between 2015 and 2025.

Table B.4: Annual energy demand between 2015 and 2025

ANNUAL ENERGY DEMAND (MWH)						
	2012 Goldbook			2012 ISO - NE CELT Report	PJM Load Forecast Report Dec 2012	Ontario Reserve Margin Requirements (2013-2017)
	NY Zone J	NY Zone K	NYISO	ISO - NE	PJM	Ontario
2015	55,234	23,622	166,030	142,215	852,514	128,000
2016	55,756	23,774	166,915	143,815	871,879	124,800
2017	55,725	23,833	166,997	145,245	881,525	123,000
2018	56,306	24,039	168,021	146,590	890,913	120,215
2019	57,096	24,260	169,409	147,880	899,125	117,493
2020	58,086	24,607	171,176	149,130	911,994	114,833
2021	58,772	24,855	172,514	150,375	920,291	112,233
2022	59,118	25,217	173,569	151,686	930,179	109,692
2023	59,843	25,520	174,984	153,008	939,120	107,208

2024	60,576	25,827	176,411	154,341	950,081	104,781
2025	61,319	26,138	177,850	155,686	956,674	102,408
CAGR*	1.05%	1.02%	0.69%	0.91%	1.16%	-2.21%

* Between 2015 and 2025.

B.4 Long-Term Capacity Additions

PA added thermal capacity over the study period only when it was economic to do so, i.e. when ICAP prices were expected to exceed the net Cost of New Entry (CONE).

PA has added renewable capacity throughout New York State to meet the state RPS requirements. New York RPS requirements call for 29% renewable energy by 2015, but this analysis assumed a three-year delay in meeting the requirement (i.e. it will be met by 2018). PA followed the methodology employed in the 2009 CARIS analysis to meet this target, adding only wind to meet the incremental renewable energy requirements. Necessary capacity was derived based on the existing NYISO interconnection queue.

B.5 Build Plans

Based on the capacity additions methodology outlined in Section B.4, PA has added generic capacity in its GE-MAPS model as shown in Table B.5, in addition to the capacity added under the Dunkirk repowering cases.

Table B.5: Generic capacity added by PA in its GE-MAPS model

Case	New Capacity in Zone G	New Capacity in Zone J	New Capacity in Zone K
Reference Case	520MW Combined Cycle in 2022 345MW Combustion Turbine in 2024	520MW Combined Cycle in 2025	520MW Combined Cycle in 2023
Option 1	520MW Combined Cycle in 2023	520MW Combined Cycle in 2025	520MW Combined Cycle in 2024
Option 2	520MW Combined Cycle in 2023	520MW Combined Cycle in 2025	520MW Combined Cycle in 2024
Option 3	520MW Combined Cycle in 2022	520MW Combined Cycle in 2025	520MW Combined Cycle in 2024

B.6 Capacity Retirements for the 2013-2025 Period

Table B.6shows the capacity retirement plan that PA used for the 2013-2025 period.

Note that Dunkirk 3 and 4 are retired in 2012 and that Dunkirk 2 is retired at the end of 2014 in the Reference Case. Also note that Danskammer units 1 through 6 have been out of service since 10/29/12 as this report is written, and therefore PA assumed that they were effectively retired within 2012.

Cayuga 1 and 2 were assumed to be in service throughout the study period.

PA has not assumed any additional retirements as a consequence of price reductions driven by the Dunkirk repowering. A reasonable approach is to assume that additional retirements would reduce the

ICAP payment benefits of a Dunkirk repowering by approximately the ratio of the retired capacity to the repowered Dunkirk capacity.

Table B.6: Capacity retirement plan for the 2013-2025 period

Unit Name	Retirement Date	Unit Name	Retirement Date
Dunkirk 1	12/31/2013	Astoria GT 7	12/31/2014
Montauk 2 IC	12/31/2013	Astoria GT 8	12/31/2014
Montauk 3 IC	12/31/2013	Astoria GT 12	12/31/2014
Montauk 4 IC	12/31/2013	Astoria GT 13	12/31/2014
Astoria GT5	12/31/2014		

B.7 New York State Transmission Improvement Suggested by National Grid

PA has revised its load flows for all the cases considered for this study to include the transmission projects identified by National Grid as needed irrespective of the operation or retirement of the Dunkirk units.

In addition, the “Retirement Transmission Upgrades” Case includes the following upgrades.

- Addition of two 33.3 MVAr capacitor banks on the two Dunkirk 115kV bus sections
- Addition of a second 75 MVAr capacitor bank at the Huntley 115kV switchyard
- Reconductoring of the two 115kV lines between Five Mile Rd and Homer Hill
- Reconductoring of one mile of the Niagara – Gardenville #180 line
- Reconductoring of 14 miles of the Packard – Erie #181 line.

The Hudson Transmission Project (HTP) has also been included in PA's load flows.

B.8 New England Transmission Improvements

The following recent and future transmission projects were included in the analysis:

1. NSTAR Reliability Project (Stoughton-Hyde Park/K Street) – 2008-2009
2. Southwest Connecticut Reliability Project – 2007-2009
3. Fitzwilliam Substation (New Hampshire) – 2009
4. Wakefield Junction Substation (North Shore) – 2009
5. Norwalk – Glenbrook Cable (Connecticut) – 2010
6. Maine Power Reliability Project – 2013
7. Central/Western Massachusetts Upgrades – 2012
8. Greater Rhode Island Transmission Reinforcements – 2012
9. Berry Street Substation (SEMA/RI) – 2012
10. NEEWS Interstate – 2013-2014
11. NEEWS Rhode Island Reliability – 2013

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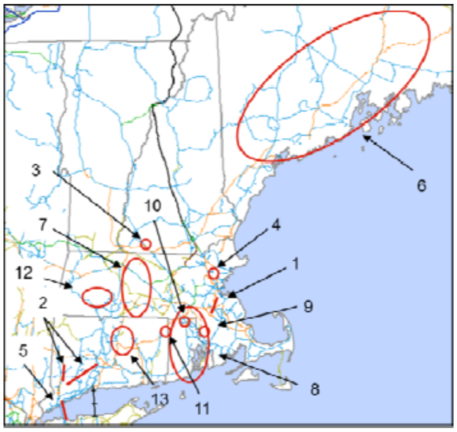
12. NEEWS Greater Springfield Reliability – 2014
13. NEEWS Central Connecticut – 2014

Figure B.1 represents the geographic location of these transmission projects.

Figure B.1: Recent and future transmission projects included in the analysis



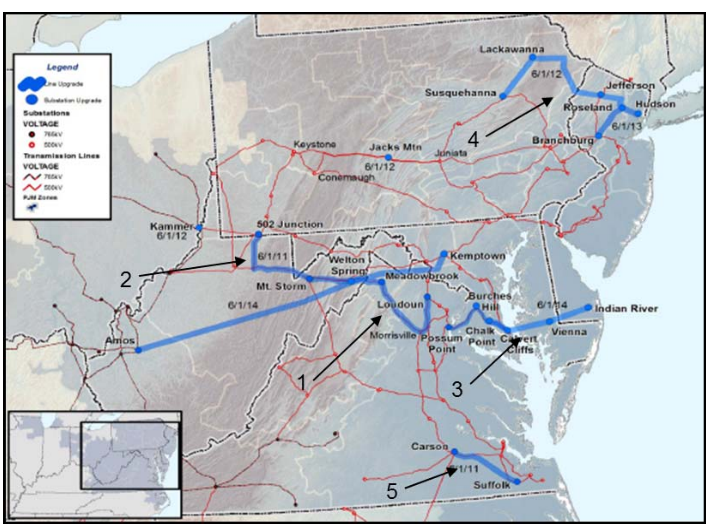
B.9 PJM Transmission Improvements

Major PJM transmission projects that were included in the analysis are as follows:

1. TrAIL – 500kV line from the 502 Junction substation in SW Pennsylvania to the Loudon substation in Virginia, 2012 in-service date
2. 500kV line from the Susquehanna substation in Pennsylvania to the Roseland substation in New Jersey built in conjunction with a 500 kV line from Branchburg to Roseland to Hudson. Will be built in stages – two stages completed in 2014 with central connecting stage in 2015.
3. 500kV line from Carson to Suffolk in Virginia, 2011 in-service date.

Figure B.2 shows these PJM transmission projects on the regional map.

Figure B.2: PJM transmission projects



B.10 Hydro Quebec Net Exports

PA used the projections listed in Table B.7to represent the net future energy exports from Hydro Quebec.

Table B.7: Projected net energy exports from Hydro Quebec

HYDRO QUEBEC PROJECTED NET ENERGY EXPORTS* (GWH)						
	Ontario	New York	New Brunswick	New England Phase II	New England Highgate	Total HQ
2015	3,445	6,787	1,752	10,436	1,577	23,997
2016	3,902	7,044	1,752	10,724	1,577	24,999
2017	4,763	7,346	1,752	11,062	1,577	26,500
2018	5,624	7,648	1,752	11,399	1,577	28,000
2019	5,954	7,894	1,752	11,489	1,577	28,666
2020	6,283	8,141	1,752	11,580	1,577	29,333
2021	6,613	8,387	1,752	11,670	1,577	29,999
2022	6,613	8,387	1,752	11,670	1,577	29,999
2023	6,613	8,387	1,752	11,670	1,577	29,999
2024	6,613	8,387	1,752	11,670	1,577	29,999
2025	6,613	8,387	1,752	11,670	1,577	29,999

* Note that the projections for the years 2015, 2016, 2018, 2021 and 2024 were derived from Charles River Associate's (CRA) 2010 study on "LMP and Congestion impacts of Northern Pass Transmission Project". Projections for other years are linearly interpolated based on CRA's projections.

B.11 ICAP Model

PA updated its ICAP Model using the 2009-2013 Demand Curve parameters reported in the latest NYISO Tariffs. The Demand Curve parameters for the outer years (2014-2025) were based on the 2013 parameters and were inflated using a 2.7% factor. Estimated ICAP prices for Option 1 and Option 2, and their differences compared to the Reference Case are tabulated in Table B.8 and Table B.9 respectively.

In addition, the New York NCZ has been added to PA's ICAP model. The NCZ establishes a new locality comprised of NY Zones G, H, I and J, and is expected to be effective in 2014.

PA has used the following assumptions to model the NCZ:

- Peak demand: the peak demand of the NCZ is the sum of the Zone G, Zone H, Zone I and Zone J summer peak demands
- Demand curve parameters: for the reference price (price at 100% on the demand curve), PA used $14.50 (for both summer and winter) which represents the average of the NYCA and Zone J prices, as recommended in Attachment XII, item 21 of the NYISO filing addressing the revisions to the tariff due

to the addition of the NCZ[36] – Affidavit of Tariq N.Niazi. In addition, PA used a 112% zero crossing point, which replicates the assumption described in Attachment XII, item 21 of the NYISO filing

- Locational Requirements (LCRs): PA used a 88% LCR to replicate the findings outlined in Attachment XIV of the NYISO filing
- Derating factors: PA assumed that the NCZ and NYCA would have the same derating factor
- PA assumed that the monthly ICAP price (summer and winter) for the NCZ will equal the maximum of the NYCA and NCZ ICAP price.

Table B.8: Estimated ICAP prices and payments for the Reference Case and Option 1

ICAP PRICES ($/kW-Year)												
	Reference Case				Option 1				Difference (Option 1 - Reference Case)			
Year	Rest of State	Zone J	Zone K	NCZ	Rest of State	Zone J	Zone K	NCZ	Rest of State	Zone J	Zone K	NCZ
2015	$64	$110	$68	$64	$64	$110	$68	$64	$0	$0	$0	$0
2016	$71	$132	$75	$71	$70	$132	$74	$70	-$1	$0	$0	-$1
2017	$79	$150	$81	$79	$77	$150	$81	$77	-$2	$0	-$1	-$2
2018	$90	$176	$90	$90	$81	$176	$88	$81	-$9	$0	-$3	-$9
2019	$102	$204	$102	$102	$90	$204	$95	$95	-$13	$0	-$8	-$7
2020	$110	$224	$110	$115	$97	$224	$100	$109	-$13	$0	-$10	-$7
2021	$122	$250	$122	$134	$109	$250	$111	$128	-$13	$0	-$11	-$7
2022	$127	$277	$130	$127	$123	$277	$125	$147	-$4	$0	-$4	$21
2023	$127	$305	$127	$134	$127	$305	$136	$136	$1	$0	$9	$2
2024	$130	$335	$130	$130	$128	$335	$128	$149	-$3	$0	-$3	$19
2025	$132	$313	$132	$132	$128	$313	$128	$132	-$4	$0	-$4	$0

ICAP Payments $M Nominal												
	Reference Case				Option 1				Difference (Option 1 - Reference Case)			
Year	Rest of State	Zone J	Zone K	NCZ	Rest of State	Zone J	Zone K	NCZ	Rest of State	Zone J	Zone K	NCZ
2015	$1,204	$1,127	$374	$948	$1,210	$1,127	$374	$948	$5	$0	$0	$0
2016	$1,333	$1,324	$405	$1,049	$1,311	$1,324	$402	$1,027	-$23	$0	-$3	-$22
2017	$1,481	$1,498	$445	$1,165	$1,485	$1,498	$439	$1,138	$4	$0	-$5	-$28
2018	$1,694	$1,778	$497	$1,333	$1,533	$1,778	$471	$1,174	-$161	$0	-$26	-$159
2019	$1,934	$2,055	$563	$1,522	$1,740	$2,055	$520	$1,414	-$194	$0	-$42	-$107
2020	$2,054	$2,232	$598	$1,684	$1,859	$2,232	$543	$1,585	-$195	$0	-$54	-$99
2021	$2,308	$2,521	$672	$1,989	$2,116	$2,521	$609	$1,889	-$193	$0	-$62	-$101
2022	$2,349	$2,776	$697	$1,913	$2,379	$2,776	$686	$2,182	$29	$0	-$11	$268
2023	$2,346	$3,063	$748	$2,019	$2,422	$3,063	$730	$2,036	$76	$0	-$18	$17
2024	$2,426	$3,370	$774	$2,021	$2,426	$3,370	$753	$2,235	$0	$0	-$21	$214
2025	$2,451	$3,176	$782	$2,111	$2,434	$3,176	$756	$2,061	-$17	$0	-$26	-$50
2013 NPV	**$12,793**	**$14,418**	**$3,871**	**$10,455**	**$12,363**	**$14,418**	**$3,713**	**$10,345**	**-$433**	**$0**	**-$155**	**-$111**

[36] Proposed Tariff Revisions to establish and recognize a New Capacity Zone and Request for Action on Pending Compliance Filing, Docket No. ER13-____-000, filed on April 30, 2013.

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Table B.9: Estimated ICAP prices and payments for the Reference Case and Option 2

ICAP PRICES ($/kW-Year)												
	Reference Case				Option 2				Difference (Option 2 - Reference Case)			
Year	Rest of State	Zone J	Zone K	NCZ	Rest of State	Zone J	Zone K	NCZ	Rest of State	Zone J	Zone K	NCZ
2015	$64	$110	$68	$64	$64	$110	$68	$64	$0	$0	$0	$0
2016	$71	$132	$75	$71	$64	$132	$73	$64	-$7	$0	-$2	-$7
2017	$79	$150	$81	$79	$67	$150	$76	$67	-$11	$0	-$6	-$11
2018	$90	$176	$90	$90	$78	$176	$85	$78	-$12	$0	-$6	-$12
2019	$102	$204	$102	$102	$91	$204	$95	$96	-$12	$0	-$7	-$7
2020	$110	$224	$110	$115	$98	$224	$101	$109	-$12	$0	-$9	-$6
2021	$122	$250	$122	$134	$110	$250	$111	$128	-$12	$0	-$11	-$6
2022	$127	$277	$130	$127	$124	$277	$126	$148	-$3	$0	-$4	$21
2023	$127	$305	$127	$134	$129	$305	$137	$136	$2	$0	$10	$2
2024	$130	$335	$130	$130	$129	$335	$129	$149	-$1	$0	-$1	$19
2025	$132	$313	$132	$132	$129	$313	$129	$133	-$3	$0	-$3	$0

ICAP Payments $M Nominal												
	Reference Case				Option 2				Difference (Option 2 - Reference Case)			
Year	Rest of State	Zone J	Zone K	NCZ	Rest of State	Zone J	Zone K	NCZ	Rest of State	Zone J	Zone K	NCZ
2015	$1,204	$1,127	$374	$948	$1,236	$1,127	$374	$948	$32	$0	$0	$0
2016	$1,333	$1,324	$405	$1,049	$1,191	$1,324	$384	$914	-$142	$0	-$21	-$136
2017	$1,481	$1,498	$445	$1,165	$1,301	$1,498	$413	$998	-$179	$0	-$32	-$167
2018	$1,694	$1,778	$497	$1,333	$1,516	$1,778	$464	$1,163	-$178	$0	-$33	-$170
2019	$1,934	$2,055	$563	$1,522	$1,759	$2,055	$524	$1,423	-$176	$0	-$39	-$99
2020	$2,054	$2,232	$598	$1,684	$1,878	$2,232	$546	$1,594	-$176	$0	-$51	-$91
2021	$2,308	$2,521	$672	$1,989	$2,135	$2,521	$612	$1,897	-$174	$0	-$59	-$92
2022	$2,349	$2,776	$697	$1,913	$2,398	$2,776	$689	$2,184	$49	$0	-$8	$271
2023	$2,346	$3,063	$748	$2,019	$2,442	$3,063	$734	$2,043	$96	$0	-$15	$24
2024	$2,426	$3,370	$774	$2,021	$2,446	$3,370	$760	$2,244	$20	$0	-$13	$223
2025	$2,451	$3,176	$782	$2,111	$2,455	$3,176	$763	$2,070	$3	$0	-$19	-$41
2013 NPV	**$12,793**	**$14,418**	**$3,871**	**$10,455**	**$12,210**	**$14,418**	**$3,690**	**$10,168**	**-$584**	**$0**	**-$180**	**-$287**

Note that the ICAP cost savings presented here do not match the savings presented in section 2.3 because they have not been reduced by 25% to account for savings assumed to be unattainable by load-serving entities exercising long-term energy contracts.

Appendix C: Review of the Production Cost Modeling Assumptions used by LEG

PA believes that the data sources used by Longwood for its “Economic Impact Analysis” are reasonable since most of those sources were also used for this study: PA and Longwood used the same data sources for fuel prices forecasts and demand growth, and a similar methodology for generation additions and retirements was implemented.

However, we cannot opine on the quality of LEG's model inputs for its production cost analysis without analyzing them in details.

The assumptions most likely to drive large changes in the production cost model outputs if they were to be revised are:

- Natural gas prices forecasts
- Demand forecasts
- Capacity retirement and addition.

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Exhibit 7

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STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

Case No. 12-E-0577
Proceeding on Motion of the Commission to Examine Repowering Alternatives to Utility Transmission Reinforcements

AFFIDAVIT OF MICHAEL D. CADWALADER

SUMMARY

1. The assessment of whether investment in new generation is in the interest of consumers should be based upon a comparison of the net benefits that would result from the addition of those generators—including both the reduction in energy production costs that would result from adding generators and the value of the capacity that such generators would provide—to the net cost of developing and constructing those generators. Economically efficient additions to the generation fleet, which actually reduce the overall cost of meeting consumers' energy needs and providing the capacity required to meet reliability criteria, will benefit consumers. But the evaluation of whether new generation is economically efficient should not rely upon the impact that new generators would purportedly have on market-clearing prices for energy and capacity. It is unlikely that inefficient entry will have a significant and lasting impact on prices, as other market participants are likely to respond by mothballing or retiring generating capacity, which could largely or completely offset the impact of the new generation on prices, leaving consumers with the obligation to purchase energy and capacity provided by inefficient generators at above-market costs. Economically inefficient entry that is supported through out-of-market contracts could also undermine the ability for the market to support economically efficient entry, as prospective developers may fear that the market prices they would receive would be suppressed through such contracts. It may also increase the likelihood that entrant mitigation,

which might discourage economically efficient entry, would be applied statewide. My evaluation of two repowering proposals offered by NRG Energy in this proceeding indicates that they would be economically inefficient, as the costs of payments that would be made to NRG Energy considerably exceed the net benefits that would result from development of the generators envisioned under either proposal. Consequently, I believe that the Commission should not direct implementation of either of those repowering proposals, as I would not expect them to benefit consumers.

PERSONAL AND PROFESSIONAL BACKGROUND

2. My name is Michael D. Cadwalader. I am a director with Atlantic Economics LLC, an economic consulting firm. My business address is 540 Main Street, Suite 8, Winchester, Massachusetts 01890.

3. I received an A.B. degree, *summa cum laude*, in mathematics and economics from Washington University in St. Louis in 1985, an M.A. degree in economics from the University of Rochester in 1988, and an M.B.A., with distinction, in finance and strategic management from The Wharton School of the University of Pennsylvania in 1994.

4. Since then, I have been an economic consultant, initially with Putnam, Hayes & Bartlett, and then with LECG, before founding Atlantic Economics. My consulting practice has primarily consisted of advising clients on the development of competitive electricity markets, and assisting clients in understanding the implications of these markets for their businesses.

5. I have consulted with clients regarding the structure of electricity markets operated by New York Independent System Operator, Inc. (“NYISO”), the Midwest Independent Transmission System Operator, Inc., ISO New England, PJM Interconnection LLC, the California Independent System Operator Corporation, the Electric Reliability Council of Texas,

and the Ontario Independent Electricity System Operator, as well as several markets outside North America.

6. My involvement in the development of the electricity markets operated by the NYISO began in 1994, several years before those markets began operation. Specifically, I assisted the Member Systems of the New York Power Pool (now known as the New York Transmission Owners ("NYTOs")) in the development of these markets, which they eventually transferred to the NYISO in accordance with FERC Order No. 888.

7. Since the NYISO began to administer the electricity markets in New York in late 1999, I have been engaged by the NYTOs to advise them regarding the structure of the NYISO's markets. As part of that work, I participated in many initiatives that are intended to yield more efficient commitment and scheduling procedures, in both the day-ahead and within-day timeframes.

8. I have also been involved in the development of all of the major changes to the New York ICAP market that have occurred since the initial implementation of that market, including: the initial development of the NYISO's installed capacity demand curves in 2002 and 2003; the determination of the parameters for those demand curves for 2005-08, 2008-11 and 2011-14; the development of enhanced procedures for reporting the potential impact of the exercise of market power, and measures for mitigating the exercise of market power in these markets; and the development of procedures for defining new capacity zones. My *curriculum vita* is attached as Exhibit A.

OVERVIEW

9. In response to a request for proposal ("RFP"), issued subject to a January 18, 2013 order issued by the Public Service Commission ("Commission") instituting proceedings in

this docket, Niagara Mohawk Power Corporation d/b/a National Grid ("National Grid") received several proposals from NRG Energy ("NRG") to repower existing generators at Dunkirk. Under one proposal ("Option 1"), a new combined cycle generator would be built at the Dunkirk site, while the existing Dunkirk Unit 2 would be refueled to use natural gas. Under another proposal ("Option 2"), Dunkirk Units 2, 3 and 4 would be refueled using natural gas.[1]

10. National Grid retained PA Consulting ("PA") to review these proposals, and to compare them to a base case in which National Grid would implement certain upgrades to the transmission system that are deemed necessary in the event that all of the Dunkirk units are retired. In this affidavit, I will describe the procedures that I believe the Commission should use to determine whether generation investment is in the interest of electricity consumers, and the rationale for using those procedures. I will also illustrate the application of those procedures to Option 1 and Option 2, and demonstrate whether either option is in the interest of electricity consumers in New York State, based upon the analysis performed by PA.

APPROPRIATE CRITERIA FOR DETERMINING WHETHER GENERATION INVESTMENT IS IN THE INTEREST OF CONSUMERS

Economically Efficient Entry

11. In order to determine whether the addition of a generator is economically efficient, it is useful to conduct a thought experiment. Suppose that a single entity consumes all of the energy produced on the system and owns all of the generation on the system. This entity, which is fully informed, wishes to meet its load at the lowest possible cost (while also preserving reliability in the same manner as used in the current New York State electricity system). Would

[1] NRG also proposed an Option 3. National Grid determined that Option 3 was not responsive to the RFP, so I do not consider it in this affidavit.

that entity want to invest the funds necessary to pay for the new generation? If so, adding that generator is economically efficient. If not, adding that generator is economically inefficient.

12. It would be in the interest of such an entity to make this investment if the net present value of the costs it would incur to develop and construct such a generator, and the fixed operating costs it would incur while that generator was in service, were expected to be less than the net present value of the benefits it expects to realize as a result of the addition of that generator. While other benefits are possible, most of the benefits from a new generator would generally consist of (1) reduction in energy production costs, including both fuel and emissions costs, and (2) the value of the additional installed capacity provided by that generator, which could permit other capacity to be displaced.[2] If the sum of the expected net present value of the net reduction in energy production costs resulting from the addition of a generator and the expected net present value of the capacity provided by that generator is greater than the sum of the net present value of developing and constructing that generator and the net present value of the fixed operating costs associated with operating that generator, then development of that generator is economically efficient and the entity would proceed with it.

13. Of course, there is no single entity who owns all of the generation and consumes all of the energy in New York. There are many consumers of energy, and ownership of generation is also dispersed. Yet the conclusion reached above still stands. Over the long term, the amounts paid by electricity customers will have to be high enough to induce the owners of existing resources to remain in the electricity market, and to induce developers to build new resources when it is economically efficient for them to do so. In other words, the total amount

[2] A new generator could reduce the cost of providing ancillary services, such as operating reserves and regulation. It could also permit additional price-sensitive load to be served through reduced energy prices, and to the extent that the value that consumers place upon that energy exceeds the cost of producing that energy, that would be another benefit resulting from addition of the new generator. It is unlikely that either of these factors would significantly affect the results of the analysis to follow, so I will disregard them going forward.

paid by electricity consumers, over the long run, must equal the cost of developing and constructing generation, and of operating generation to meet consumers' needs. A new generator may result in reductions in the total cost of operating generators, and may also cause some existing capacity to be displaced. If the cost of developing and constructing that generator and the fixed operating costs incurred when that generator is in service are less than the sum of (1) the reduction in energy production costs resulting adding that generator and (2) the value of the capacity provided by that generator, then the total amount that consumers must pay over the long run will fall. They will benefit from the fact that economically efficient generation has been added. By the same token, if economically inefficient generation were to be added, consumers would be harmed, because they, in the long run, have to shoulder these costs, and the cost of the new generation would exceed the value of the benefits provided by that new generation.

Impact of Entry on Prices

14. In competitive electricity markets, such as those operated by the NYISO, the entry of new generation can have a significant impact on prices of energy and capacity. As a result, if one were to assume that this impact would be significant and long-lasting, one might reach the conclusion that economically inefficient entry was in the interest of consumers, because it would suppress the prices that consumers pay, not just for energy and capacity provided by the new generator, but for energy and capacity provided by all generators. Such a conclusion would be shortsighted, however. Economically inefficient entry is likely to lead to responses by the owners of competing resources that would offset the impact on energy and capacity prices resulting from the inefficient entry. As a result, if economically inefficient entry is supported by contracts that require consumers to pay above-market prices for the energy and capacity

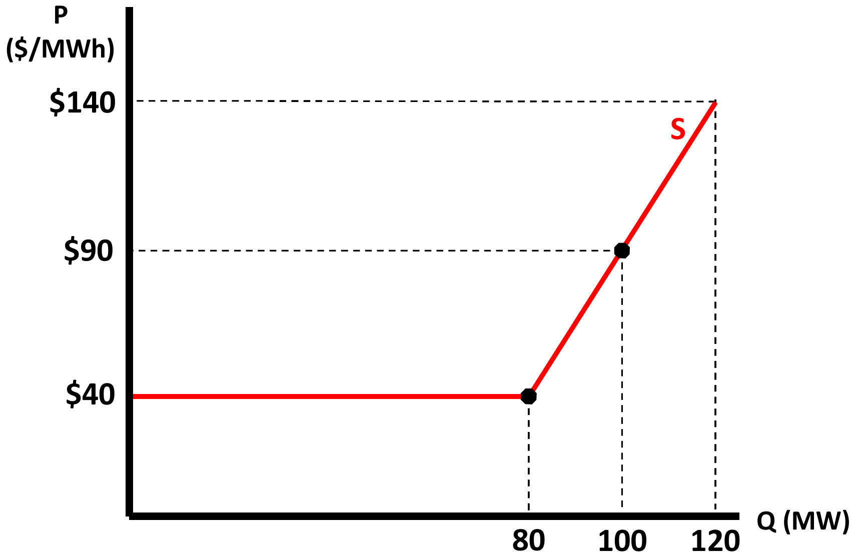
provided by a new generator, it may cause consumers to be worse off in both the short run and the long run.

Assumptions for Illustrative Example

15. An example will help to illustrate this point. Assume that a given 30-day month (720 hours) consists of 100 high-load hours and 620 low-load hours. Load in each high-load hour is 10,000 MW, and load in each low-load hour is 8000 MW.

16. Also assume that there are 100 generators available to meet load on this system. Each of these generators has a maximum generating capacity of 120 MW, and each can produce up to 80 MW at a variable cost of $40/MWh. At output rates above 80 MW, the variable cost begins to rise at a rate of $2.50/MWh for each additional MW of output, as the generator becomes less efficient, ultimately reaching $140/MWh at its maximum output level. Fig. 1 shows the resulting energy supply curve for each of these generators as a function of its output rate.

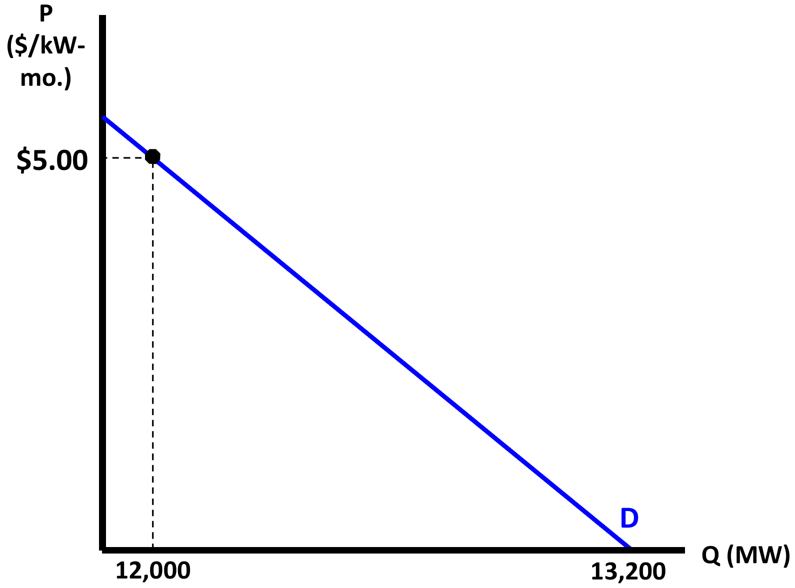
Fig. 1: Energy Supply Curve for Generators in Illustrative Example



17. Also assume that each of these generators incurs fixed operating costs of $1,050,000 per month that can be avoided if that generator were to be mothballed, in which case it could not provide energy or capacity.

18. Next, assume that the NYISO's capacity market uses the demand curve shown below in Fig. 2, so that the price of capacity is $5/kW-mo. when 12,000 MW of capacity are supplied, declining linearly to a price of zero when 13,200 MW or more of capacity are supplied.

Fig. 2: Capacity Demand Curve for Illustrative Example



19. Lastly, to simplify the example, assume there are no transmission losses nor any transmission congestion, so that the location of generators and loads can be disregarded; ignore complicating factors such as ancillary services requirements, minimum generation levels, and minimum run times; and assume that all market participants act in a competitive manner (*i.e.*, their bids reflect their actual costs, and they do not attempt to exercise market power).

<u>Equilibrium Before Entry</u>

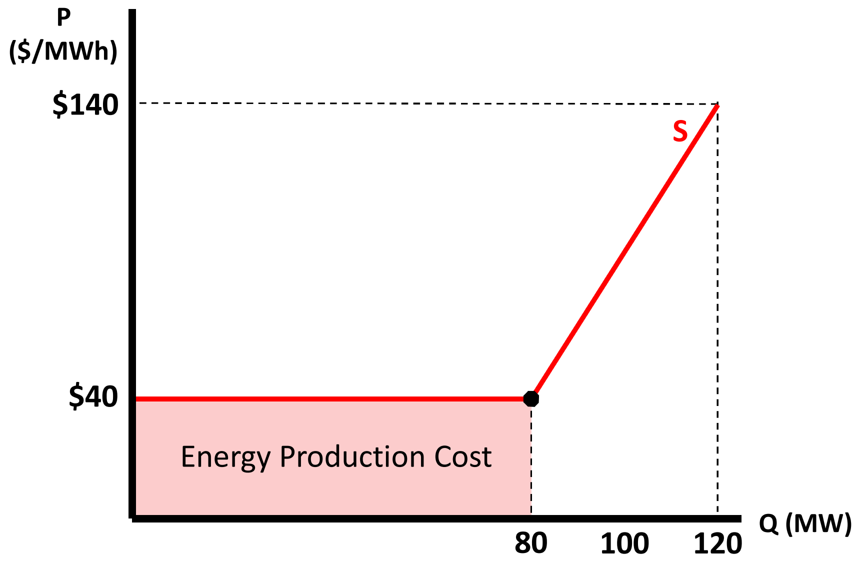
20. During low-load hours, each of the generators will operate at 80 MW, so that in total, these generators will produce 80 MWh × 100 generators = 8000 MWh of energy per hour,

enough to meet load. As shown in Fig. 1, when each of these generators operates at 80 MW, its marginal cost of producing energy is $40/MWh, so the price of energy in low-load hours will be $40/MWh.

21. During high-load hours, each of the generators will operate at 100 MW, so that in total, these generators will produce 100 MWh × 100 generators = 10,000 MWh of energy per hour, enough to meet load. As shown in Fig. 1, when each of these generators operates at 100 MW, its marginal cost of producing energy is $90/MWh, so the price of energy in high-load hours will be $90/MWh.

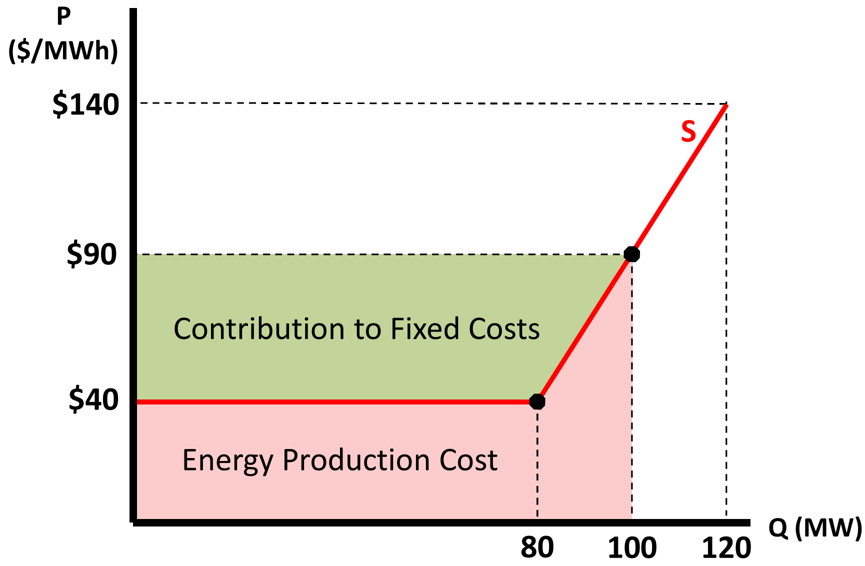
22. The energy production cost incurred by each generator in each hour is simply the area under that generator's energy supply curve to the left of that generator's output level. As Fig. 3 shows, in each low-load hour, each of these generators incurs 80 MWh × $40/MWh = $3200 in energy production cost. Since the energy revenue earned by each generator in each of these hours is also 80 MWh × $40/MWh = $3200, none of these generators earns any contribution towards their fixed operating costs in low-load hours.

Fig. 3: Energy Production Cost for Generators in Low-Load Hours



23. Fig. 4 shows the energy production cost incurred by each generator in each high-load hour, which is $4500.[3] Since the energy revenue earned by each generator in each of these hours is 100 MWh × $90/MWh = $9000, each of these generators earns a contribution of $9000 – $4500 = $4500 towards its fixed operating costs in high-load hours, as shown in Fig. 4. Over the course of the month, that will sum to $4500 × 100 hours = $450,000 for each generator.

Fig. 4: Contribution to Fixed Costs for Generators in High-Load Hours



24. Finally, with 100 generators, a total of 12,000 MW of capacity are provided.[4] As Fig. 2 showed, at that level of capacity, each generator will receive $5/kW-mo. × 120 MW = $600,000 per month in capacity revenue. In conjunction with the $450,000 per month in energy margins, each of these generators receives a total of $1,050,000 in contributions towards its fixed costs. Since each of these generators incurs $1,050,000 in fixed operating costs to remain in service each month, the market is in equilibrium. If there were fewer generators, there would be

[3] The hourly energy production cost for each of these generators is the area of the shaded region below the supply curve and to the left of 100 MWh of output, which is $3200 + 20 MW × ($40/MWh + $90/MWh) / 2 = $4500.

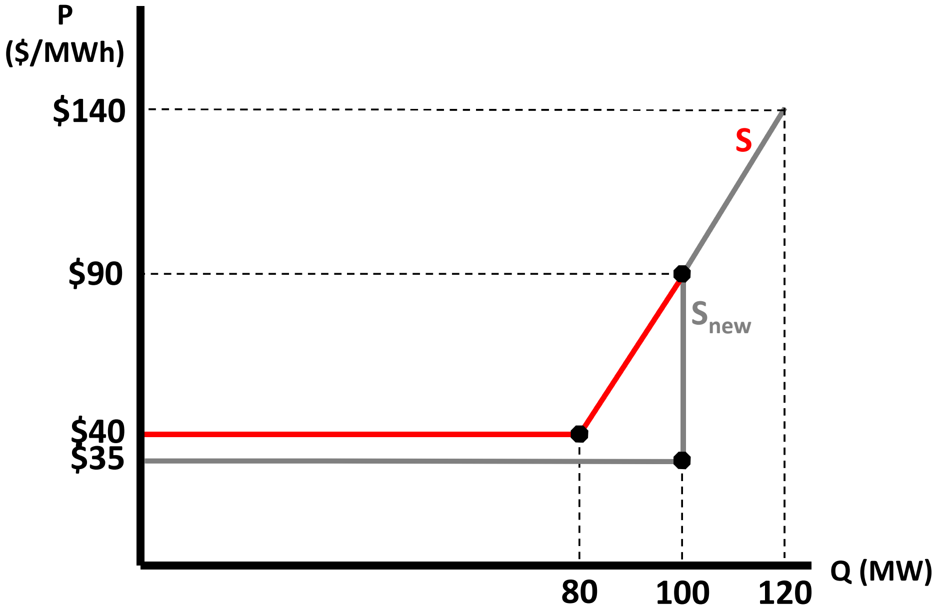
[4] As I will describe later, the NYISO's capacity market actually uses a metric called unforced capacity ("UCAP"), which is generally less than a given generator's generating capability, to determine the amount of capacity provided by a generator. I will ignore the distinction for this illustrative example.

an incentive to add generation. If there were more generators, there would be an incentive to retire generation.

Impact of Entry on Pre-Existing Generators

25. Next, assume that a new 120 MW generator enters service. It is more efficient than the existing generators, in that it can produce up to 100 MW at a variable cost of $35/MWh. Above 100 MW, it has the same variable costs as the existing generators. Its energy supply curve (S_{new}), along with the energy supply curve for the pre-existing generators (S), is shown in Fig. 5.

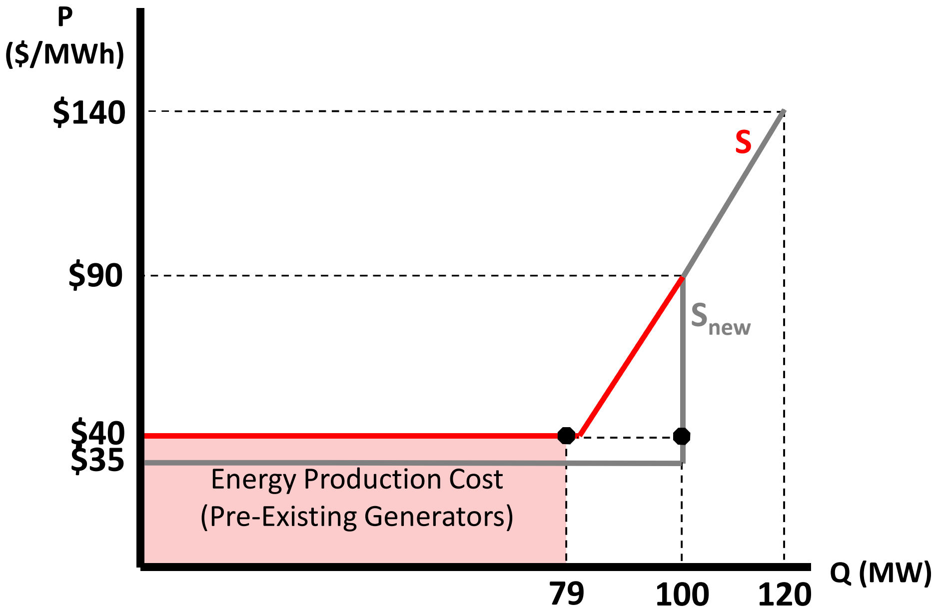
Fig. 5: Energy Supply Curves for Pre-Existing and New Generators



26. Because it can operate at a lower cost, the new generator will operate at 100 MW in every hour, leaving 7900 MW of load to be met by pre-existing generators in low-load hours, and 9900 MW of load to be met by pre-existing generators in high-load hours. Nevertheless, the price of energy in low-load hours will remain $40/MWh, because there are 8000 MW of generating capacity available on pre-existing generators at a cost of $40/MWh, and only 7900

MW of that capacity is needed. The pre-existing generators will operate at an average output level of 7900 MW / 100 generators = 79 MW, so each such generator will incur energy production costs of 79 MWh × \$40/MWh = \$3160, on average, as shown by the rectangle in Fig. 6. But the energy revenue earned by each such generator in each low-load hour will average 79 MWh × \$40/MWh = \$3160, so once more, none of the pre-existing generators earns any contribution towards their fixed operating costs in low-load hours.[5]

Fig. 6: Energy Production Cost for Pre-Existing Generators in Low-Load Hours



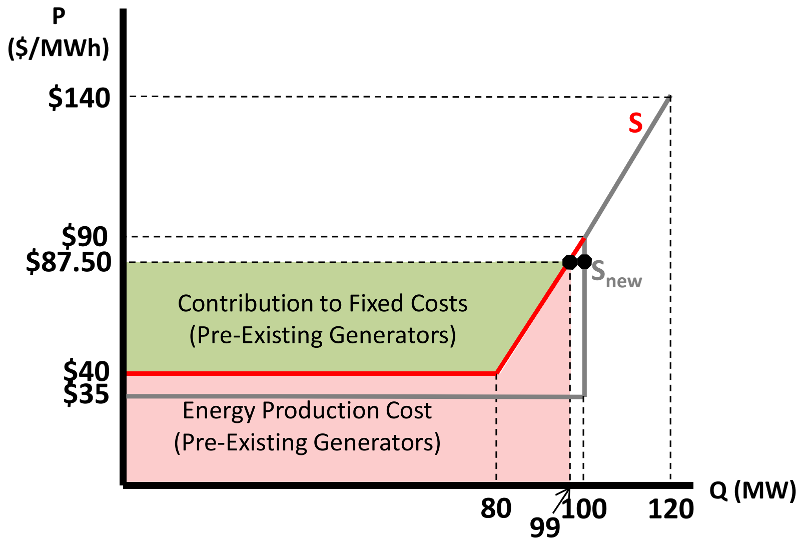
27. As Fig. 7 shows, in high-load hours, each pre-existing generator will be directed to operate at 9900 MW / 100 generators = 99 MW, rather than 100 MW. The 1 MW reduction in each such generator's output level reflects the output of the new generator, which reduces the need for pre-existing generators to produce as much energy as before. This reduction in the pre-existing generators' output will cause the price of energy to drop from \$90/MWh to

[5] Some of the pre-existing generators may operate at more than 79 MW while others may operate at less than 79 MW, but none of them will earn any contribution towards their fixed operating costs in low-load hours.

$87.50/MWh, which is the marginal cost of output for the pre-existing generators when they operate at 99 MWh, as shown in Fig. 7.

28. The reduction in output causes the energy production cost incurred by each pre-existing generator in each high-load hour to fall to $4411.25.[6] Since the energy revenue earned by each pre-existing generator in each high-load hour is 99 MWh × $87.50/MWh = $8662.50, each of these generators earns a contribution of $8662.50 – $4411.25 = $4251.25, as shown in Fig. 7, towards its fixed operating costs in each high-load hour, or $425,125 per month.

Fig. 7: Contribution to Fixed Costs for Pre-Existing Generators in High-Load Hours

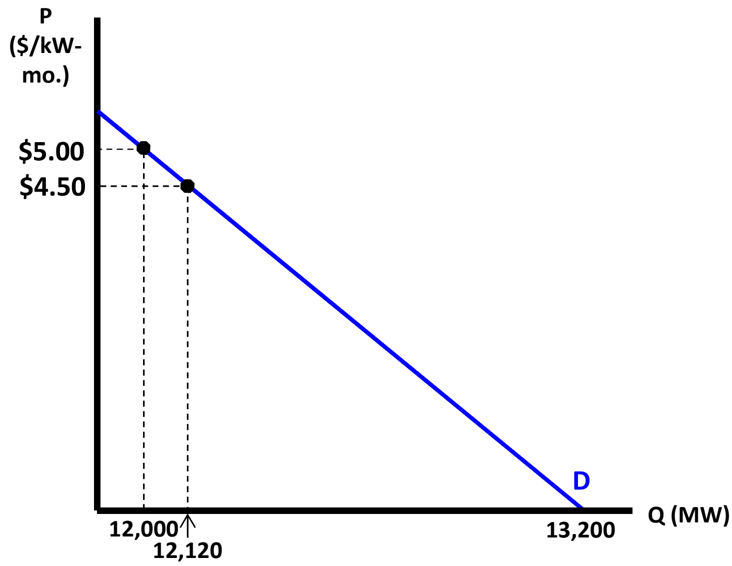


29. The addition of the new generator will also affect capacity prices. With 101 generators, a total of 12,120 MW of capacity is provided, which as Fig. 8 shows, will cause the price of capacity to fall to $4.50/kW-mo. Consequently, the capacity revenue that each pre-existing generator receives will fall to $4.50/kW-mo. × 120 MW = $540,000 per month in capacity revenue. In conjunction with the $425,125 per month in energy margins, each pre-existing generator receives a total of $965,125 in contributions towards its fixed costs, which is

[6] The hourly energy production cost for each of these generators is the area of the shaded region below the supply curve and to the left of 99 MWh of output, which is now $3200 + 19 MWh × ($40/MWh + $87.50/MWh) / 2 = $4411.25.

less than the $1,050,000 in fixed operating costs that each generator incurs. Consequently, this is not an equilibrium. There is an incentive to retire or mothball pre-existing generation, thereby avoiding these costs, which would make the owner of the retired or mothballed generator better off.

Fig. 8: Capacity Market After Entry of New Generator



Equilibrium After Entry and Retirement

30. If one of the pre-existing generators is retired or mothballed, then during low-load hours, the new generator will continue to operate at 100 MW in all hours, leaving 7900 MW of load to be met by pre-existing generators in low-load hours, and 9900 MW of load to be met by pre-existing generators in high-load hours. The price of energy in low-load hours will remain $40/MWh, because even with the retirement, there are 8000 MW – 80 MW = 7920 MW of generating capacity available on pre-existing generators at a cost of $40/MWh, and only 7900 MW of that capacity is needed. The remaining pre-existing generators will operate at an average of 7900 MW / 99 generators = 79.8 MW, so each such generator will incur an average of 79.8 MWh × $40/MWh = $3192 in variable costs to generate energy. But the energy revenue earned

by each such generator in each low-load hour will also average 79.8 MWh × $40/MWh = $3192, so again, none of the pre-existing generators earns any contribution towards its fixed operating costs in low-load hours.

31. During high-load hours, each of the remaining pre-existing generators will operate at 9900 MW / 99 generators = 100 MW, thereby producing 9900 MWh of energy in each such hour. The price of energy will return to $90/MWh, since that is the marginal cost of operation for these generators at an output level of 100 MW. Each of these generators will incur $4500 in variable costs in each high-load hour to generate energy, just as it did in high-load hours before the entry of the new generator and the retirement of one of the pre-existing generators. Likewise, each of these generators will receive $9000 in energy revenue, just as it did before the entry and the offsetting retirement. Consequently, each of these generators earns a contribution of $9000 – $4500 = $4500 towards its fixed operating costs in high-load hours, which sums to $450,000 over the course of the month.

32. The retirement of one of the pre-existing generators will also cause capacity prices to rebound to pre-entry levels. A total of 12,000 MW of capacity is provided, so, as Fig. 2 showed, at that level of capacity, each generator will receive $5/kW-mo. × 120 MW = $600,000 per month in capacity revenue. In conjunction with the $450,000 per month in energy margins, each pre-existing generator receives a total of $1,050,000 in contributions towards its fixed costs. Since each of these generators incurs $1,050,000 in fixed operating costs, the retirement of one of the pre-existing generators has offset the entry of the new generator and returned the market to a state of equilibrium.

Impact on Customer Costs

33. Table 1 shows the total amount that consumers would pay for energy and capacity purchased from pre-existing generators under three scenarios: (1) at the equilibrium energy and capacity prices before entry of the new generator; (2) at the energy and capacity prices that would result after entry of the new generator, if that entry did not induce any retirements; and (3) at the energy and capacity prices that would result after one of the pre-existing generators retires, and the market returns to equilibrium. It also shows the value of the energy and capacity provided by the new generator in the latter two scenarios.

Table 1: Impact of Entry and Retirement on Payments to Pre-Existing Generators and the Market Value of Energy and Capacity Provided by the New Generator

	Payments to Pre-Existing Generators			Market Value of Services Provided by New Generator	
	Before Entry	After Entry, Assuming No Retirement	After Entry and Offsetting Retirement	After Entry, Assuming No Retirement	After Entry and Offsetting Retirement
Energy Market in Low-Load Hours					
Number of Hours	620	620	620	620	620
Hourly Energy Purchases (MWh)	8,000	7,900	7,900	100	100
Energy Price ($/MWh)	40.00	40.00	40.00	40.00	40.00
Payment by Load ($000)	198,400	195,920	195,920	2,480	2,480
Energy Market in High-Load Hours					
Number of Hours	100	100	100	100	100
Hourly Energy Purchases (MWh)	10,000	9,900	9,900	100	100
Energy Price ($/MWh)	90.00	87.50	90.00	87.50	90.00
Payment by Load ($000)	90,000	86,625	89,100	875	900
Capacity Market					
Capacity Purchases (MW-mo.)	12,000	12,000	11,880	120	120
Capacity Price ($/kW-mo.)	5.00	4.50	5.00	4.50	5.00
Payment by Load ($000)	60,000	54,000	59,400	540	600
Total Payments by Load ($000)	348,400	336,545	344,420	3,895	3,980
Difference ($000)		11,855	3,980		

34. As Table 1 shows, any assessment of the impact on consumers that assumes that entry will suppress entry on energy and capacity prices, without considering the impact of the competitive response that entry is likely to induce, may produce misleading results, as the anticipated impact on prices may be ephemeral. In this example, if energy prices were to fall to

$87.50/MWh in high-load hours and capacity prices were to fall to $4.50/kW-mo., as they would in this example if the competitive response is ignored, then the total amount paid to pre-existing generators falls by $11,855,000 per month. This might lead one to conclude that consumers would come out ahead even if the new generator were paid far more than the market value of the energy and capacity that it provides, which is $3,895,000. As long as the payments to the new generator were less than $11,855,000, consumers would benefit, according to that logic.

35. But that conclusion would be incorrect. As Table 1 demonstrates, once the impact of the retirement of one of the money-losing pre-existing generators that was prompted by the entry is taken into account, the total amount paid to pre-existing generators falls by only $3,980,000 per month. This matches the market value of the energy and capacity provided by the new generator (which increases slightly after the retirement of one of the pre-existing generators). Consequently, in this example, any contract that pays the new generator more than the market value of its services will leave consumers worse off than they would have been without the entry of the new generator.

Applying the Correct Procedure for Determining Whether Addition of the New Generator Is in the Interest of Consumers

36. The procedure that I recommend for assessing whether a new generator is in consumers' interests would not yield such misleading results. I will illustrate how it would be applied in this example in two different scenarios. In Scenario 1, the developer of the new generator does not retain the rights to any revenue from services to be provided by that generator. In Scenario 2, the developer of the new generator retains the rights to revenue from the sale of energy (but not capacity) to be provided by that generator. In either scenario, the developer must pay the costs of developing and constructing that generator, and the fixed operating costs associated with keeping it in service.

Scenario 1: Developer Does Not Retain Energy Revenue

37. In the first scenario, since the only payments the developer receives are the ones it is entitled to under the contract, it is relatively easy to determine the cost of developing and constructing the new generator and the fixed operating costs associated with operating that generator. It is simply the contract payment to be made to the developer.[7] Therefore, if the contract payment made to the developer is less than the net benefits provided by that generator, which is the sum of the reduction in energy production costs resulting from the addition of this generator and the value of the capacity provided by that generator, then development of that generator is economically efficient and should proceed, since this means that the costs of developing and constructing the new generator and the fixed operating costs associated with operating that generator must be less than the net benefits provided by that generator.

38. In Table 2, I calculate the impact of entry of this new generator on energy production costs. During each low-load hour, energy produced by this new generator, which costs $35/MWh, would displace 100 MWh of energy produced by pre-existing generators whose average cost is $40/MWh, thereby yielding a reduction of $310,000 in the energy production cost over the course of the month. In addition, during each high-load hour, energy produced by this new generator would displace 100 MWh of energy produced by pre-existing generators. Since those generators avoid an average of $88.75/MWh in costs as a result of being dispatched down,[8] the addition of the new generator yields a $537,500 monthly reduction in energy production costs. Finally, the value of the capacity produced by the new generator is $540,000. These

[7] Since my example only considers one month, I have dispensed with the net present value aspect of these calculations in this section. Later, when evaluating Option 1 and Option 2, I will include net present values.

[8] Each pre-existing generator is dispatched down from 100 MW, where its variable cost is $90/MWh, to 99 MW, where its variable cost is $87.50/MWh. Since the energy supply curves for these generators are straight lines, the cost that each avoids incurring as a result of having been dispatched down by 1 MW is ($87.50/MWh + $90/MWh) / 2 = $88.75/MWh.

imply that in order for the addition of this capacity to be economically efficient, the contract payments to the developer of this generator should not exceed the net benefits provided by that generator, which are $310,000 + $537,500 + $540,000 = $1,387,500.

Table 2: Calculation of the Maximum Contract Payment the Developer of the New Generator Can Receive if the Addition of that Generator is to be Economically Efficient (Scenario 1)

Net Benefits Produced by the New Generator	
Low-Load Hours	
Number of Hours	620
Hourly Energy Sales (MWh)	100
Avg. Energy Production Cost for Pre-Existing Gens. ($/MWh)	40.00
Energy Production Cost ($/MWh)	35.00
Reduction in Energy Production Cost ($000)	310.0
High-Load Hours	
Number of Hours	100
Hourly Energy Sales (MWh)	100
Avg. Energy Production Cost for Pre-Existing Gens. ($/MWh)	88.75
Energy Production Cost ($/MWh)	35.00
Reduction in Energy Production Cost ($000)	537.5
Capacity	
Capacity Sales (MW-mo.)	120
Capacity Price ($/kW-mo.)	4.50
Value ($000)	540.0
Maximum Contract Payment to Developer ($000)	**1,387.5**
Energy Production Cost in High-Load Hours ($000)	2,170.0
Energy Production Cost in Low-Load Hours ($000)	350.0
Total Energy Production Cost ($000)	2,520.0
Total Cost of Services Provided by New Generator ($000)	**3,907.5**

39. As Table 2 also shows, if the energy production costs incurred by this new generator, which Table 2 shows are $2,520,000, are added to this maximum contract payment to the developer, the total cost associated with developing, building and operating this generator sums to $3,907,500, which only slightly exceeds the $3,895,000 market value of the services provided by the new generator, as calculated in Table 1. Consequently, while using this approach to determine whether contract payments to developers are justified would ensure that

generation is added only when doing so is in consumers' interest, it would also ensure that the total amount paid for the services provided by the new generator is consistent with their market value.[9]

Scenario 2: Developer Retains Energy Revenue

40. If the developer retains the energy revenue produced by the new generator (as NRG proposes for one of the generators to be built under Option 1, and for all of the generators to be built under Option 2), the developer no longer expects to recoup all of the costs associated with developing, constructing and operating the new generator solely from payments made directly to it. It may also recover some of those costs through energy sales. Consequently, the cost of developing and constructing that generator and the fixed costs associated with operating the generator are likely to exceed the contract payment that would be made to the developer. Instead, a better estimate of those costs is the sum of the contract payment to be made to the developer and the energy margins on energy sales from that generator that the developer expects to retain.

41. The analysis in the preceding section determined that the new generator in this example would be an economically efficient addition if the cost of developing and constructing that generator and the fixed costs associated with operating the generator did not exceed $1,387,500. Table 3 calculates the margins on energy sales that the developer would realize if it were to retain the right to the revenue from energy produced by the new generator. As it shows, those margins sum to $835,000 over the course of the month. Therefore, in this case, addition of

[9] The $12,500 difference between the market value of the services provided by the new generator and the net benefits provided by that generator is attributable to the new generator's impact on the price of energy during high-load hours. It causes that price to decrease to $87.50/MWh, so the new generator will receive only $87.50/MWh for energy produced during those hours. But the cost that other generators avoid incurring due to the entry of the new generator averages $88.75/MWh. Consequently, there are ($88.75/MWh – $87.50/MWh) × 100 MWh × 100 hrs. = $12,500 in cost reductions that result from the entry of the new generator that are not captured by its owner.

this generator would be economically efficient if the contract payment to the developer does not exceed $1,387,500 – $835,000 = $552,500, since that would indicate that the cost of developing and constructing that generator and the fixed costs associated with operating the generator were no more than $1,387,500.

Table 3: Calculation of the Maximum Contract Payment the Developer of the New Generator Can Receive if the Addition of that Generator is to be Economically Efficient (Scenario 2)

Energy Margins Realized by the New Generator	
Low-Load Hours	
Number of Hours	620
Hourly Energy Sales (MWh)	100
Energy Price ($/MWh)	40.00
Energy Production Cost ($/MWh)	35.00
Margin ($000)	310.0
High-Load Hours	
Number of Hours	100
Hourly Energy Sales (MWh)	100
Energy Price ($/MWh)	87.50
Energy Production Cost ($/MWh)	35.00
Margin ($000)	525.0
Total Energy Margin ($000)	**835.0**
Reduction in Energy Production Cost ($000)	847.5
Capacity Value ($000)	540.0
Less: Total Energy Margin ($000)	(835.0)
Maximum Contract Payment to Developer ($000)	**552.5**
Payments for Energy Produced by New Generator ($000)	
During Low-Load Hours	2,480.0
During High-Load Hours	875.0
Total Cost of Services Provided by New Generator ($000)	**3,907.5**

42. The bottom portion of Table 3 adds the cost of purchasing energy produced by this generator to this maximum contract payment to the developer, and shows that the total cost associated with developing, building and operating this generator once again sums to $3,907,500, just as in Table 2. Once more, using this approach to determine whether contract payments to developers are justified would ensure both that generation is added only when doing so is in

consumers' interest and that the total amount paid for the services provided by the new generator is consistent with their market value.

43. Comparing these calculations to those in Table 2 makes it clear that if an investment is deemed economically inefficient using the test described above in Scenario 1, when the developer did not retain the energy margins, it will certainly be economically inefficient in Scenario 2, when the developer retains those margins. The test described in Scenario 1 found that investment in the generator was economically inefficient if the developer was paid more than $1,387,500 per year. In that case, it would certainly remain economically inefficient in Scenario 2, since the maximum contract payment that the developer can receive decreases to $552,500, with the $835,000 difference reflecting the expected energy margins.

Short-Term Considerations

44. The preceding discussion has concerned what economists call the long-run equilibrium, showing that in the long-run equilibrium, whether generation investment is in the interest of consumers must depend upon whether the investment in that generation is efficient. However, markets are seldom, if ever, in the long-run equilibrium state; while that is the condition that they are always headed for, various factors knock them off course. This prompts the question as to whether, and how, short-term deviations from long-run equilibrium conditions should be taken into account when assessing whether generation investment is in the interest of consumers.

45. I believe that is appropriate to take short-term deviations from long-run equilibrium conditions into account when calculating the factors described above that feed into the determination of whether a generation investment is economically efficient. Suppose, for example, that a proposed new generator is expected to produce $5,000,000 per year in reductions

in energy production cost in the long-run equilibrium, but that due to certain short-run disequilibrium conditions, if development of that generator were to begin right now, it would only produce $1,000,000 in reductions in energy production cost in its first year in service. The assessment of whether that generation investment is economic right now should not assume that it would save $5,000,000 when it starts operation, because it is not actually expected to do that, and assuming otherwise could lead to the conclusion that the investment would be economically efficient when in fact it would not be.[10]

46. However, I do not think it would be appropriate to take any claimed short-term impact of entry on energy or capacity prices into account in this assessment, for two reasons. First, given current conditions in the New York market, I think it is unlikely that an investment in additional generation could have a significant and persistent impact on capacity prices without inducing some offsetting response, like the retirement of one of the pre-existing generators discussed in the previous example. If the market were in a position where prices were higher than needed to keep existing capacity in service, then in theory entry could reduce those prices without inducing such a response. But the fact is that there have been numerous generator retirements or mothballings in New York in recent years, many in the Rest of State ("ROS") region in which the Dunkirk generators to be developed under Options 1 or 2 would be located,[11] so it seems unlikely that reductions in capacity prices resulting from the addition of new generation would not prompt additional retirements or mothballing.

[10] My understanding of the procedures that PA used to calculate the impact that Options 1 and 2 would have on the net present value of energy production costs, which is used in the assessment of those options later in this affidavit, indicates that it is generally consistent with this approach. *See* PA Consulting, National Grid: Analysis of Dunkirk Repowering Options (May 15, 2013) ("PA Report"), App. B-4.

[11] The 2013 edition of Load and Capacity Data (a k.a. the "Gold Book"), available at http://www.nyiso.com/public/webdocs/markets_operations/services/planning/Documents_and_Resources/Planning_Data_and_Reference_Docs/Data_and_Reference_Docs/2013_GoldBook.pdf, states, "Twenty-three generating facilities totaling 1,694 MW of Summer Capability have either retired or provided notice of retirement during 2013 since the publication of the 2012 report…." Gold Book at 21.

47. The time lag associated with the development of new generation also does not provide any reason to believe that entry would have a significant effect on prices, even in the short run. Under Options 1 and 2, it would take from two to four years for NRG to bring new generation into service, while existing generators can retire with six months' notice. If the two were reversed, so that generation could be brought into service more quickly than existing generators could react to the planned entry by retiring or mothballing, one might be able to make the case that for a short period of time—*i.e.,* until existing generators could react to entry by mothballing or retiring their units—entry could temporarily suppress prices below the levels required to keep existing generation in service. But that is not the case.

48. The second, and more fundamental, reason why I do not believe that the assessment of whether investment in new generation is in consumers' interests is that it would undermine the operation of competitive electricity markets, which would harm consumers in the long run.

Impact of Subsidized Economically Inefficient Entry on Other Prospective Entrants

49. One of the lessons that can be gleaned from the illustrative example above is that competitive markets will not support economically inefficient entry. Table 2 demonstrated that addition of the new generator would reduce energy production costs by $847,500, and would provide capacity worth another $540,000, thereby producing net benefits worth $1,387,500. Consequently, if the developer of that new generator cannot cover the costs of developing and constructing that facility, and the fixed costs associated with operating it, for $1,387,500 per month, then development of the new generator is economically inefficient. But development of an economically inefficient facility also would not be in the financial interest of a developer that assumes all costs and retains all revenues associated with the new generator. As Table 3 showed,

the developer of such a generator could only expect to net $835,000 on margins on the sale of energy produced by that generator after accounting for energy production costs. Adding the $540,000 in capacity payments it would expect to receive would leave that developer with $1,375,000 in revenue each month, which is not enough to cover its costs to develop and construct that facility, and the fixed costs associated with operating it, which must be more than $1,387,500 (since addition of the generator was assumed to be economically inefficient).

50. Suppose that economically inefficient entry is supported anyway, through arrangements that cover the costs incurred by a developer of a new generator when the market prices determined for the services that generator provides are not sufficient to cover those costs. That would suppress the prices that other entrants rely upon, which will discourage entry. Another developer, who might have been willing to enter the market because the market prices of energy and capacity determined in a competitive framework would have been sufficient to cover the costs it would incur to build a new generator, may now decline to do so because it quite reasonably fears that economically inefficient, subsidized entry will lower those market prices. As a result, such a developer may fear that it would not be able to recover its investment, whereas it would have expected to be able to recover its investment if economically inefficient entry had not been subsidized. Consequently, subsidizing economically inefficient entry will decrease the likelihood that markets are able to support economically efficient entry. This, in turn, could erode many of the gains that were hoped for when competitive electricity markets were first developed, and which provided much of the rationale for the development of those

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electricity markets, as other developers decline to proceed with their development plans unless they also receive similar contracts.[12]

51. This does not mean that there are not any cases where some sort of out-of-market support for new generation is inconsistent with the interests of consumers. There may be some such cases, because while competitive markets will generally support economically efficient entry, on occasion they may fail to do so.[13] In the illustrative example, there was a small difference between the net benefits resulting from the entry of the new generator ($1,387,500) and the revenue it would expect to earn from the sale of the energy and capacity it produced ($1,375,000).[14] As a result, it is possible that the developer of the new generator in that example might require more than $1,375,000, but less than $1,387,500, per month to cover the costs of developing and constructing that facility, and the fixed costs associated with operating it. In that case, a contract to pay that developer enough to proceed with development might be consistent with economically efficient entry, and might therefore be in the interest of consumers.

52. But the key here is that such out-of-market contracts may be in the interests of consumers if addition of the generator is economically efficient but, for some reason, is not supported by the market revenues that generator would earn.[15] They are not in the interest of consumers, and may undermine the operation of competitive electricity markets and the

[12] A similar argument is made in testimony submitted by William Hogan in State of New Jersey Board of Public Utilities Docket No. EO09110920. See Affidavit of William W. Hogan (June 9, 2010), at ¶¶ 29-33, available at http://www.nj.gov/bpu/pdf/energy/WilliamHogan_comments.pdf.

[13] Other circumstances may also support out-of-market support for new generators.

[14] This difference results from the fact that the entry of the new generator reduces energy prices, so that the cost that other generators avoid incurring, because they are dispatched to produce less energy after the new generator enters, exceeds the revenue that the new generator will receive for that energy. See fn. 9 *supra* for a more detailed description of the cause for this difference.

[15] Generally, this would be more likely to happen when a relatively large amount of capacity must be added (in order to take advantage of large economies of scale) in a transmission-constrained area. The combination of the two might lead to a larger impact on energy prices than was shown in the example, and consequently a larger difference between the net benefits resulting from the addition of a new generator and the market revenue that generator could expect to receive.

incentives they provide for merchant generation to enter when it is economically efficient for it to do so, if economically inefficient new generators are added as a result of such contracts.

Impact of Subsidized Economically Inefficient Entry on Other Prospective Entrants

53. Another potential consequence of subsidized economically inefficient entry would be the expansion of entrant mitigation throughout the state. Currently, the NYISO applies entrant mitigation (a.k.a. "buyer-side mitigation") to new generators siting in New York City ("NYC"). The intent of these mitigation measures is to ensure that new generation only enters in NYC if it is economically efficient for it to do so. In approving these measures, the Federal Energy Regulatory Commission ("FERC") found that "all uneconomic entry has the effect of suppressing prices below the competitive level and this is the key element that mitigation of uneconomic entry should address to avoid price suppression."[16]

54. As a consequence of the application of these measures, minimum offer floors have been applied to capacity offers submitted by Astoria Energy II LLC, and similar floors will be applied to capacity offers submitted by Hudson Transmission Partners.[17] These floors may prevent these entities from selling some or all of the capacity those resources are capable of providing.

55. While the Federal Energy Regulatory Commission ("FERC") has yet to act on the filing, the NYISO has proposed expanding these mitigation measures to cover entrants in all new capacity zones,[18] including the new Southeast New York capacity zone that the NYISO recently

[16] *New York Indep. Sys. Operator, Inc.*, 124 FERC ¶ 61,301 (2008) at P 29.

[17] *See* http://www.nyiso.com/public/webdocs/markets_operations/market_data/icap/In-City_Mitigation_Documents/In-City_Mitigation_Documents/NYISO_Notice_of_BSM_Determinations_Nov_6_2012.pdf.

[18] "New York Independent System Operator, Inc., Further Compliance Filing," Docket No. ER12-360-001 (June 29, 2012) ("June 2012 Filing").

proposed.[19] It is therefore possible that the scope of these mitigation measures soon will not be limited to NYC.

56. At the May 9, 2013 meeting of the NYISO's Business Issues Committee, generator interests proposed expanding these entrant mitigation measures even further, so that they would cover entrants in the ROS region (which includes Dunkirk), stating that "nothing … prevents uneconomic entry in the statewide market from occurring."[20] While this motion was tabled,[21] on the next day, Independent Power Producers of New York, Inc., filed a complaint with FERC, proposing to apply buyer-side mitigation measures to capacity offers submitted by existing generators in the ROS region with whom reliability service support agreements are in effect.[22] While IPPNY stated that it does not seek to apply mitigation to entrants in ROS in its complaint, the complaint also warns that IPPNY may file such a complaint with FERC in the future, if what it calls the "looming threat to the capacity market posed by uneconomic entry of new resources"[23] is not resolved to its satisfaction through the NYISO's stakeholder process.

57. If entrant mitigation were applied to the ROS region, as proposed at the Management Committee meeting and suggested by the IPPNY Complaint, it very well might be applied to the generators proposed under Options 1 or 2. While the NYISO's proposal to mitigate entrants in new capacity zones would exempt from entrant mitigation resources that

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[19] "New York Independent System Operator, Inc., Proposed Tariff Revisions to Establish and Recognize a New Capacity Zone and Request for Action on Pending Compliance Filing," Docket No. ER13-1380-000 (Apr. 30, 2013).

[20] TransCanada, "Statewide Capacity Market Mitigation Measures" (May 9, 2013) at 3, available at http://www.nyiso.com/public/webdocs/markets_operations/committees/bic/meeting_materials/2013-05-09/agenda_08_pres_TransCanada_Capacity%20Mitigation%20May%209.pdf.

[21] *See* http://www.nyiso.com/public/webdocs/markets_operations/committees/bic/meeting_materials/2013-05-09/050913_BIC_Final_Motions.pdf, Motion #2a.

[22] "Complaint Requesting Fast Track Processing of the Independent Power Producers of New York, Inc.," Docket No. EL13-62-001 (May 10, 2012) ("IPPNY Complaint").

[23] IPPNY Complaint at 38, fn. 143.

reached certain development milestones at the time the new capacity zone is proposed,[24] it is not clear that the generators that would be built under Options 1 or 2 would qualify for exemptions in the event that similar criteria were adopted. The IPPNY complaint specifically refers to the repowering proposals that are the subject of this docket,[25] so it is reasonable to infer that IPPNY would seek to apply mitigation to Options 1 or 2, should either proceed.

58. Even if entrant mitigation is not applied to Options 1 or 2, the application of entrant mitigation in the ROS region would have adverse impacts. While mitigation may be necessary in cases where competition is limited and incentives to act in anticompetitive ways are strong, mitigation should generally be avoided when these circumstances do not present themselves, because mitigation may inadvertently cause significant harm if it fails to operate as intended, and mitigates offers that should not have been mitigated, unnecessarily interfering in the operation of the market.[26]

59. In particular, application of entrant mitigation in the ROS region may deter economically efficient entry. Under the mitigation measures proposed by the NYISO for new capacity zones, which could potentially be expanded to ROS, entrants in those zones will be subject to an offer floor that is set at the lesser of a unit-specific level that is intended to reflect the cost of developing, constructing and operating that generator less forecasted energy and ancillary services revenue, or a default offer floor. The default offer floor, in turn, is based on the NYISO's calculation of the amount of capacity revenue that would be required to support economically efficient entry. As the NYISO's independent market monitoring unit has

[24] June 2012 Filing at 5-9.

[25] IPPNY Complaint at 19, fn. 62.

[26] The MMU recently made this point with respect to the energy market: "Mitigation measures are intended to mitigate abuses of market power while minimizing interference with the market when the market is workably competitive…. This framework prevents mitigation when it is not necessary to address market power…." 2012 SOM Report at A-43.

acknowledged in recent reports, the NYISO's current capacity demand curves likely overstate the cost of developing additional resources.[27] This, in turn, may cause the default offer floor to exceed the net cost of developing a generator. Therefore, if the NYISO also overestimates the unit-specific net cost of developing a generator, possibly because its expectations regarding future energy and ancillary services revenues are more pessimistic than the developer's projections, the new unit will not be permitted to sell capacity, even if it is economically efficient.

60. For this reason, it is important not to subsidize economically inefficient entry, as that would support claims that the prices in the ROS capacity market have been suppressed below competitive levels, which could increase the likelihood that FERC might agree to impose entrant mitigation in the ROS region.

ASSESSMENT OF WHETHER OPTIONS 1 OR 2 ARE IN THE INTEREST OF CONSUMERS

Assessment of Option 1

61. In order to determine whether Option 1 is in the interest of consumers, it is first necessary to calculate the expected net present value of the capacity that would be provided by the Dunkirk generators. This calculation is presented in Table 4. The left side of that table calculates the value of this capacity in summer months (May through October) of each year, and

[27] "To establish a demand curve, the technology of a hypothetical new entrant must be chosen and the current tariff specifies that this is a peaking unit…. When a demand curve is developed to support investment in a unit that is not the most economic type of unit, investors still have an incentive to invest in the most economic type of unit. As a result, the capacity market may provide incentives to invest when additional investment is not necessary…. Recent demand curve reset studies have shown that the Net CONE of a new peaking installation is higher than for a combined cycle installation under many circumstances." David B. Patton, Ph.D., Pallas LeeVanSchaick, Ph.D., and Jie Chen, Ph.D., "2012 State of the Market Report for the New York ISO Markets" (April 2013) ("2012 SOM Report"), available at http://www.nyiso.com/public/webdocs/markets_operations/committees/mc/meeting_materials/2013-04-24/4_NYISO%202012%20SOM%20Report.pdf,at 54-55.

the middle portion of the table calculates the value of that capacity in winter months (November through April), under the following assumptions:

- The refueled Dunkirk Unit 2 begins to provide capacity on June 1, 2015, and the new combined cycle generator begins to provide capacity on June 1, 2017.
- [redacted]
- [redacted]
- The price of UCAP will reflect the forecasted long-run equilibrium UCAP price in the ROS region (which is where Dunkirk is located) that was anticipated by the NYISO when the UCAP demand curves currently in effect in the NYISO-administered capacity market were developed, escalated at a rate of 2.7 percent per year to account for inflation (the inflation rate used by PA in its forecasts).[30,31]

[28] [redacted]

[29] [redacted]

[30] PA Report at 15.

[31] Under the current UCAP demand curves, the monthly reference point for the NYCA (i.e., the price that will be calculated if the amount of UCAP supplied is equal to the minimum UCAP requirement for the NYCA) is $10.05/kW-mo., declining linearly to a price of zero when the amount of UCAP supplied is equal to 112 percent of the minimum UCAP requirement for the NYCA. (http://www nyiso.com/public/webdocs/markets_operations/market_data/icap/ICAP_Auctions/2013/Summer_2013/Documents/Demand_Curve_Summer_2013_Revised.pdf). However, that demand curve was developed under the assumption that the amount of UCAP supplied in summer months would equal 101.1 percent of the minimum UCAP requirement for the NYCA, on average, in which case the UCAP price would be [(112 – 101.1) / (112 – 100)] × $10.05/kW-mo. = $9.13/kW-mo. on average (stated in terms of 2013 dollars). (*See New York Indep. Sys. Operator, Inc.*, 136 FERC ¶ 61,192 (2011) at PP 32, 54.) It was also developed under the assumption that the amount of UCAP supplied in winter months would be 104.5 percent of the amount of UCAP assumed to be supplied in summer months, on average, in which case the UCAP price would be [(112 – (101.1 x 104.5)) / (112 – 100)] × $10.05/kW-mo. = $5.32/kW-mo. on average (also stated in terms of 2013 dollars). (*See* Request for Leave to

**Table 4: Expected Net Present Value of Capacity
Provided by Dunkirk Generators Under Option 1**

	Summer Months			Winter Months			Annual UCAP Revenue	
Year	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total			**242,173**			**168,363**	**410,536**	**238,797**

62. The right side of Table 4 calculates the net present value of the capacity provided by these generators, using a 7.36 percent per year discount rate, which reflects the average weighted cost of capital of the NYTOs, and is the value used by the NYISO in its 2011 Congestion Assessment and Resource Integration Study.[32] It concludes that the net present value of the capacity to be provided through May 31, 2025, by the Dunkirk units to be built under Option 1 is about $239 million.

63. With this information, one can proceed to determining whether the net benefit of the new generators that would be built under Option 1 exceeds their cost. In the earlier example, I described two ways to apply this test: one for cases when the developer does not retain the revenue for energy produced by the new generator, and another for cases when the developer

Answer and Answer of the New York Independent System Operator, Inc., Docket No. ER11-2224-009 (July 18, 2011) at 3 and *New York Independent System Operator, Inc.* Compliance Filing, Docket No. ER11-2224-010 (Sept. 22, 2011) at 2.)

[32] 2011 Congestion Assessment and Resource Integration Study (Mar. 20, 2012) at 25, available at http://www.nyiso.com/public/webdocs/markets_operations/services/planning/Planning_Studies/Economic_Planning_Studies_%28CARIS%29/Caris_Final_Reports/2011_CARIS_Final_Report__3-20-12.pdf. This is also the value used by PA in its net present value calculations. PA Report at 1, fn. 2.

retains the revenue for energy produced by the new generator. Option 1 is somewhere in between those two cases, in that NRG would retain the revenue for energy produced by the refueled Dunkirk Unit 2, but not the revenue for energy produced by the new combined cycle generator. I will use the first approach to assess whether Option 1 is an economically efficient addition of generation. Consequently, that test will conclude that Option 1 will be an economically efficient investment if the net present value of payments to NRG is less than the net benefits resulting from Option 1, which is the sum of the net present value of the reduction in energy production costs resulting from Option 1 and the net present value of the capacity provided under Option 1. One should keep in mind that this approach was designed for a case when the developer retains none of the energy margins, so it is somewhat biased in favor of finding that Option 1 is economically efficient.

64. PA forecasts that Option 1 would cause energy production costs to be higher than they would be in the base case (which entails certain upgrades to the transmission system). PA estimates the net present value of this increase to be $122 million.[33] Therefore, the net benefits resulting from Option 1, relative to the base case, are $117 million, which is equal to the $239 million value of the capacity that would be provided under Option 1, minus the $122 million adverse impact of Option 1 on energy production costs.

65. This must be compared to the contract payments that would be made to NRG under Option 1. In Table 5, I calculate the net present value of these contract payments. Table 5 uses the same assumptions as Table 4 as to when the refueled Dunkirk Unit 2 and the new combined cycle generator would come into service, but Table 5 calculates the amount that must be paid each month under the contract as 75 MW (for the refueled Dunkirk Unit 2) and 422 MW

[33] PA Report at 10.

(for the new combined cycle plant), multiplied [redacted] (escalated by the inflation rate).[34] The inflation and discount rates used for Table 5 are the same as were used for Table 4.

Table 5: Expected Net Present Value of Contract Payments Under Option 1

			Annual Contract Cost	
Year	Capacity (MW-mo.)	Contract Price ($/kW-mo.)	Nominal ($000)	Discounted ($000)
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]			[redacted]	[redacted]

66. The net present value of these payments through May 31, 2025, which Table 5 calculates as [redacted] must be compared to the cost of implementing the transmission upgrades that would be undertaken in the base case. National Grid has informed me that the cost of those upgrades is $66 million, so the incremental cost of Option 1, relative to the base case, is [redacted] This is much larger than the net benefits that Option 1 would produce. As a result, Option 1 is economically inefficient.

[34] NRG Response to RFP, Att. A.

Table 6: Summary of Analysis of Option 1

NPV of Capacity Revenue ($000)	[redacted]
NPV of Impact on Bid Production Cost ($000)	[redacted]
Net Benefits of Option 1 ($000)	[redacted]
NPV of Payments to NRG ($000)	[redacted]
NPV of Transmission Alternative ($000)	[redacted]
NPV of Incremental Net Cost of NRG Contract ($000)	[redacted]
NPV of Expected Net Gain (Loss) for Consumers ($000)	**(418,022)**

67. If Option 1 were implemented, consumers could expect to bear the net cost of this inefficiency which, as Table 6 shows, is estimated to be about $418 million in net present value terms (stated in 2013 dollars). In truth, the net cost of economically inefficient investment associated with Option 1 is probably larger than this, due to several assumptions in the analysis above which, in order to be conservative, were biased in favor of Option 1. These include the following:

- As discussed above, energy margins that NRG would earn on sales of energy from the refueled Dunkirk Unit 2 were disregarded in this analysis. The cost of developing and constructing Option 1 is actually higher than was assumed here, because this calculation assumed that that cost is simply the net present value of the payments to NRG, but some of those costs will actually be offset by Unit 2's margins.

- The calculation of payments that would be made to NRG also excludes certain other payments, such as property taxes, which NRG would not absorb under its proposal.

- PA's net present value calculations and my calculations in Tables 4 and 5 only go through May 31, 2025. My understanding is that NRG is proposing a [redacted] contract under Option 1, so these calculations do not include the impact of payments under such a contract after May 31, 2025. In 2024 (the last full year in the study period), [redacted] even if Option 1 did not have any adverse impact on energy production costs (relative to the base case), the net benefit under the contract for that year would be negative. It would be reasonable to expect this to continue for the reminder of the contract term, in which case extending the term of the study period would lead to an ever larger difference between the net benefits of Option 1 and the cost of implementing it.

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- The net present value of the capacity that would be supplied under Option 1 may be considerably overstated. In general, prices of UCAP tend to be less than the forecasted long-run equilibrium values. For example, in the just-concluded 2012-13 capability year, the price of UCAP in summer months averaged $2.27/kW-mo., while the price of UCAP in winter months averaged $1.99/kW-mo., compared to forecasted long-run equilibrium values of $8.99/kW-mo. in summer months[35] and $5.12/kW-mo. in winter months.[36] It is therefore likely that Table 4 overstates the value of the capacity that would be provided under Option 1 in the short term at least, and possibly the long term as well if this chronic difference indicates that the NYISO systematically overestimates the cost of providing capacity.

- The comparison of Option 1 to the base case ignores revenues that might offset part of the cost of implementing the transmission upgrades assumed in the base case, such as the incremental transmission congestion contracts which are made available to entities that increase transfer capability. This would reduce the net cost of the base case, thereby increasing the gap between the net benefits of Option 1 and the cost of implementing it.

- Other assumptions listed above may cause the amount of UCAP that can be provided by the Dunkirk units, and hence the net present value of the capacity they provide, to be overstated.

Assessment of Option 2

68. Just as was the case when assessing Option 1, it is necessary to begin the assessment of Option 2 by calculating the expected net present value of the capacity that would be provided by the Dunkirk generators under Option 2. This calculation is presented in Table 7, which is very similar to Table 4. Table 7 is based on the following assumptions:

- All of the Dunkirk generators begin to provide capacity on June 1, 2015.

- They can provide a total of [redacted] in each month.[37]

[35] In summer 2012, the monthly reference point for the NYCA was $9.90/kW-mo. The UCAP demand curve was developed under the assumption that the amount of UCAP supplied in summer months would equal 101.1 percent of the minimum UCAP requirement for the NYCA, on average, in which case the UCAP price would be [(112 – 101.1) / (112 – 100)] × $9.90/kW-mo. = $8.99/kW-mo. on average.

[36] In winter 2012-13, the monthly reference point for the NYCA was $9.68/kW-mo. The UCAP demand curve was developed under the assumption that the amount of UCAP supplied in winter months would equal 104.5 percent of the amount of UCAP assumed to be supplied in summer months, on average, in which case the UCAP price would be [(112 – (101.1 x 104.5)) / (112 – 100)] × $9.68/kW-mo. = $5.12/kW-mo. on average.

[37] [redacted]

- The price of UCAP in 2013 will be \$9.13/kW-mo. in summer months and \$5.32/kW-mo. in winter months in 2013, reflecting the forecasted long-run equilibrium UCAP price for the ROS region anticipated by the NYISO when the UCAP demand curves currently in effect in the NYISO-administered capacity market were developed.

- UCAP prices will rise at 2.7 percent per year to reflect inflation, and the annual discount rate will be 7.36 percent per year, both of which are the values used by PA in its calculations.[38]

Table 7: Expected Net Present Value of Capacity Provided by Dunkirk Generators Under Option 2

	Summer Months			Winter Months			Annual UCAP Revenue	
Year	UCAP Sales (MW-mo.)	UCAP Price (\$/kW-mo.)	UCAP Revenue (\$000)	UCAP Sales (MW-mo.)	UCAP Price (\$/kW-mo.)	UCAP Revenue (\$000)	Nominal (\$000)	Discounted (\$000)
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

69. Table 7 indicates the net present value of the capacity provided through May 31, 2025 by the Dunkirk units to be built under Option 2 is about \$279 million. This is larger than the net present value of the capacity to be provided under Option 1, because the generators come into service more quickly under Option 2.

70. With this information, one can proceed to determining whether the net benefit of the new generators that would be built under Option 2 exceeds their cost. I will use the same test

[redacted]

[38] PA Report at 1, fn. 2, and 15.

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that I used to assess whether Option 1 was economic. Consequently, it will conclude that Option 2 is an economically efficient investment if the net present value of payments to NRG is less than the net benefits resulting from Option 2, which is the sum of the net present value of the reduction in energy production costs resulting from Option 2 and the net present value of the capacity provided under Option 2.

71. PA forecasts that Option 2 would cause energy production costs to be higher than they would be in the base case, and estimates that the net present value of this increase is $430 million.[39] Therefore, the net benefits resulting from Option 2, relative to the base case, are ***negative*** $151 million, because the $430 million adverse impact of Option 2 on energy production costs is $151 million greater than the net present value of the capacity that would be provided under Option 2.

72. Table 8 calculates the expected net present value of the contract payments that NRG would receive under Option 2. Table 8 uses the same assumptions as Table 7 as to when the refueled Dunkirk units would come into service, but Table 8 calculates the amount that must be paid each month under the contract as 455 MW [redacted].[40] The inflation and discount rates used for Table 5 are the same as were used for Table 4.

[39] PA Report at 10.

[40] NRG Response to RFP, Att. B.

Table 8: Expected Net Present Value of Contract Payments Under Option 2

			Annual Contract Cost	
Year	Capacity (MW-mo.)	Contract Price ($/kW-mo.)	Nominal ($000)	Discounted ($000)
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

73. As Table 8 demonstrates, NRG would receive contract payments under Option 2. The net present value of those payments, through May 31, 2025, [redacted] As was the case with Option 1, the net present value of these payments must be compared to the cost of implementing the transmission upgrades that would be undertaken in the base case, and since the cost of those upgrades is $66 million, the incremental cost of Option 2, relative to the base case, is $319 million. Consequently, Option 2 would cost far more than the base case, and would produce negative net benefits relative to the base case. As a result, Option 2 is economically inefficient.

Table 9: Summary of Analysis of Option 2

NPV of Capacity Revenue ($000)	[redacted]
NPV of Impact on Bid Production Cost ($000)	[redacted]
Net Benefits of Option 1 ($000)	[redacted]
NPV of Payments to NRG ($000)	[redacted]
NPV of Transmission Alternative ($000)	[redacted]
NPV of Incremental Net Cost of NRG Contract ($000)	[redacted]
NPV of Expected Net Gain (Loss) for Consumers ($000)	**(470,026)**

74. If Option 2 were implemented, consumers could expect to bear the net cost of this inefficiency which, as Table 9 shows, is estimated to be about $470 million in net present value terms (stated in 2013 dollars). It is likely that the net cost of economically inefficient investment associated with Option 2 will actually be considerably larger than this, because just as in the Option 1 analysis, in order to be conservative, several assumptions in the analysis above were biased in favor of Option 2. These include the following:

- Energy margins that NRG would earn on sales of energy from all of the Dunkirk generators—not just Dunkirk Unit 2, as was the case in the evaluation of Option 1—were disregarded in this analysis. Including these margins would cause the cost of developing and constructing Option 2 to exceed the net present value of the payments to NRG, thereby reducing the amount that could be paid to NRG in order for Option 2 to be economically efficient.

- The calculation of payments that would be made to NRG also excludes certain other payments, such as property taxes, which NRG would not absorb under its proposal.

- The net present value of the capacity that would be supplied under Option 2 may be considerably overstated, for the reasons discussed above in the analysis of Option 1.

- The comparison of Option 2 to the base case again ignores revenues that might offset part of the cost of implementing the transmission upgrades assumed in the base case, which would reduce the net cost of the base case and increase the gap between the net benefits of Option 2 and the cost of implementing it.

- Other assumptions listed above may cause the amount of UCAP that can be provided by the Dunkirk generators, and hence the net present value of the capacity they provide, to be overstated.

CONCLUSION

75. While competitive electricity markets are intended to produce better incentives for developers to choose which generators to develop, and to construct and operate those generators in a cost-effective manner, they do not perform any alchemy that transforms economically inefficient investments into economically efficient ones. If the net benefit—consisting of the impact of a generation investment on energy production costs and the value of the capacity

provided by that generator—is not large enough to support investment of the considerable sums required to develop and construct a generator, and the fixed costs that must be incurred to keep that generator in service, then it is not economically efficient.

76. It is not in consumers' interests in the long run to support the development of economically inefficient generation. Claims may be made that such investment is supported by the impact that the new generation would have on energy and capacity prices, but it is unlikely that such an impact would be significant or long-lived, as pre-existing generators are likely to take actions that would offset the claimed price impact. Moreover, the subsidized development of economically inefficient generation will discourage other developers from proceeding with development that is based on the prices they can obtain in the market, as they may be concerned that those prices will be suppressed through economically inefficient entry in the future. It could also increase the likelihood that entrant mitigation could be applied on a broader basis, which could prevent economically efficient entry in some cases.

77. My analysis of Options 1 and 2, even after making assumptions in the analysis that are very favorable to those options, indicates that the net benefits that would result from either option are much less than the cost of the payments that would be made to NRG under either option. Consequently, either option is economically inefficient, so it would not be in consumers' interests in the long run for the Commission to direct development of either option.

78. This concludes my affidavit.

COMMONWEALTH OF MASSACHUSETTS)
) **ss**
COUNTY OFMIDDLESEX)

I, MICHAEL D. CADWALADER, being first duly sworn on oath depose and say as follows:

I make this affidavit for the purpose of adopting as my sworn testimony in this proceeding the attached material entitled, “Affidavit of Michael D. Cadwalader.”

Further affiant saith not.

Michael D. Cadwalader

On this 17th day of May, 2013, before me, the undersigned notary public, personally appeared Michael D. Cadwalader and acknowledged to me that he/she signed the forgoing document voluntarily for its stated purposes. I identified Michael D. Cadwalader to be the person whose name is signed on the forgoing document by means of the following satisfactory evidence of identity (check one):

___ identification based on my personal knowledge of his/her identity, or

✓ current government-issued identification bearing his/her photographic image and signature.

Notary Public
My commission expires: 07/05/13
(SEAL)

Notary Public
Commonwealth of Massachusetts
My Commission Expires
July 5, 2013

EXHIBIT A

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Director

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CONSULTING EXPERIENCE

ATLANTIC ECONOMICS LLC, Winchester, MA, 2010-present
LECG, Cambridge, MA, 1999-2010
PUTNAM, HAYES & BARTLETT, Cambridge, MA, 1994-99
McKINSEY & COMPANY, Cleveland, OH, 1993

Mr. Cadwalader applies economic analysis to assist clients who operate competitive wholesale electricity markets, or who participate in those markets. He was extensively involved in the development of the markets administered by the New York Independent System Operator. In restructuring efforts in Ontario, the PJM Interconnection, the Midwest U.S., California, and New England, he participated in the development of the energy, ancillary services, and installed capacity markets, and procedures for auctioning financial transmission rights (aka transmission congestion contracts). In the decade since those restructured markets first opened, he has participated in the further development of those markets, including the development of more sophisticated energy, ancillary services and installed capacity markets, the incorporation of new resources (such as renewable resources and demand response) into those markets, and the development of detailed procedures for monitoring and mitigating market power.

Electricity

New York

Since the markets operated by the New York Independent System Operator (NYISO) opened in late 1999, Mr. Cadwalader has advised the transmission-owning utilities in New York on the structure of those markets. With regard to New York's installed capacity market, his experience includes:

- Analyzing and developing proposals for changes to installed capacity markets to increase the likelihood that they will provide a revenue stream sufficient to induce development of adequate generating resources to meet reliability standards, while also providing proper incentives to provide installed capacity when it is most valuable and where it is most needed, including:
    - The procedures adopted by the NYISO, which call for the installed capacity requirement to vary with the price of installed capacity through use of an installed capacity "demand curve".
    - Procedures calling for forward procurement of installed capacity.

- Reviewing the analysis performed by the NYISO to set the parameters used for its installed capacity demand curves for 2005-08, 2008-11, and 2011-14, including:
    - Review of which costs and revenues are appropriately included when estimating the net cost of developing resources that are capable of providing additional installed capacity.
    - Review of procedures for converting those costs into a demand curve that will permit minimum installed capacity requirements to be met, accounting for:
        - Locational differences in the net cost of developing resources that are capable of providing additional installed capacity.
        - Costs associated with transmission expansions that would relieve locational constraints.
        - Long-run equilibrium levels of installed capacity levels that generally exceed minimum capacity requirements.
        - Seasonal differences in the amount of capacity offered into the installed capacity markets, and the resulting effect on capacity prices.
        - Forecasted increases over time in the cost of developing additional peaking generation.
        - Reasonable estimates of availability for generators using new technologies.
    - Analysis of the impact of various candidate installed capacity demand curves on costs borne by end-use consumers.
- Developing and analyzing proposals to permit the installed capacity market to recognize and deal efficiently with locational constraints that may limit the ability of generation in one region to meet load in other regions, including:
    - Analysis of the impact that defining new zones with associated installed capacity requirements to reflect locational constraints would have on the ability of the installed capacity market to support entry in transmission-constrained regions when needed.
    - Analysis of the likelihood that adding such zones would lead to spurious differences in installed capacity prices even when constraints do not limit the ability of generation in one region to meet load in other regions, and analysis of procedures for setting prices that would reduce the likelihood of such increases.
- Analyzing the potential impact of economic and physical withholding on prices realized in the installed capacity market and analyzing reports issued by the NYISO regarding the extent to which installed capacity has been withheld.

- Analyzing and recommending revisions to procedures used by the NYISO to assess whether market power has been exercised in the New York City market, and the procedures the NYISO proposes to use to assess whether market power has been exercised in any newly defined capacity zones, including:

  - Review of complaints filed by installed capacity suppliers alleging that the NYISO was not properly following its procedures, and assessment of issues raised in the complaints.

  - Development of an improved approach for calculating the maximum amount of installed capacity that may be controlled by ICAP suppliers seeking exemptions from offer caps, which is intended to ensure that suppliers with incentives to withhold capacity are not exempted from mitigation while also increasing the likelihood that suppliers without such incentives are exempted.

  - Analysis of the impact of the NYISO's assumptions regarding long-run equilibrium levels of capacity on the point on the NYISO's installed capacity demand curve that should be used to set the default offer floor applicable to entrants.

  - Analysis of the NYISO's procedures for setting default offer floors calculated when one capacity zone is nested within another, and the potential impact of these rules when they preclude entrants from selling capacity.

  - Review of proposals developed by the NYISO for determining whether entrants are exempted from offer floors when those entrants submit multiple proposals requesting capacity resource interconnection service, which are separately evaluated for the purpose of determining whether they will be exempted, and developed modifications to those proposals to ensure that expansions that the NYISO deems economic are exempted from offer floors.

- Analyzing proposals for modifying procedures for calculating the amount of collateral that must be posted by entities that may need to purchase installed capacity in the NYISO's monthly spot market auction, recommending short-term changes to those procedures, and developing longer-term revisions that would ensure that the collateral requirement is consistent with reasonable expectations of the amount that a customer might be charged for spot market auction purchases.

- Developing procedures for estimating the impact that transmission expansions would have on installed capacity costs borne by end use customers.

- Analyzing and developing proposals to modify the installed capacity markets in order to increase incentives for installed capacity providers to be available to produce energy, including analysis of the effect of these changes on locational installed capacity requirements and market mitigation rules.

- Developing modified procedures permitting installed capacity requirements to be based on customers' forecasted contributions to statewide peak load.

- Analyzing the implications of proposals to change the installed capacity market from a semiannual market to a monthly market, to modify procedures for calculating installed capacity requirements, and to change procedures for determining the amount of installed capacity that providers can offer into seasonal capacity markets.

- Analyzing and developing a proposal to enhance the ability of external suppliers to supply installed capacity into the New York markets, without inadvertently creating opportunities for some market participants to limit others' ability to offer capacity into that market.

- Developing various proposals to improve the procedures used to allocate rights to provide installed capacity in the New York market using capacity located outside New York.

- Analyzing modifications to the methods used to calculate the amount of capacity provided by market participants that would reduce the need for adjustments to installed capacity requirements to ensure that they meet reliability objectives.

- Analyzing the consequences that development of large amounts of highly temperature-sensitive generating capacity would have on installed capacity costs.

With regard to New York's energy and ancillary services markets, his experience includes:

- Reviewing proposals by the NYISO to coordinate real-time schedules with ISO-NE, pointing out problems that could limit the degree to which these proposals would meet their objective of reducing differences between the actual level of interchange between New York and New England and the efficient level of interchange, analyzing the proposal's implications for uplift payments, and developing modifications to settlement procedures.

- Reviewing the "market to market coordination" proposal developed by the NYISO and PJM (which establishes procedures for coordinating real-time dispatch when the NYISO can re-dispatch to manage congestion on a PJM constraint at lower cost than PJM can or vice versa) and the proposed settlement procedures including procedures for calculating the amount of energy that each of the participating ISOs would be permitted to flow over constraints in the other's system, and proposing changes.

- Reviewing the changes in the regulation market proposed by the NYISO to comply with Order 755 (which required ISOs to pay separately for regulation capacity and regulation performance), and developing an alternative procedure which would result in more efficient regulation procurement.

- Reviewing the changes to procedures for paying demand response providers proposed by the NYISO to comply with Order 745 (which required ISOs to pay the locational marginal price for demand reduction when doing so would cause a net reduction in payments by consumers), and assessing whether those

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procedures complied with those requirements when there is transmission congestion.

- Analyzing the impact that phase angle regulators on the Ontario-Michigan border would have on costs incurred by participants in the NYISO market.

- Assessing procedures intended to ensure that generators that seek to retire, but cannot be permitted to do so for reliability reasons, are neither disadvantaged nor advantaged as a result of not being permitted to retire.

- Reviewing the impact of plans to remove restrictions that had forbidden generators receiving schedules in the day-ahead market from submitting real-time offers at prices that exceeded their day-ahead offers.

- Evaluating the procedures the NYISO uses to calculate guarantee payments made to market participants to ensure that financial settlements for each market participant are consistent with the bids submitted by that participant, and to eliminate opportunities to game those payments by scheduling some energy for sale through bilateral transactions while other energy is sold directly into the market.

- Reviewing and proposing changes in procedures proposed by the NYISO to account for deviations between actual output and instructed output for some resources when determining real-time energy prices.

- Analyzing proposals that would permit market participants without generating or load-serving capability to submit bids to produce or consume energy in the day-ahead market, while ensuring that physical generating capacity would be started when necessary to ensure reliable service, and limiting the degree to which participants in these transactions would shift costs onto other market participants.

- Reviewing proposals to permit operating reserve and regulation shortages, the need to rely upon recallable exports and the need to resort to emergency demand reduction programs to be reflected in energy prices, and to revise the methods used to calculate energy and ancillary services prices in the NYISO's real-time markets to permit implementation of a full two-settlement system for energy and all dispatch-based ancillary services.

- Reviewing the NYISO's calculations of the amounts to be paid or collected from various market participants in the real-time market during scarcity conditions, and ensuring the consistency of those prices with the rules governing the calculation of prices during such conditions.

- Analyzing and developing proposals for mechanisms to mitigate market power in the NYISO's day-ahead and real-time energy markets, and reviewing others' proposals.

- Developing proposals that would permit effective mitigation of generator's start-up cost bids in cases where the generator had changed its minimum output level, in a manner that accounts for changes in fuel costs over time.

- Reviewing the market monitoring unit's assessment of the competitiveness of the energy market.

- Analyzing a procedure the NYISO proposed to use to compensate generators that were erroneously committed due to the use of a flawed test assessing whether market power was being exercised, and illustrating the problems with that procedure.

- Analyzing the consequences of errors in the NYISO's day-ahead commitment procedures on day-ahead and real-time prices.

- Analyzing and developing proposals to modify settlement procedures for import and export transactions to eliminate gaming opportunities.

- Analyzing proposals to modify procedures used to calculate the amount that market participants are paid for providing voltage support payments, and developing a procedure that improves incentives for developing this capability.

- Analyzing the methods used by the NYISO to calculate prices when fixed-block units are dispatched.

- Developing a proposal to modify procedures for calculating locational operating reserve requirements, thereby permitting those requirements to be reduced when congestion costs in the energy market are relatively low.

- Developing a proposal to modify procedures for calculating the amount of energy that can be imported from Quebec, thereby permitting additional energy to be imported when the cost of procuring additional operating reserve is relatively low.

- Refuting testimony filed by a market participant opposing the use of marginal loss pricing in New York.

With regard to markets for financial transmission rights (called transmission congestion contracts (TCCs) in New York), his experience includes:

- Analyzing the outcomes of NYISO-administered auctions of TCCs, and developing recommendations regarding the release of TCCs in later auctions.

- Analyzing mechanisms to modify procedures used to conduct these auctions so that market participants have additional flexibility with respect to choosing the time period for which they purchase TCCs, and the auction rounds in which they wish to sell TCCs.

- Developing proposals for awarding TCCs to developers of merchant transmission expansions, which would grant those developers additional autonomy to determine the type of awards they would receive.

- Developing proposals for forecasting the net impact, including the impact on energy costs and revenues from TCCs, of regulated transmission expansions on customers in different parts of the state, for the purpose of allocating costs of

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those expansions among prospective beneficiaries in a manner that reflects differences in the net benefits that beneficiaries in different areas are expected to receive.

- Developing mechanisms for allocating revenues from the sale of TCCs among transmission owners, and for modifying those mechanisms to account for the issuance of long-term fixed-price TCCs.

- Reviewing proposals to allocate the costs associated with transmission outages to the entities responsible, thereby giving them market-based incentives to minimize the costs associated with these outages, and reducing the frequency with which the revenues collected by the NYISO as a result of transmission congestion are insufficient to fund the NYISO's obligations to purchasers of TCCs.

- Reviewing proposals to resolve chronic revenue shortfalls resulting from the sale of more TCCs than can be supported by congestion revenues collected by the NYISO through the use of locational pricing for energy in the day-ahead market.

- Analyzing proposed changes to the procedures used by the NYISO for modeling the impact of transmission losses on the number of TCCs that can be sold in any given round of the TCC auction and the potential consequences of those changes for these congestion revenue shortfalls.

His background pertaining to the New York market also includes:

- Critiquing a report that calculated the damages incurred by various owners of generation in New York as a consequence of a finding by the Federal Energy Regulatory Commission that the NYISO's method for translating installed capacity requirements into unforced capacity requirements violated the NYISO's tariff.

- Analyzing restrictions imposed by the New York Independent System Operator on the amount of installed capacity that a load-serving entity on Long Island was permitted to self-supply, and of the impact on costs incurred by that LSE if those restrictions had not been imposed.

- Analyzing the consequences of errors committed by the NYISO when conducting TCC auctions, evaluating the NYISO's proposals to correct those errors, reviewing the calculations performed by the NYISO to implement those corrections, and documenting those calculations.

- Evaluating a generator's request for permission to build at a site in New York, focusing on the costs that development at this site would impose upon other market participants due to that generator's impact on transmission constraints given the way that the NYISO's installed capacity and ancillary services markets handled such constraints.

- Assessing various options for ensuring that a utility receives the transmission service to which it is entitled in an ISO-administered market under contracts that predate the development of ISOs.

- Evaluating the technical impediments to developing a single market for a Regional Transmission Organization that was proposed for the Northeast U.S.
- Analyzing proposals for allocating the costs associated with reliability-mandated upgrades, and developing mechanisms for allocating those costs;
- Reviewing the implications of FERC orders pertaining to the New York market and elsewhere, and assessing their likely implications for the New York markets.
- Reviewing numerous tariff changes and other filings made by the NYISO, to ensure they are consistent with their stated purposes.

Mr. Cadwalader's earlier involvement in the creation of the markets operated by the NYISO included developing procedures for:

- Auctioning TCCs.
- Creating competitive markets for the provision of ancillary services.
- Creating competitive markets for the supply of installed capacity, including drafting the rules for, descriptions of, and tariff language governing auctions of installed capacity, and developing the models to be used in those auctions.
- Giving ancillary service providers incentives to provide the services they have been selected to provide, without being excessively punitive.
- Scheduling generating units on a day-ahead basis so that loads that have purchased energy in the day-ahead market can be served as efficiently as possible, while not jeopardizing the system's ability to serve all loads.
- Ensuring that generators dispatched by the NYISO will have incentives to follow their instructions.
- Pricing transactions in which energy is injected or withdrawn in external control areas.
- Permitting market participants to schedule bilateral transactions that do not impose physical obligations to perform on any particular generator.
- Allocating TCCs to market participants with pre-existing transmission rights.
- Allocating responsibility for the fixed costs of the transmission system while retaining incentives that encourage efficiency.
- Calculating guarantee payments that ensure that all market participants recover their full bids for all services they provide (or, in the day-ahead market, are scheduled to provide).

In addition, Mr. Cadwalader's other work in developing the New York market included:

- Illustrating how multi-settlement systems for electricity pricing can permit electricity to be generated at lower cost than one-settlement systems, can deter gaming by market participants, and can bring about price certainty for a broad range of market participants.

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- Developing models illustrating how basing electricity prices on location-specific marginal costs induces efficiency in the dispatch of existing generation, the construction and siting of new generation, and the construction of additional transmission capacity, and comparing these effects to the consequences of other pricing systems that provide different incentives.

- Illustrating ways in which participants in electricity systems using location-specific marginal cost pricing can write contracts enabling sellers and buyers of power to hedge against risks, but which do not impede incentives for economic efficiency in generation markets.

- Developing detailed explanations of the procedures used to determine advance schedules for generators and loads, to dispatch generators in real time, and to calculate locational electricity prices.

- Preparing comparisons of the transmission costs that market participants would bear under locational pricing to the costs they bore under tariffs in effect at that time.

- Explaining details of the restructuring proposal to regulators and to other market participants.

- Drafting portions of the NYISO's tariffs, and developing responses to filings by intervenors in proceedings at FERC.

Ontario

In Ontario, Mr. Cadwalader assisted the Independent Electricity System Operator (IESO) in its review of procedures used by the IESO's Market Assessment Unit to identify anomalous market participant behavior and flaws in the design of the IESO-administered electricity markets. Mr. Cadwalader co-authored a report recommending certain changes to these procedures.

Mr. Cadwalader also assisted the Independent Electricity System Operator (IESO) in the development of several aspects of its Market Evolution Program, including:

- Assessing opportunities to develop a day-ahead market, in which the IESO would schedule generators to meet anticipated load during the next day using offers and bids submitted for the next day, permitting a more efficient commitment of resources, enhancing the ability of some market participants to participate in the market by providing the opportunity to lock in costs or revenues a day in advance, and reducing the likelihood that insufficient resources will be available the next day to serve load reliably.

- Developing procedures for conducting an enhanced day-ahead commitment procedure, in which resources would be scheduled based on day-ahead offers and guarantee payments for committed resources would be based upon those offers, when it became apparent that a complete day-ahead market could not be implemented due to the absence of locational pricing in Ontario.

- Developing the structure of a "resource adequacy" market, which would compensate generation or demand response resources that make their capacity available to serve load within Ontario, thereby ensuring that sufficient capacity to meet reliability requirements is developed (or remains in service).

Mr. Cadwalader's previous involvement in the design of the Ontario market (some of which was performed for the IESO, and some of which was performed for the Ontario Market Design Committee, which developed the blueprint for the electricity market that the IESO now operates), included:

- Developing modifications to settlement procedures for import and export transactions in order to provide increased price certainty for participants in those transactions and to eliminate gaming opportunities.
- Assessing the need for an installed capacity market and recommending how such a market ought to be implemented, if such a need existed.
- Assessing the procedures the IESO would use to calculate prices during shortages and to determine bid and price caps.
- Developing the structure of the market for financial transmission rights, including:
    - Creating a procedure for defining financial transmission rights that permits these instruments to be defined as financial options.
    - Detailing procedures for the IESO to use to determine how many financial transmission rights it can issue without incurring undue financial risk.
    - Developing procedures for conducting auctions of these financial transmission rights.
- Developing proposals for competitive and efficient markets for regulation and operating reserves.
- Analyzing proposals for non-locational pricing and illustrating the difficulties that follow from such procedures.
- Proposing mechanisms for compensating generators that have been dispatched to operate and for compensating generators that have not been dispatched to operate that would give these generators incentives to follow dispatch instructions.

Midwest ISO

In the markets administered by the Midwest ISO, Mr. Cadwalader has been involved in:

- Developing the enhanced LMP approach for calculating energy and ancillary services prices, which (in addition to the cost of incremental output) incorporates start-up and minimum generation costs in electricity prices.
- Developing the structure for procuring energy, operating reserve and regulation and pricing those services that the MISO used when it expanded its energy markets to encompass operating reserve and regulation, testifying regarding these changes, and conducting a detailed evaluation of the MISO's plans for implementing those markets.

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- Evaluating and critiquing proposals by advocates of "flowgate" transmission rights, which were rights to flow energy over individual transmission facilities, as opposed to rights to payments that would hedge congestion charges incurred when injecting energy at one location and withdrawing it at another.

- Developing the outlines of procedures that different control areas participating in the Midwest ISO could have used to coordinate congestion management among themselves.

- Reviewing proposals for the allocation of financial transmission rights among market participants.

PJM

Mr. Cadwalader's work involving the markets administered by PJM has included:

- Evaluating the initial proposal for the Basic Generation Service auction in New Jersey, in which all of the utilities in a state simultaneously purchase their energy and ancillary services requirements from suppliers, using a simultaneous descending clock auction (similar to the mechanism used in telecommunications spectrum auctions).

- Evaluating the likely consequences for consumers of proposals to modify the Basic Generation Service auction to mandate long-term purchases from new generating facilities in New Jersey.

- Analyzing the likely consequences of a proposal for the state of Maryland to "re-regulate" electricity markets there.

- Estimating the cost of purchasing the portion of the generation fleet in PJM that was not already owned by the municipally-owned utilities or the regulated portions of investor-owned utilities, and illustrating how transferring ownership of generators to regulated entities would not reduce electricity charges for customers in the long run.

- Evaluating the procedures that PJM uses to recoup operating reserve charges from market participants, their relationship to cost causation, and their implications for market efficiency.

- Developing procedures that PJM and neighboring control areas could use in order to improve coordination of real-time congestion management among different control area operators.

- Developing a two-settlement system, including a day-ahead settlement for generators, LSEs and transmission customers.

- Drawing up procedures for auctioning FTRs.

- Creating a competitive market for the provision of regulation services.

California

Work that Mr. Cadwalader performed regarding the California markets included:

- Analyzing the ability for a generator owner to predict whether a generator it owned would be "dec'd" (i.e., it would not be able to produce electricity due to transmission congestion), and analyzing the impact that scheduling that generator to produce less energy would have had on that generator owner and on the entity buying energy under an energy purchase agreement with that generator owner.

- Analyzing whether a generator owner's decision to purchase energy to fulfill its obligations under an energy purchase agreement, instead of building a simple-cycle generator to provide that energy, was reasonable given changes in market fundamentals after the contract was entered into, and analyzing the consequences of not having constructed that generator on the purchaser of energy under that agreement.

- Reviewing the California ISO's proposed market re-design to base its market on locational marginal pricing, and preparing a paper critiquing the proposal.

- Summarizing the multi-settlement procedure and market mitigation mechanisms in place in the Northeast for the benefit of market participants.

- Preparing a summary of fundamental principles and procedures that should be used to define congestion revenue rights, and evaluating proposals under consideration in California ISO working groups with those principles in mind.

Before the California ISO adopted its initial market design, Mr. Cadwalader assisted in the development of numerous presentations and filings illustrating the advantages of power markets such as those that were adopted in the Northeast.

Other Experience

In New England, Mr. Cadwalader assisted in the development of proposals for the allocation of auction revenue rights, which are used to allocate revenues from the sale of financial transmission rights.

In the Southwest Power Pool, Mr. Cadwalader developed proposals for a market for installed capacity, building upon the lessons learned in the installed capacity markets in the Northeastern U.S., and evaluated and critiqued proposals for real-time and forward energy markets, including proposals to offer both "flowgate" transmission rights and point-to-point financial transmission rights simultaneously.

In the Northwestern U.S., Mr. Cadwalader developed and presented parts of a two-day seminar for market participants discussing various options for electricity market design.

Mr. Cadwalader's other experience relating to electricity markets includes:

- Analyzing a proposal by the Federal Energy Regulatory Commission to pay locational marginal prices to all demand response providers who reduce their consumption, and the implications for economic efficiency of such a proposal.

- Reviewing the bids submitted into an auction of financial transmission rights to assess whether the outcome was consistent with competitive market behavior.

- Estimating the financial consequences for a utility if the purchaser of transmission service under a long-term contract with that utility exercised its option to terminate that contract.

- Estimating the effect of the loss of liquidity in electricity markets on the value of positions held by an energy marketer.

- Developing the framework for an installed capacity procurement strategy that struck an optimal balance between minimizing costs and assuming risks.

- Assisting a utility in assessing the extent to which it could reduce its costs by developing additional generation in its service area.

- Creating pricing formulas for an electricity retailer that would permit it to identify the costs incurred to serve various customers, so that it could permit customers to choose from a wide variety of hedging options while minimizing its own exposure to risk.

- Coordinating a large study of stranded costs and developing models for use in the study. Data on fixed and variable costs for individual generators, together with output from a sophisticated electricity dispatch model, were used in models developed for this study to predict the amount and type of generation capacity that would remain in service under a variety of scenarios regarding the future structure of electricity markets. Stranded cost estimates incorporated the effects of changes in demand resulting from changes in price, economy energy imports available from external sources, and potential entrants into a generation market in which no generators receive subsidies.

- Predicting the impact of market power on prices in a deregulated generation market. These studies used a competitive bidding model developed especially for this purpose. The results demonstrated the effects of various degrees of market power on market prices and illustrated the situations in which significant distortions in pricing due to market power are most likely.

- Developing a program to revamp capital budgeting procedures used by an electric utility client, increasing the cost-effectiveness of these expenditures while also providing additional assurance that capital spending was consistent with the client's strategic objectives.

Aluminum

Mr. Cadwalader assisted an aluminum company in analyzing the proportion of the cost of a bauxite mining and alumina refining operation that represented the value of the land and mining rights associated with the operation, which was pertinent to the determination of whether the purchase price was subject to an *ad valorem* tax.

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EDUCATION

MBA, with distinction, Finance and Strategic Management, WHARTON SCHOOL, UNIVERSITY OF PENNSYLVANIA, Philadelphia, PA, May 1994

- Named a Palmer Scholar (top five percent of graduating class).

MA, Economics, UNIVERSITY OF ROCHESTER, Rochester, NY, October 1988

- Passed Ph.D. qualifying examination.
- W. Allen Wallis Fellow.
- Herbert H. Lehman Scholar.

AB, *summa cum laude,* Mathematics and Economics, WASHINGTON UNIVERSITY, St. Louis, MO, May 1985

- Elected to Phi Beta Kappa.
- Arthur Holly Compton Fellow.
- National Merit Scholar.

OTHER POSITIONS HELD

INLAND STEEL INDUSTRIES, Chicago, IL, Business Plan Analyst, 1991–92

Mr. Cadwalader prepared forecasts of income statements, balance sheets and cash flow statements for the firm and various subsidiaries.

INLAND STEEL INDUSTRIES, Chicago, IL, Internal Auditor, 1988–91

Mr. Cadwalader conducted reviews of various aspects of the company's operations. Representative projects included:

- Reviewing the procedures used to select capital projects and to monitor their progress.
- Analyzing the procedures used to verify freight discounts granted to customers.
- Assessing the weaknesses of a procedure that tracked liquid nitrogen and oxygen costs, and implementing improvements to correct these deficiencies.

UNIVERSITY OF ROCHESTER, Rochester, NY, Instructor, 1987

Mr. Cadwalader taught one half-semester of Advanced Macroeconomics and served as a teaching assistant for courses in intermediate microeconomics and risk and insurance.

LAURENCE H. MEYER & ASSOCIATES (now Macroeconomic Advisers), St. Louis, MO, Research Assistant, 1984

Mr. Cadwalader assisted in the development of models used to prepare macroeconomic forecasts.

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CONFERENCES AND OTHER SELECTED PRESENTATIONS

1. "Forecasting the Market Price of Electricity for Stranded Investment Calculations" (with Susan Pope and Rana Mukerji), June 19, 1996, IBC Conference on Strategies to Measure, Mitigate and Recover Stranded Costs, Washington, DC.
2. "Understanding Transmission" (with Scott Harvey), Mar. 31, 1998, Pasha Publications ERCOT Power Markets Conference, Houston, TX.
3. "Buying and Selling Power through the PJM Energy Market" (with Susan Pope), June 9, 1998, Infocast Conference on Taking Advantage of Electricity Choice in Pennsylvania & New Jersey, Philadelphia, PA.
4. "How LMP Works" (with John Chandley), June 16, 1998, Pasha Publications Conference on Locational Marginal Pricing: Using PJM for Risk Management, Philadelphia, PA.
5. "Market-Based Pricing of Ancillary Services under the New York ISO," Oct. 15, 1998, EUCI Ancillary Services Conference, Denver, CO.
6. "Understanding Transmission" (with Scott Harvey), Oct. 26, 1998, PowerMart '98, Houston, TX.
7. "Efficient Competitive Markets for Ancillary Services", Mar. 4, 1999, EUCI Ancillary Services Conference, Denver, CO.
8. "How Transmission Works: Paths, Costs, Rights and ISOs" (with Joe Graves and Steve Henderson), Mar. 23, 1999, FT Energy Conference on Transmission Issues: Access, Reliability and Markets, Houston, TX.
9. "A Status Report on the Development of Competitive Ancillary Services Markets," Mar. 25, 1999, Infocast Conference on New Business Opportunities in Competitive Ancillary Services Markets, Philadelphia, PA.
10. "How Transmission Works: Paths, Costs, Rights and ISOs" (with Joe Graves and Steve Henderson), June 8, 1999, FT Energy Conference on ECAR Power Markets: Plugging into the Powerful Midwest, Columbus, OH.
11. "Further Exploration of Transmission Rights Issues," IMO Technical Panel, July 27, 1999, Toronto, ON.
12. "Criteria for Assessing How Payments to Holders of Transmission Rights Should Be Determined," IMO Technical Panel, Aug. 10, 1999, Toronto, ON.
13. "Key Features of the Strawman Proposal for Transmission Rights," IMO Technical Panel, Aug. 31, 1999, Toronto, ON.
14. "Options vs. Obligations: The Experience of Other Markets," IMO Technical Panel, Sept. 14, 1999, Toronto, ON.

15. "How Transmission Works: Paths, Costs, Rights and ISOs" (with Joe Graves, Steve Henderson and Abram Klein), Sept. 28, 1999, FT Energy Conference on PJM Power Markets: Making Adjustments, Philadelphia, PA.

16. "Managing Transmission Price Risk with Financial Transmission Rights," Oct. 1, 1999, Infocast Merchant Plant Development and Finance Conference, Houston, TX.

17. "Activity Rules for the Transmission Rights Auction," IMO Technical Panel, Oct. 12, 1999, Toronto, ON.

18. "Applying Congestion Pricing to Markets for Ancillary Services" and "Using Financial Transmission Rights to Hedge Against Transmission Costs," Nov. 19, 1999, Infocast Conference on Congestion Pricing and Forecasting, Washington, DC.

19. "Awarding TCCs to Investors in Transmission Expansions," Dec. 17, 1999, NYISO Market Structures Working Group, Albany, NY.

20. "Congestion Management Workshop" (with John Chandley and Susan Pope), June 6–7, 2000, RTO West Congestion Management Working Group, Portland, OR.

21. "Ancillary Services Workshop," June 8, 2000, RTO West Congestion Management Working Group, Portland, OR.

22. "Implementing Flowgate Rights in an LMP System" and "Coordination of Congestion Management," July 19, 2000, Joint Industrial Summit and MISO Advisory Committee Meeting, Rosemont, IL.

23. "Coordinating Congestion Management Across Multiple Control Areas", MISO Committees, Sept. 14, 2000, Indianapolis, IN.

24. "Transmission Access and Risk," Oct. 3, 2000, Infocast Conference on Portfolio Risk Analysis and Management, Chicago, IL.

25. "Flowgate Rights: Can They Deliver?," Feb. 8, 2001, EUCI Congestion Management Conference, Denver, CO.

26. "How Optimal is Optimal? A Comparison of Procedures Used to Optimize Ancillary Services Markets" and "Market-Based Pricing of Ancillary Services: Market Design Choices, Consequences and Outcomes" (with Matthew Kunkle), Nov. 1–2, 2001, EUCI Ancillary Services Conference, Denver, CO.

27. "Implementing Installed Capacity Markets: Why You Shouldn't Fire Before You Aim," Mar. 25, 2002, EUCI Electricity Market Design Conference, Atlanta, GA.

28. "Lessons from the Installed Capacity Markets in the Northeast," Apr. 1, 2002, ERCOT Generation Adequacy Working Group, Austin, TX.

29. "Northeastern Electricity Markets: Day-ahead and Real-time Markets in New York and PJM, and New York's AMP," May 17, 2002, IEP/CMUA Market Design Seminar, Sacramento, CA.

30. "Imports, Exports and FTR Settlement in the Day-Ahead Market," June 19, 2003, IMO Day-Ahead Markets Working Group, Mississauga, ON.

31. "Timing of the Price Calculation in the Day-Ahead Market," June 25, 2003, IMO Day-Ahead Markets Working Group, Mississauga, ON.

32. "Optimally Designing Resource Adequacy Requirements," June 26, 2003, IMO Long-Term Resource Adequacy Working Group, Mississauga, ON.

33. "Is There a Workable Market Solution for Assuring Resource Adequacy? The Case of Decreasing Incremental Cost Curves" and "Implementation of Resource Adequacy Requirements in the Northeast U.S.," July 9, 2003, IMO Long-Term Resource Adequacy Working Group, Toronto, ON.

34. "Auctioning the Responsibility to Serve Load: A Potential Solution for the 'Buyer Issue,'" July 24, 2003, IMO Long-Term Resource Adequacy Working Group, Mississauga, ON.

35. "Centralized Procurement of Resources to Meet a Resource Adequacy Requirement," Aug. 6, 2003, IMO Long-Term Resource Adequacy Working Group, Toronto, ON.

36. "The NYISO Installed Capacity Demand Curve," Aug. 20, 2003, IMO Long-Term Resource Adequacy Working Group, Toronto, ON.

37. "Shaping Price Caps for In-City Installed Capacity," Aug. 25, 2003, NYISO Installed Capacity Working Group, Albany, NY.

38. "Marginal Loss Pricing and Financial Transmission Rights," Sept. 16, 2003, IMO Day-Ahead Markets Working Group and Long-Term Resource Adequacy Working Group, Mississauga, ON.

39. "Market Power Mitigation in the Day-Ahead Market," Sept. 29, 2003, IMO Day-Ahead Markets Working Group, Mississauga, ON.

40. "Transitional Issues Associated with Resource Adequacy," Oct. 15, 2003, IMO Long-Term Resource Adequacy Working Group, Toronto, ON.

41. "FTR Issues: Allocation, Pricing and Payments," Oct. 20, 2003, IMO Day-Ahead Markets Working Group, Mississauga, ON.

42. "Inducing Near-Term Development of Generating Capacity," Nov. 12, 2003, IMO Long-Term Resource Adequacy Working Group, Mississauga, ON.

43. "Defining the Resource Adequacy Product," Jan. 13, 2004, IMO Long-Term Resource Adequacy Working Group, Toronto, ON.

44. "Defining the Resource Adequacy Product: Follow-Up," Feb. 11, 2004, IMO Long-Term Resource Adequacy Working Group, Mississauga, ON.

45. "Determination of the Resource Adequacy Requirement," Feb. 25, 2004, IMO Long-Term Resource Adequacy Working Group, Toronto, ON.

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46. "The Planning Horizon and the Commitment Period," Mar. 10, 2004, IMO Long-Term Resource Adequacy Working Group, Toronto, ON.

47. "Structure of Auctions Used in the Resource Adequacy Market," Mar. 24, 2004, IMO Long-Term Resource Adequacy Working Group, Mississauga, ON.

48. "Using Demand Curves to Determine Resource Adequacy Requirements," Apr. 7, 2004, IMO Long-Term Resource Adequacy Working Group, Toronto, ON.

49. "Meeting Operating Reserve Requirements at the Lowest Cost," May 10, 2004, NYISO Scheduling & Pricing Working Group, Albany, NY.

50. "Interregional Trade in Installed Capacity," "Determining the Commitment Period for ICAP Suppliers", and "Designing and Implementing Installed Capacity Markets," May 21, 2004, EUCI Installed Capacity Conference, Boston, MA.

51. "Regional Flexibility in Resource Adequacy Requirements" and "Resource Adequacy Requirements and Market Power," Dec. 2, 2004, EUCI Resource Adequacy Conference, San Francisco, CA.

52. "Are Resource Adequacy Requirements Needed to Meet Reliability Objectives" and "Resource Adequacy Requirements and Market Power," Apr. 14, 2005, EUCI Resource Adequacy Conference, Washington, DC.

53. "Energy and Operating Reserves Markets That Provide Incentives for Efficient Operation, Commitment and Development," Mar. 16, 2006, MISO Ancillary Services Task Force, Carmel, IN.

54. "Efficient Procurement and Pricing of Operating Reserves in Markets with Multiple Operating Reserve Requirements, Multiple Locations and Multiple Settlements," Apr. 11, 2006, MISO Ancillary Services Task Force, Carmel, IN.

55. "Alternatives to Purchasing Operating Reserves in a Simultaneously Optimized Day-Ahead Market" and "Incentives for Self-Supply and Interrelationships Between Energy and Operating Reserves Prices in Simultaneously Optimized Markets," May 9, 2006, MISO Ancillary Services Task Force, Carmel, IN.

56. "Simultaneously Optimized Markets for Energy, Operating Reserves and Regulation," June 28, 2006, MISO Ancillary Services Task Force, Carmel, IN.

57. "Market Monitoring and Mitigation Procedures in the Installed Capacity Market," July 6, 2006, NYISO Installed Capacity Working Group, Albany, NY.

58. "Cost Recovery in a Competitive Installed Capacity Market," Aug. 1, 2006, NYISO Installed Capacity Working Group, Albany, NY.

59. "Adjusting Installed Capacity Demand Curves to Account for Seasonal Variations in Installed Capacity Prices," May 2, 2007, NYISO Installed Capacity Working Group, Albany, NY.

60. "24-Hour Optimization in Day-Ahead Markets," Oct. 30, 2007, IESO Stakeholder Information Session, Toronto, ON.

61. "Comparing Methods for Calculating Production Cost Guarantee Payments that Focus on Day-Ahead Constrained Schedules," Nov. 30, 2007, IESO Production Cost Guarantee Technical Support Group, Toronto, ON.

62. "Disadvantages of Methods for Calculating Production Cost Guarantees that Focus on Day-Ahead Unconstrained Schedules," Jan. 30, 2008, IESO Production Cost Guarantee Technical Support Group, Toronto, ON.

63. "Another Method for Calculating Production Cost Guarantee Payments," IESO Production Cost Guarantee Technical Support Group, Jan. 30, 2008, IESO Production Cost Guarantee Technical Support Group, Mississauga, ON.

64. "Market Rules That Apply When an LSE Acquires More Unforced Capacity Than It Needs to Meet Its Share of a Locational UCAP Requirement," June 17, 2008, NYISO Installed Capacity Working Group, Rensselaer, NY.

65. "Production Cost Guarantee and Congestion Management Settlement Credit Calculation in an Enhanced Day-Ahead Commitment Procedure," July 15, 2008, IESO Day-Ahead Guarantees and Export Inclusion Technical Support Group, Mississauga, ON.

66. "Additional Details of Production Cost Guarantee Calculation in an Enhanced Day-Ahead Commitment Procedure," Sept. 4, 2008, IESO Day-Ahead Guarantees and Export Inclusion Technical Support Group, Mississauga, ON.

67. "Incorporating Operating Reserves in the Day-Ahead Production Cost Guarantee Calculation," Jan. 21, 2009, IESO Enhanced Day-Ahead Commitment Technical Support Group, Mississauga, ON.

68. "Incorporating the Impact of a Project on Congestion Rents When Calculating the Net Benefit Realized by Load in Each Zone," May 28, 2009, NYISO Electric System Planning Working Group, Rensselaer, NY.

69. "Description of the Procedure for Forecasting the Impact of a Project on TCC Revenues Allocated to Load in Each Zone," Feb. 23, 2010, NYISO Electric System Planning Working Group, Rensselaer, NY.

70. "Bidding Requirements for ICAP Spot Market Auctions," Oct. 10, 2012, NYISO Credit Policy Working Group, Rensselaer, NY.

TESTIMONY

Before the Federal Energy Regulatory Commission, Affidavit Submitted on Behalf of the Member Systems of the New York Power Pool Regarding the General Structure of the New York Installed Capacity Market, Docket Nos. ER97-1523-000, OA97-470-000, and ER97-4234-000 (not consolidated), May 28, 1999.

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Before the Federal Energy Regulatory Commission, Review of the California ISO's MD02 Proposal (joint affidavit with Scott Harvey and William Hogan), Docket Nos. EL00-95-001 and ER02-1656-000, June 4, 2002.

Before the Federal Energy Regulatory Commission, Affidavit Submitted on Behalf of the New York Transmission Owners Regarding the Cost of Losses Associated with Transmitting Energy Under a Grandfathered Transmission Contract, Docket Nos. OA97-470-065, ER97-1523-070, and ER97-4234-063 (not consolidated), Oct. 16, 2002.

Before the Federal Energy Regulatory Commission, Initial Remand Testimony Submitted on Behalf of the Consolidated Edison Company of New York, Inc., Regarding the Allocation of Transmission Congestion Contracts to Customers Receiving Transmission Service Under Grandfathered Contracts, Docket No. EL02-23-000, Jan. 29, 2003.

Before the Federal Energy Regulatory Commission, Rebuttal Remand Testimony Submitted on Behalf of the Consolidated Edison Company of New York, Inc., Regarding the Allocation of Transmission Congestion Contracts to Customers Receiving Transmission Service Under Grandfathered Contracts, Docket No. EL02-23-000, Feb. 19, 2003.

Before the Federal Energy Regulatory Commission, Affidavit Submitted on Behalf of the Indicated Transmission Owners, Multiple Intervenors and Municipal Electric Utilities Association of New York, Regarding Adjustments to the New York ISO's Installed Capacity Demand Curve Needed to Reflect Seasonal Price Differences in the New York Installed Capacity Market, Docket No. ER05-428-000, Apr. 5, 2005.

Before the Federal Energy Regulatory Commission, Affidavit Submitted on Behalf of the Long Island Power Authority and LIPA Regarding the Use of Capacity in Long Island to Meet LIPA's Locational Capacity Requirements, Docket No. EL07-16-000, Nov. 16, 2006.

Before the Federal Energy Regulatory Commission, Reply Affidavit Submitted on Behalf of the Long Island Power Authority and LIPA Regarding the Use of Capacity in Long Island to Meet LIPA's Locational Capacity Requirements, Docket No. EL07-16-000, Jan. 31, 2007.

Before the Federal Energy Regulatory Commission, Affidavit Submitted on Behalf of the Midwest Independent Transmission System Operator, Inc., Regarding Simultaneously Optimized Markets for Energy and Ancillary Services, Docket No. ER07-550-000, Feb. 12, 2007.

Before the Federal Energy Regulatory Commission, Affidavit Submitted on Behalf of the New York Transmission Owners Regarding the New York ISO's Proposed Installed Capacity Demand Curves for the 2008-11 Capability Years, Docket No. ER08-283-000, Dec. 24, 2007.

Before the Federal Energy Regulatory Commission, Affidavit Submitted on Behalf of the New York Transmission Owners Regarding the New York ISO's Proposed Installed Capacity Demand Curves for the 2008-11 Capability Years, Docket No. ER08-283-000, Jan. 15, 2008.

Before the Federal Energy Regulatory Commission, Answering Testimony Submitted on Behalf of the New York Transmission Owners Regarding the Calculation of Damages Incurred as a Result of Errors in Procedures Used to Determine Unforced Capacity Requirements, Docket No. EL05-17-003, Dec. 5, 2008.

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Before the Federal Energy Regulatory Commission, Affidavit Submitted on Behalf of the New York Transmission Owners Regarding the Implications of Surplus Capacity Assumptions on Installed Capacity Revenues Required to Induce the Development of Generation in New York City, Docket Nos. EL07-39-006 and ER08-695-004, July 6, 2010.

Before the Federal Energy Regulatory Commission, Affidavit Submitted on Behalf of the New York Transmission Owners Regarding the New York ISO's Proposed Installed Capacity Demand Curves for the 2011-14 Capability Years, Docket No. ER11-2224-000, Dec. 21, 2010.

Before the Federal Energy Regulatory Commission, Affidavit Submitted on Behalf of the Indicated New York Transmission Owners Regarding Criteria for the Creation of New Installed Capacity Zones in New York, Docket No. ER04-449-023, Feb. 10, 2011.

Before the Federal Energy Regulatory Commission, Supplemental Affidavit Submitted on Behalf of the Indicated New York Transmission Owners Regarding the New York ISO's Proposed Installed Capacity Demand Curves for the 2011-14 Capability Years, Docket No. ER11-2224-001, Feb. 28, 2011.

Before the Federal Energy Regulatory Commission, Supplemental Affidavit Submitted on Behalf of the Indicated New York Transmission Owners Regarding Criteria for the Creation of New Installed Capacity Zones in New York, Docket No. ER04-449-023, Mar. 8, 2011.

Before the Federal Energy Regulatory Commission, Second Supplemental Affidavit Submitted on Behalf of the New York Transmission Owners Regarding the New York ISO's Proposed Installed Capacity Demand Curves for the 2011-14 Capability Years, Docket No. ER11-2224-004, May 4, 2011.

Before the Federal Energy Regulatory Commission, Affidavit Submitted on Behalf of Consolidated Edison Company of New York, Inc., Orange and Rockland Utilities, Long Island Power Authority, New York Power Authority, the City of New York and the New York Association of Public Power Regarding the New York ISO's Procedures for Mitigating Offers Submitted by Entrants into the New York City Installed Capacity Market, Docket No. EL11-42-000, July 6, 2011.

Before the Federal Energy Regulatory Commission, Affidavit Submitted on Behalf of the New York Transmission Owners Regarding the New York ISO's Proposed Installed Capacity Demand Curves for the 2011-14 Capability Years, Docket No. ER11-2224-009, July 11, 2011.

Before the Federal Energy Regulatory Commission, Affidavit Submitted on Behalf of the New York Transmission Owners Regarding the New York ISO's Proposed Procedures for Mitigating Offers to Provide Installed Capacity Submitted by Resources in New Capacity Zones, Docket No. ER12-360-001, July 20, 2012.

Before the Federal Energy Regulatory Commission, Affidavit Submitted on Behalf of the New York Transmission Owners Regarding the New York ISO's Proposed Procedures for Calculating Real-Time Prices for Operating Reserves and Regulation During Localized Scarcity Conditions, Docket No. ER13-909-000, April 4, 2013.

Exhibit 8

REDACTED DOCUMENT

Exhibit 8
Jobs Impacts Summary

Summary of REMI Model Economic Impact Results

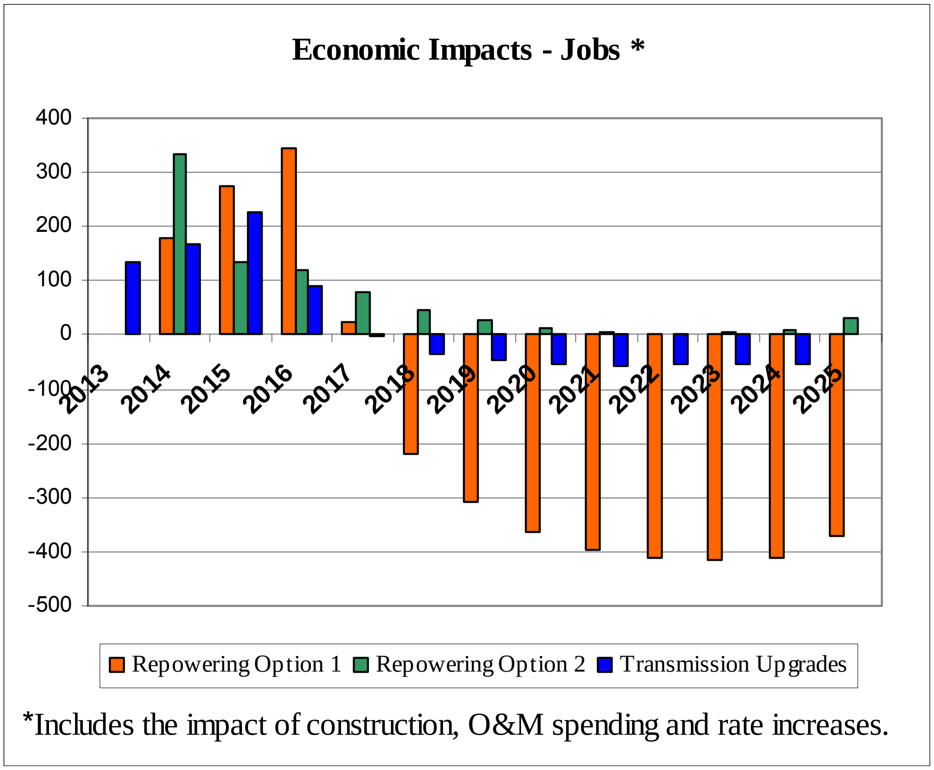
	Repowering Option 1	**Repowering Option 2**	**Transmission Upgrades**
State of New York			
Avg. Jobs During Construction, 2014-2017	248	132	156
Avg. Jobs Over Study Period, 2015-2025			
Plant O&M	224	312	21
Rate Impacts	-503	-296	-54
Total	-279	16	-33
Dunkirk Area (Zones A&B)			
Avg. Jobs During Construction, 2014-2017	195	105	154
Avg. Jobs Over Study Period, 2015-2025			
Plant O&M	219	304	21
Rate Impacts	-239	-141	-26
Total	-20	163	-5
Niagara Mohawk Service Territory			
Avg. Jobs During Construction, 2014-2017	208	111	155
Avg. Jobs Over Study Period, 2015-2025			
Plant O&M	220	306	21
Rate Impacts	-482	-284	-52
Total	-262	22	-31
State of New York - Other Economic Indicators *			
Average Over Study Period, 2015-2025 GDP ($2012m)	-$39.7	$8.8	-$2.1
Personal Income ($2012m)	-$9.2	$3.3	-$1.2
Population	-722	-374	1
State Tax Revenue ($2012m)	-$1.2	-$0.1	$0

* Includes average annual impact of construction, O&M spending and rate impacts over the 2015-2025 Study Period.

REDACTED DOCUMENT

Exhibit 8
Jobs Impacts Summary

Summary of overall impact of each solution on jobs each year for the period 2013-2025 (includes short- and long-term impact of construction, on-going O&M spending and rate impacts).



The projected benefits identified by the REMI model for all three solutions would benefit all New York consumers and businesses. To the extent any such benefits from the Repowering Options are actually realized, Niagara Mohawk customers would receive only a portion of them.

Appendix 1 – Redacted

REDACTED

NATIONAL GRID REQUEST FOR PROPOSAL

DUNKIRK REPOWERING OPTIONS

CONFIDENTIAL

Dunkirk Power LLC and NRG Energy, Inc. consider the contents of this document to be Confidential Information, and that therefore, with respect to this document and its contents, National Grid is subject to the confidentiality obligations of the Confidentiality Agreement between NRG Energy, Inc. and National Grid, dated as of November 10, 2011, as amended.

March 26, 2013

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Attachment A: Non-Binding Term Sheet Dunkirk Option 1 [redacted]

Attachment B: Non-Binding Term Sheet Option 2 [redacted]

Attachment C: Non-Binding Term Sheet Option 3 [redacted]

OVERVIEW

NRG Energy, Inc. ("NRG") is pleased to respond to the February 19, 2013 Dunkirk Repowering Request for Proposal ("RFP"), issued by National Grid pursuant to the New York Public Service Commission's ("NYPSC") January 18, 2013 *Order Instituting Proceeding and Requiring Evaluation of Generation Repowering*. NRG proposes three repowering options for the Dunkirk Generating Station ("Dunkirk") located at 106 Point Drive North in Dunkirk, New York, that provide a range of reliability solutions and services at various price points, while maximizing benefits to New York ratepayers.

1. **1x1 Combined cycle gas turbine ("CCGT") and refuel Dunkirk Unit 2 on natural gas** – A new 422 MW CCGT, located on the 230kV network, coupled with a natural gas refueling of the Dunkirk Unit 2 (75 MW) provides high-efficiency generation and reliability services on both the 115kV and 230kV networks while delivering up to $300 million annually in ratepayer savings. The gas-refueled Unit 2 can be in service by [redacted] and the CCGT can be in service by [redacted] assuming a contract for both are awarded by [redacted].

2. **Refuel Dunkirk Units 2, 3 and 4 using natural gas** – A low-cost option to supply 455 MW of generation in Western New York while meeting the reliability needs of the region. In this option, NRG will add natural gas-firing capability to units 2, 3 and 4. Proposed in-service date: [redacted], assuming a contract award by [redacted].

3. **Peaking units –**285 MW of new gas-fired peaking units, capable of full-load operations in 10 minutes that can help meet shifting demand in the Western New York ("WNY") market. Proposed in-service date: [redacted], assuming a contract award by [redacted].

All the above options will provide substantial and long-lived benefits to ratepayers across New York State and will generate substantial economic activity in the WNY region. A more complete benefits discussion follows. The highlights of NRG's proposal include:

- Substantial Ratepayer Savings – A recent independent third-party ratepayer study, which analyzed the effects of the CCGT repowering, identified state-wide ratepayer benefits averaging **$300 million** per year in capacity and energy market savings. Local ratepayer benefits will average nearly **$90 million** per year over the 10 year study period.

- Maximum generating efficiency – The proposed CCGT will be the most efficient gas-fired generating unit in New York, with heat rates of approximately [redacted].

- Improved Emissions Profile – Compared to the existing four-unit Dunkirk facility, all three options provide annual emissions reductions up to 99%, and aggregate emissions reductions up to 6% among all generators across New York State.

- Reliable and Economic Fuel Supply – All three options will access a reliable, low-cost interstate gas pipeline supply. Dunkirk is ideally located near a relatively unconstrained regional natural gas system that has significant redundancy because of the interconnection of several gas pipelines in that region.

- Price Certainty – Engineering and capital cost estimates for all three options are provided on a [redacted], offering significant benefits when evaluating ratepayer risk, project execution risk, and price evaluation. Upon completion of final negotiations with the winning option, NRG will commit to a binding, final price.

- Fast Start Technology – The CCGT and peaker proposals utilize a fast-start design that enhances load-following capabilities that support and complement growing renewable generation resources.

- Adds WNY Jobs – Building the CCGT unit will provide up to 500 jobs during the 36-month construction period and will provide other long-term jobs at the Dunkirk plant.

- Growth Engine for WNY Economy – Ratepayer benefits, a long-term tax base, and long-term jobs identified in a study of the Dunkirk CCGT repowering option will add approximately **$136 million** annually to the WNY economy, and nearly **$350 million** annually across the state.

- Re-Use Existing Infrastructure – Each option will reuse existing land and electrical interconnections and transmission system infrastructure, and each offers the flexibility to configure the interconnections to maintain local reliability while managing for future growth.

- Public Support – Repowering Dunkirk enjoys significant public support from local stakeholders. The PowerUpWNY coalition petitioned Governor Cuomo and the New York Energy Highway Task Force with more than 4,000 signatures supporting a new CCGT project at Dunkirk.

[redacted] The projects proposed here provide a suite of options that improve long-term reliability, provide stability, and offer significant economic development in the region while maximizing ratepayer benefits throughout New York State.

PRICING

[redacted]

[redacted]

	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]

[redacted]

[redacted]

	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]

[redacted]

[redacted]

FINANCING

NRG understands the magnitude of the investment required for any of the options listed above and has the financial resources available to implement all options, on budget and on schedule. Since January 1, 2011, NRG has successfully financed 3,600 MW of development projects on a non-recourse basis, through $6.8 billion of project debt financing, including letter of credit facilities, with competitive terms.

A traditional project financing structure will be used to finance the CCGT or the peaking units (Figure 1). This structure will incent lenders, EPC contractors, and other project stakeholders by providing flexibility with a structure that allows for a proper allocation of commercial risk mitigation.

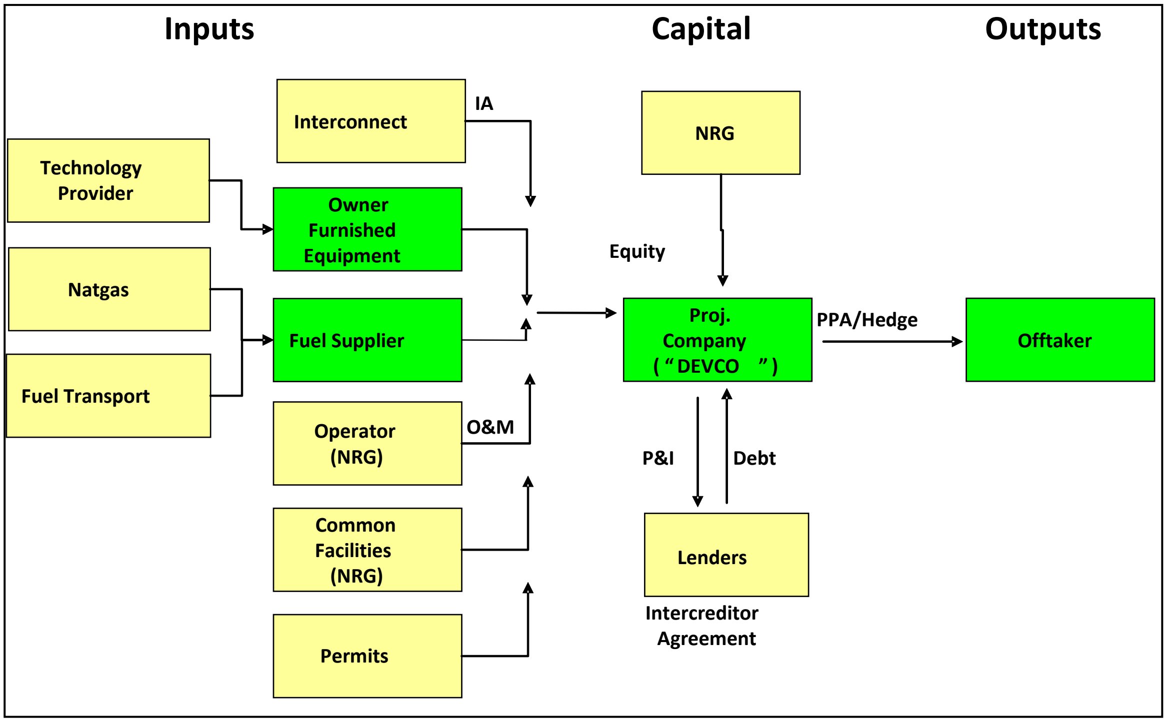

Figure 1. CCGT or Peaking Units Project Structure

[redacted]

Figure 1 indicates the project components that must be executed or be in an advanced stage prior to successfully raising third-party financing. These components include an executed power purchase agreement or hedge with a creditworthy off-taker, as well as interconnection arrangements. To date, initial development and engineering activities have been directly funded by NRG and no project debt has been used or assumed.

Debt financing may include several tranches of debt with various terms and maturities syndicated among a broad range of domestic and international banks and financial institutions. NRG routinely canvasses the lending markets to determine which institutions are receptive to participating in such loan facilities. Several institutions have demonstrated their capability and willingness to serve in a lead role in a project finance syndication. [redacted]

[redacted]

nrg

PROPOSED OPTIONS

Based on the needs identified in the February 19, 2013 RFP, NRG has developed three options for repowering the Dunkirk site. They are:

Dunkirk Repowering Options			
	MW Rating	Technology	[redacted]
1	422	New 1x1 Combined Cycle Generating Turbine	[redacted]
	75	Unit 2 Natural Gas Refueling	[redacted]
2	455	Units 2, 3 and 4 Refueling	[redacted]
3	285	Six Peaking Units	[redacted]

Table 1. Repowering Options

Each option provides reliability support on both the 115kV and 230kV systems and mitigates load shed risk for the system by maintaining two independent generating sources that will be dispatched separately. The following sections describe each option in detail and include proposed technologies, construction plans, permitting timelines, and interconnections.

OPTION 1 – 1X1 CCGT AND UNIT 2 RETROFITTED FOR GAS FIRING

The first option for repowering the Dunkirk coal facility is to build a new CCGT unit with a generating capacity up to 422 MW. The Dunkirk CCGT will be a state-of-the-art, one-on-one combined cycle unit with duct-firing capabilities. In addition to the Dunkirk CCGT, NRG will retrofit Unit 2 (75 MW) so that that unit can fire on natural gas.

The Project will utilize NRG's existing on-site electrical interconnections for Unit 2 on the 115 kV and the CCGT on the 230 kV. Several natural gas pipelines are located within a ten-mile radius of the Dunkirk site and will provide sufficient year-round gas supply.

NRG can retrofit Unit 2 [redacted] and achieve full operations of the CCGT in time for the [redacted] season. Air permitting for the CCGT under the new Article 10 process is expected to take [redacted]. After the full air permit is awarded, the construction phase of the project will take approximately [redacted]. Adding natural gas-firing capability to Unit 2 will require NRG to amend the existing air permit to include natural gas as an allowable fuel source. Modifications to the unit can take place over a [redacted] period; [redacted].

CCGT + Unit 2 Technical Description

The proposed CCGT project uses state-of-the-art generation technology. The CCGT uses a high-efficiency combustion turbine coupled with a dual re-heat heat recovery steam generator and a triple-pressure steam turbine. Closed-cycle wet cooling is included in the reference design. NRG plans to build the CCGT unit on the acreage in front of the existing Dunkirk station.

Advances in CCGT technology enable generation owners to optimize plant characteristics around the needs of the local transmission grid. These needs include maximizing efficiency, delivering fast-start capability, providing sufficient capacity, integrating "peaking" capability through the use of duct burners, and offering ancillary services including automatic generation control and fast ramp rate.

The proposed CCGT project is capable of achieving efficiencies greater than any other facility currently operating in New York State. The proposed CCGT configuration offers a heat rate of approximately [redacted].

The CCGT is also designed to accommodate the various needs of New York's transmission system including the use of fast-start capabilities for wind firming operations, maximizing total on-site capacity. Whatever National Grid's final requirements, NRG will work with multiple technology providers to design the units to deliver the required performance characteristics for the best overall value.

The expected lifespan of a CCGT is generally considered to be 30 years. NRG will operate the CCGT to maximize its lifespan through industry best practices and best-in-class preventative maintenance.

National Grid will be able to direct the supply and draw of reactive power of this unit. Following is a table of expected leading and lagging reactive power that the proposed system could produce:

[redacted]	[redacted]		[redacted]		[redacted]	
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]		[redacted]		[redacted]	
[redacted]	[redacted]		[redacted]		[redacted]	

Table 2. CCGT Reactive Power

NRG also proposes adding natural gas-firing capability to the existing Unit 2 to mitigate the load shed risks and satisfy other 115kV system needs identified by National Grid. The conversion process will require adding gas nozzles to the existing boiler, and making some additional, minor boiler modifications. [redacted].

Electrical Interconnections

NRG has an existing interconnection agreement for the current Dunkirk 1, 2, 3, and 4 generators. All the units are interconnected to the directly adjacent National Grid 115/230 kV substation, with the two smaller units on the 115 kV voltage level and the two larger units at the 230 kV level.

Because the Dunkirk CCGT will use the existing Dunkirk interconnections, this repowering option will also use the existing electric system infrastructure, minimizing costs and construction time. Additionally, NRG holds a total of 593.9 MW of grandfathered capacity deliverability rights at this location which will be transferred to the repowered units. This transfer ensures that the repowering will be eligible to participate in the New York Independent System Operator ("NYISO") capacity market and will not incur costly deliverability upgrades. This further helps reduce costs and increase benefits to consumers.

The CCGT will be subject to the NYISO interconnection study process and will likely interconnect to the 230 kV system while Unit 2 will continue to interconnect to the 115 kV system. NRG believes that the interconnection study process can be expedited because the repowering would replace some of NRG's existing units at the site, and the point-of-interconnection already exists. Accordingly, the interconnection process is expected to proceed normally, and NRG will file an interconnection request with the NYISO sufficiently in advance to meet the proposed 2017 commercial operation date for the CCGT.

Construction Plan

[redacted]

[redacted]

Permitting

[redacted]

[redacted]

[redacted]

SCHEDULE

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

Figure 3. Unit 2 Refueling Schedule

OPTION 2 – NATURAL GAS ADDITIONS TO UNITS 2, 3 AND 4

[redacted]

Natural Gas Addition to Units 2, 3 and 4 Technical Description

NRG currently uses Powder River Basin coal to fuel the existing boilers at Dunkirk. Units 2, 3 and 4 are corner-fired boilers and will be modified to incorporate gas burners in the present location of oil/aux air buckets. The conversion of Dunkirk Units 2, 3 and 4 will add gas-firing capability to the existing station and will retain the flexibility to fire on coal in the future. Net output of the converted Units 2, 3 and 4 on natural gas would remain at 455 MW.

Dunkirk Generation			
	Technology	**COD Year**	**Capacity**
Unit 2	CE Boiler/GE Turbine	1950	75 MW
Unit 3	CE Boiler/GE Turbine	1959	190 MW
Unit 4	CE Boiler/GE Turbine	1959	190 MW
Total			455 MW

Table 3. Existing Dunkirk Units

Interconnection

Units 2, 3 and 4 will maintain their existing interconnection positions on the National Grid 115kV (Unit 2) and 230 kV (Units 3, 4) systems. No additional interconnection work will be required with the proposed modification.

Construction Plan

NRG has significant expertise in the structuring, negotiation, execution and management of EPC of power generation projects and will use this expertise to reduce construction-phase risk and costs. NRG's procurement and construction personnel are skilled at negotiating contracts with vendors and suppliers regionally, nationally and globally to maximize quality, control cost, and control schedule.

[redacted]

Permitting

[redacted]

SCHEDULE

[redacted]

[redacted]

Figure 4. Units 2-4 Gas Refueling Schedule

OPTION 3 – PEAKING PROJECT

NRG believes that the peaking units option will resolve the reliability concerns in the Dunkirk region. [redacted] The modularization of the peaking configuration will provide National Grid incremental resources for reliability needs while mitigating any potential load shed risk issues. The Dunkirk site can accommodate additional peaking units beyond the initial set of six units being proposed. Pricing for additional peaking options will be provided at the request of National Grid or the NYPSC.

Peaking Units Technical Description

[redacted]

[redacted]

[redacted]	[redacted]		[redacted]		[redacted]	
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]		[redacted]		[redacted]	

[redacted]

Electrical Interconnections

The peaking units will be subject to the NYISO interconnection study process and can be configured for interconnection based on the needs of the local transmission system. NRG believes that the interconnection study process will be conducted expeditiously because the point of interconnection already exists, and repowering would replace NRG's existing units at the site. Accordingly, the interconnection process should not delay the construction process and NRG will file an interconnection request with the NYISO sufficiently in advance to meet the [redacted] for the peaking units.

Construction Plan

NRG has significant expertise in the structuring, negotiation, execution and management of EPC of power generation projects and will use this expertise to reduce construction-phase risk and price. NRG's procurement and construction personnel are skilled at negotiating contracts with vendors and suppliers regionally, nationally and globally to maximize quality, limit cost, and control schedule. [redacted]

Permitting

[redacted]

[redacted]

SCHEDULE

[redacted]

[redacted]

Figure 5. Dunkirk Peaking Configuration Schedule

PROJECT BENEFITS

The NYPSC directed National Grid to evaluate the relative costs and benefits of repowering of the Dunkirk facility. Each of NRG's proposed options offers significant and quantified reliability, environmental, and ratepayer benefits.

Option 1, the Dunkirk CCGT, presents a highly-efficient natural gas facility in an area of Western New York with reliability concerns. This project will provide many specific economic benefits to the state of New York through NRG's significant capital investment, including:

- Statewide, ratepayers will see an estimated **$300 million** in energy and capacity cost savings each year for ten years. Production costs will be reduced by **$28 million** each year.
- Emissions will be reduced up to 99% compared to the existing plant, and up to 6% in the aggregate across New York State.
- Even when evaluating the Dunkirk CCGT without these net emissions benefits, the highly-efficient CCGT proposed here will displace higher-emitting units on the New York system. NRG's new units will reduce SOx by as much as 6 percent annually, NOx by as much as 4.5 percent and CO_2 by as much as 1.3 percent statewide.
- The $500+ million capital investment in the CCGT will create an average of 248 jobs per year over the construction period in the Dunkirk region, and more than 3,540 jobs per year during the operations phase throughout the state.

Option 2 – Adding natural gas to Units 2, 3, and 4 also offers ratepayer, environmental and economic benefits.

- Ratepayers in New York will see passed-through savings from capacity cost reductions estimated to be $159 million per year and $1.6 billion over the 10-year period.
- Net annual emissions will be reduced by 90% utilizing natural gas compared to coal.
- The gas addition will make use of existing infrastructure at the plant, preserving existing greenfield land.
- NRG will retain many employees and will preserve the property tax base by continuing to operate a facility at Dunkirk.

Option 3 - Installing gas-fired peaking units also provides benefits in the areas requested by the NYPSC.

- As with the gas conversion, ratepayers will enjoy significant savings from capacity cost reductions, estimated to be $100 million annually.
- Emissions will be reduced by more than 93% annually from those produced by the existing facility.

- Fewer employees will be needed to run the proposed peaking facility; however, there will be significant economic benefits from the capital investment and property tax payments for the area.

Community leaders in and around Dunkirk strongly support the continuation of power generation at Dunkirk because of the associated economic benefits it provides. New York State Senator Catherine Young chairs the PowerUpWNY Coalition, which advocates for the proposed Dunkirk CCGT. The coalition conducts media events that call attention to the need for the plant to remain in the community, and in January 2013 collected signatures from 4,000 area residents interested in seeing Dunkirk repowered with combined-cycle technology.

RATEPAYER BENEFITS

In late 2012, NRG commissioned an independent, third party consultant, Longwood Energy Group, to study the economic and ratepayer impacts from repowering the Dunkirk station with a CCGT. The study concluded that repowering the Dunkirk station could realize an estimated $300 million in annual ratepayer benefits to state and local residents.

According to the study, the Dunkirk CCGT project will lower wholesale electric prices by displacing higher-cost generation in Western New York and across the state. Over the 10 years covered by the analysis, wholesale energy prices will be an average of $1.11/MWh lower with the plant repowered than with it retired. This effect is even more pronounced for Western New York, close to the generator. The average price reduction over the period for the region in the vicinity of Dunkirk (NYISO Zones A and B) is $2.35/MWh.

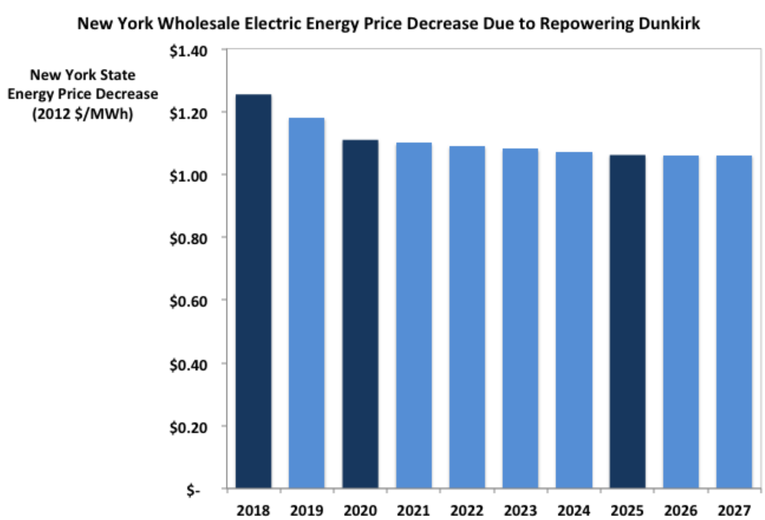

Figure 6. Impact of Repowering Dunkirk on Wholesale Electric Energy Costs.

	Dunkirk Region (Zones A & B)	Total New York State
Energy Market Savings		
Annual	**$87 million/year**	**$300 million/year**
10-Year Total	**$872 million**	**$3.0 billion**
Macroeconomic Benefits		
Gross Regional Product During 10-years Operations	**+ $136 million/year**	**+ $350 million/year**
Total Jobs During Construction	**+ 248 on average**	**$308 on average**
Total Jobs During 10 Years Operations	**+ 1,390/year on average**	**+ 3,540/year on average**

Table 5. Benefits of the Dunkirk CCGT

Another important measure of cost savings is the production cost. Production cost is the generators' cost to produce electricity including variable items such as fuel and emissions and some operations and maintenance costs. The Longwood Energy Group analysis found that average production savings would be $28 million each year, totaling more than $280 million over the 10-year study period.

Ratepayers will enjoy savings in all of the proposed scenarios because of the addition of generation capacity in the state. NRG estimates that market savings for Option 2, the gas conversion, will be similar to those found by Longwood Energy Group for the Dunkirk CCGT – approximately $159 million annually statewide. The peaking units proposed in Option 3 will be $108 million per year in statewide ratepayer savings.

MACROECONOMIC BENEFITS

All the repowering options at the Dunkirk station will provide economic benefits to the region and to New York State. Perhaps the most significant of these benefits will be preserving the property taxes paid by the facility. NRG's Dunkirk station is the largest taxpayer in Dunkirk and Chautauqua County, with payments to Chautauqua County, the city of Dunkirk, and the Dunkirk City School District.

All the options proposed for repowering Dunkirk will maintain a property tax base, if at different levels. In addition, jobs will be created that are directly related to construction and operation of the repowered facility. These jobs and the capital investment in each scenario will extend throughout the economy, providing benefits by way of indirect jobs created and contributions to the gross state and gross regional products.

The Dunkirk CCGT provides the most significant benefits through direct jobs related to construction and operations. Additionally, the ratepayer benefits result in business and household savings that are plowed back into the economy. The independent Dunkirk economic analysis relied on a model developed by Regional Economic Models, Inc., using the capital and operations costs related to building the new Dunkirk plant. Benefits to the local and statewide economy accrue from spending during the construction phase, annual operations and maintenance expenses, and ratepayer benefits due to reduced energy and capacity costs.

NRG is proposing more than $500 million in investment in Dunkirk over the CCGT construction period, resulting in an average of more than 500 jobs per year, generated largely within the region.

The economic effect of building and operating the new Dunkirk plant is magnified when indirect jobs are taken into account. Over the construction and 10-year operation periods studied, about 1,390 jobs will be created annually in the Dunkirk area, and 3,540 on a statewide basis. The gross state product increase mirrors the employment benefits, with $350 million added annually. A substantial portion of this economic growth, $136 million per year, remains in the Dunkirk region.

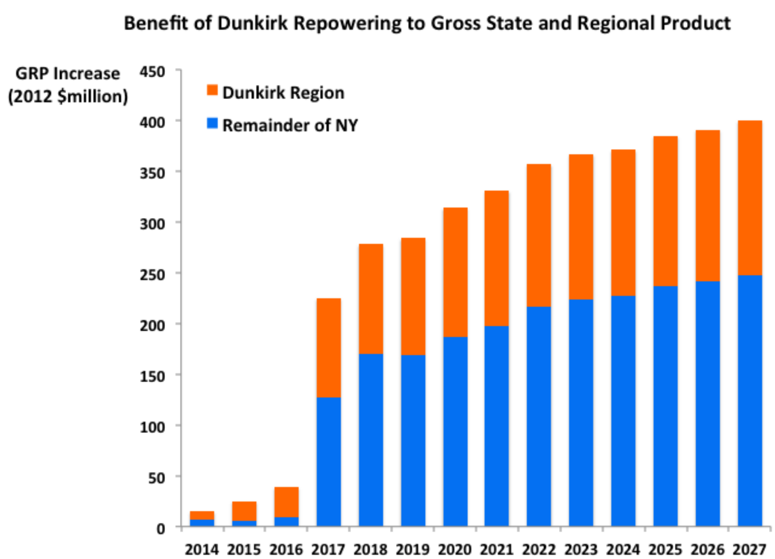

Figure 2. Projected Annual Impact on Gross Regional Product.

Natural gas additions to Units 2, 3 and 4 will retain staff and provide property tax payments in Dunkirk as opposed to retiring the plant. Installing Peaking Units at Dunkirk will involve a capital investment of about $300 million.

All the options proposed by NRG will result in economic benefits related to construction as well as operation. Many of these benefits flow directly to the surrounding community during construction and ongoing operations. Transmission upgrades will not deliver these benefits, which multiply throughout the community as well as the state.

ENVIRONMENTAL BENEFITS

NRG's proposed Options at Dunkirk will all provide considerable environmental benefits through emissions reductions. In addition, the repowered facility in all cases will use the existing facility and resources, and require few or no land or water use changes.

EMISSIONS

Replacing the existing coal plant with a new, state-of-the-art CCGT will provide significant environmental benefits to the local community. While NRG's existing Dunkirk coal units are among the cleanest coal-fired units in the country, the high efficiency of the new CCGT units coupled with the environmental profile of natural gas produce far fewer emissions per kilowatt produced – which means fewer emissions for the residents of Dunkirk and all of Western New York. NRG estimates that the emissions reductions for Option 1, which includes gas additions to Unit 2, would be an average of 81% compared to the existing plant. In particular, emissions of sulfur dioxide, the precursor of acid rain, and nitrogen oxide, the precursor to ground-level ozone and smog, would be reduced 95% and almost 100%, respectively.

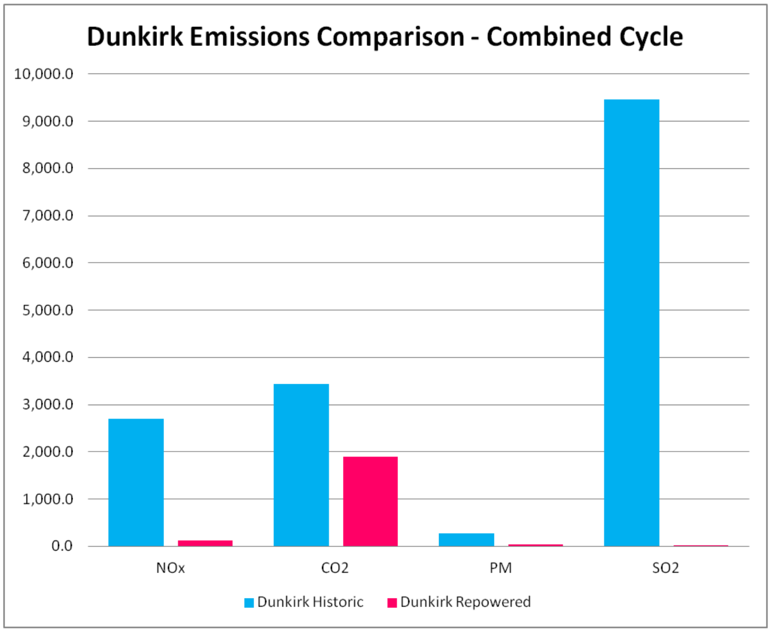

Figure 3. Comparative Emissions of Existing and New Dunkirk Facility

Adding a highly-efficient combined cycle natural gas plant in Western New York will also decrease emissions statewide. A clean, efficient Dunkirk plant will be dispatched ahead of less-efficient and higher emitting generators. Independent analysis shows that particularly in the earlier years before additional wind energy plants come online to meet New York State renewable energy targets[1], the Dunkirk CCGT would reduce sulfur dioxide and nitrogen oxide, as well as carbon dioxide, the leading greenhouse gas, across the state.

[1] NY State Transmission Assessment & Reliability Study (STARS) Phase II Study Report; Apr. 30, 2012; pg 28.

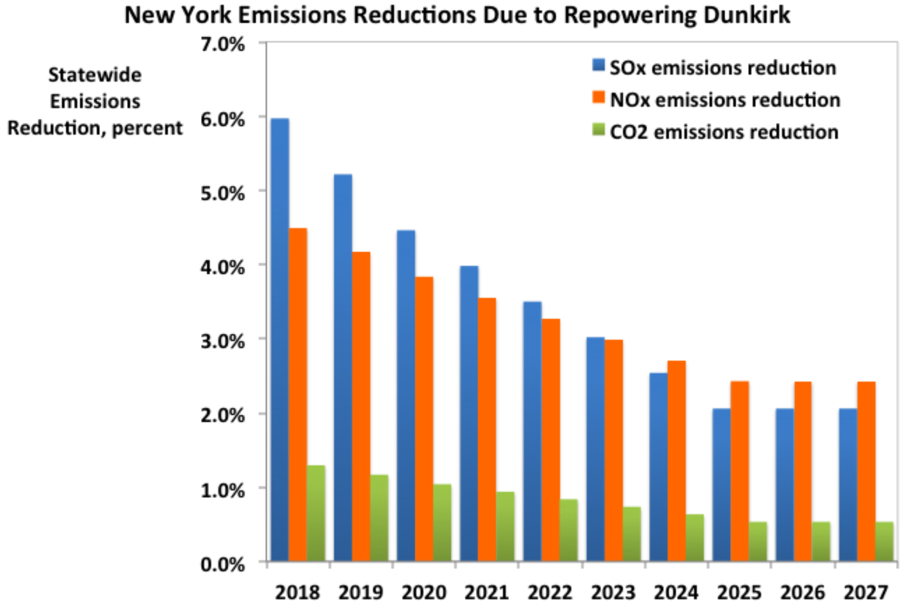

Figure 4. Emissions Reductions from a Dunkirk CCGT

Option 2, a gas addition to three of the existing coal units would also have significant emissions benefits compared to the current Dunkirk facility. Annual emissions of nitrogen oxide, carbon dioxide, particulate matter, and sulfur dioxide will be reduced by about 90% overall.

[redacted]

Figure 5. Gas Conversion Emissions Benefits

The peaking units presented in Option 3 will have similar environmental benefits related to the use of natural gas rather than coal as fuel. [redacted]

Supporting Increased Wind Energy Installations

Each of NRG's proposed options will support the anticipated expansion of wind generation in Western New York. The recent New York State Transmission Assessment and Reliability Study modeled wind generation in New York, showing it growing from 1300 MW today to 6000 MW, and some estimates project as much as 8,000 MW of wind by 2030.[2] Much of this capacity would come from Western New York.

[2] NY State Transmission Assessment & Reliability Study (STARS) Phase II Study Report; Apr. 30, 2012; pg 28.

This is relevant because the intermittent nature of wind generation results in unpredictable generating patterns that create challenges for grid operators. A recent New York State Energy Research and Development Authority ("NYSERDA") study identified the challenges with incorporating large scale wind into the existing system:

> "The bulk power system will experience higher magnitude ramping events, and to accommodate the increased variability and uncertainty of variable generation the system will need to commit proportionately more dispatchable resources to maintain system flexibility.[3]"

The NYSERDA study indicates that facilities such as those proposed by NRG will provide a great deal of that ramping capability.[4] Additionally, falling natural gas prices and increasing environmental restrictions continue to stress New York coal plant power generation. With declining conventional generation capacity in-state, there is an increasing need for units that can provide ramping services to balance wind integration on the system.

The Dunkirk CCGT, if equipped with fast-start technology, will best compliment additional renewable development in the region, helping the state meet renewable energy objectives while ensuring National Grid has all the tools it needs to stabilize grid supply. New CCGT technology is capable of 10-minute response and flexible load following capabilities to respond to changing grid conditions. This technology offers both a reliability and economic benefit because it reduces the potential for out-of-merit costs that might otherwise be incurred with other, less flexible resources that require advanced start up and prolonged minimum run times.

Land and Water Use

Land use and water use will not be significantly altered with any of the options proposed because all three of NRG's proposals will use land already within the boundaries of the current Dunkirk plant. No additional land acquisition and disturbance will be necessary. The use of natural gas rather than coal as fuel will also decrease coal transportation traffic even though the infrastructure will remain in place.

The Dunkirk plant currently uses a once-through cooling process. However, the CCGT proposed in Option 1 will include a new evaporative-cooling system in order to comply with existing NY State DEC policy for new generation. Unit 2 will continue to utilize the existing cooling system, which has been upgraded to meet Best Technology Available, employing the use of fine mesh travelling screens.

Option 2 will utilize the existing cooling system which has been recently upgraded to meet Best Technology Available, utilizing state-of-the-art fine mesh traveling screens.

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[3] New York ISO; June 2010; NYISO Wind Generation Study; pg. 4.
[4] New York ISO; June 2010; NYISO Wind Generation Study; pg. 32.

Option 3 peaking units are simple cycle and will not require cooling water.

The Dunkirk facility is within an Environmental Justice review area and NRG will comply with the appropriate Environmental Justice review process as regulated.

LOCAL SUPPORT

PowerUpWNY (Power Up Western New York) is a coalition of business, labor, and civic groups and local and state politicians focused on supporting smart, long-term energy projects in Western New York. Chaired by New York State Senator Catharine Young (R, C, I, Olean), PowerUpWNY strongly backs the repowering of the existing Dunkirk plant with modern and efficient combined-cycle technology. The Coalition also broadly supports Governor Cuomo's plan to build an "Energy Highway."

Other members of the Coalition include New York Assemblyman Andy Goodell; IBEW Local 97; Mayor of Dunkirk Al Dolce; Chautauqua County Executive Greg Edwards; William Daley, CEO and Rich Dixon, CFO of the Chautauqua County Industrial Development Agency; Jay Gould, Chairman of the Chautauqua County Legislature; Chautauqua County Chamber of Commerce; United Way of Northern Chautauqua County; Dunkirk Area Central Labor Council; Sheet Metal Workers Local 112; IBEW Local 106; the Buffalo Building and Construction Trades Council; the Southwestern NY Building and Construction Trades Council; Northeast Regional Council of Carpenters; Eastern Millwright Regional Council; and SUNY Fredonia.

In January 2013, PowerUpWNY sent more than 4,000 signatures to Governor Andrew Cuomo and the Energy Highway Task Force members in support of repowering the Dunkirk facility because of the benefits identified by the coalition:

- Keeping energy investment in-state
- Improving the reliability of the electrical grid in Western New York
- Preserving jobs
- Generating dramatically cleaner energy
- Increasing electrical system efficiency
- Ensuring a predictable and stable tax base in Chautauqua County and Dunkirk
- Providing support for renewable energy generation such as wind power

Attachment A

[redacted]

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Attachment A

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Attachment B

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Attachment B

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Attachment C

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Attachment C

[redacted]

Appendix 2 – Redacted

Request Date: March 29, 2013 Request No. NMPC-1
Due Date: April 15, 2013

Case No. 12-E-0577 – Proceeding on Motion of the Commission to Examine Repowering Alternatives to Utility Transmission Reinforcements

Request for Information

From: Niagara Mohawk Power Corporation d/b/a National Grid

To: NRG Energy, Inc.

Request: Property Taxes

Each of the three proposed repowering options states that property taxes will be treated as a "pass-through expense" to the buyer.

a. [redacted]
b. Describe the basis of and/or method used for such estimate in (a), above.
c. Provide the schedule of payments under the Payment in Lieu of Taxes agreement between NRG and Chautauqua County Industrial Development Agency.

Response:

a) [redacted]

[redacted]

b) See response to (a) above.

c) The tax schedule is shown as Attachment A to this response.

Name of Respondent: Date of Reply:

Jonathan Baylor April 15, 2013

Request Date: March 29, 2013 Request No. NMPC-2
Due Date: April 15, 2013

Case No. 12-E-0577 – Proceeding on Motion of the Commission to Examine Repowering Alternatives to Utility Transmission Reinforcements

Request for Information

From: Niagara Mohawk Power Corporation d/b/a National Grid

To: NRG Energy, Inc.

Request: Economic impacts

a. Provide all analyses that support the statement noted in Option #1 benefits that "Statewide, ratepayers will see an estimated $300 million in energy and capacity cost savings each year for ten years. Production costs will be reduced by $28 million each year."
b. Provide all analyses that support the statement noted in Option #1 benefits that "The $500+ million capital investment in the CCGT will create an average of 248 jobs per year over the construction period in the Dunkirk region, and more than 3,540 jobs per year during the operations phase throughout the state."
c. Under Option1 on page 18 out of the 3540 jobs per year created throughout the state, please provide the number of NRG employees and contract employees that will be permanent employees working at the generator site when units are in service and operating.
d. Provide all analyses that support the statement noted in Option #2 benefits that "Ratepayers in New York will see passed-through savings from capacity cost reductions estimated to be $159 million per year and $1.6 billion over the 10-year period."
e. Provide all analyses that support the statement noted in Option #3 benefits that "ratepayers will enjoy significant savings from capacity cost reductions, estimated to be $100 million annually."
f. Provide the analysis and study of the independent, third party consultant, Longwood Energy Group, referenced on page 19 of the Repowering Proposal. Include all generator assumptions regarding plant retirements, additions, and repowering projects reflected in the analysis and study.

Response:

a) Attachment B to this response is the Longwood Energy Group ("LEG Report") study on the Dunkirk Repowering. The study provides lengthy discussions on the methodology and data used in their analysis of the market impacts.

The approximately $300 million annual savings amount is comprised of two components: $142 million per year in energy cost savings (pg. 11 of the LEG Report) and $159 million per year in capacity cost savings (pg. 12 of the LEG Report). The $28 million annual production cost savings is presented on page 11 of the LEG Report. The energy and capacity cost analyses are described in detail in the LEG Report. [redacted]

b) [redacted]

Based on information supplied by NRG, the LEG Report concluded that 26% of construction phase spending was modeled to occur in the Dunkirk/Western New York Region, the majority of which related to labor expense from construction activities.

c) During the operations phase of the CCGT project, NRG estimates that there will be [redacted] full-time equivalents at the Dunkirk site, and approximately [redacted] million per year of operations expense would be serviced from the Dunkirk/Western New York region.

d) The LEG Report evaluated the impact of a 440MW CCGT unit on the capacity and energy markets in New York, and is reflected in the proposal submitted to National Grid as Option 1. Option 2 proposes a capacity contract for 455 MW of gas-fired boilers from Units 2, 3 and 4. NRG used the LEG Report as a proxy for determining what the capacity market impacts would be because the impacts of both options would be similar. NRG believes the total ratepayer impact is higher than the $189 million if energy market benefits are included. NRG has not conducted that detailed analysis due to timing constraints.

e) NRG used the LEG Report identified capacity impacts ($189 million/year) from the CCGT and scaled the benefits to account for the impacts from the proposed peaker units in Option 3. The proposed 285 MW from Option 3 are approximately 65% of the proposed 440 MW from Option 1 which was studied in the LEG Report. Applying that 65% factor to the capacity market impacts yielded an estimated capacity price benefit of $100 million. NRG believes the total ratepayer impact is higher than the $100 million if energy market benefits are included. NRG has not conducted that detailed analysis due to timing constraints.

f) Attachment C is a list of assumed generator additions and retirements used by Longwood Energy in its preparation of the LEG Report.

<u>Name of Respondent:</u>	<u>Date of Reply:</u>
Jonathan Baylor	April 15, 2013

Request Date: March 29, 2013 Request No. NMPC-3
Due Date: April 15, 2013

Case No. 12-E-0577 – Proceeding on Motion of the Commission to Examine Repowering Alternatives to Utility Transmission Reinforcements

Request for Information

From: Niagara Mohawk Power Corporation d/b/a National Grid

To: NRG Energy, Inc.

Request: Economic impacts

a. Provide the independent third party ratepayer study, referred to on page 3, which identified state-wide ratepayer electricity cost savings of $300 million per year and local ratepayer savings of $90 million per year.
b. Please provide the REMI "policy variables" and Results table showing the Energy Market Savings and Macroeconomic Benefits figures on Table 5 of page 20.
c. Regarding the employment impacts shown on Table 5 of page 20, please provide the number of permanent workers that will be employed directly at the Dunkirk power plant facility upon completion of the project.
d. Do the macroeconomic benefits shown on Table 5 of page 20 include lost jobs and incomes at New York power plants whose output would be displaced by output of the repowered Dunkirk facility?
e. Are there any project costs that are not reflected in the estimated $300 million per year state-wide and $87 million per year local rate payer electricity cost savings, shown on Table 5 of page 20?
f. Please separate the annual "Energy Market Savings" identified on page 25 in terms of capacity market savings and energy market savings.
g. Please provide all assumptions, workpapers, and analyses showing how the estimates of jobs created (pages 18 and 20) were calculated, for the construction period jobs in the Dunkirk region and the jobs throughout the state during the operations phase.

Response:

a) Attachment B to this response is the Longwood Energy Group ("LEG Report") study on the Dunkirk Repowering. The study provides lengthy discussions on the methodology and data used in their analysis of the market impacts.

b) The REMI model is licensed to Longwood Energy Group for the purposes of the study and is not the work product of NRG. Upon information and belief the policy variables input into the model are included in the table below. [redacted]

[redacted]

[redacted]	[redacted]	[redacted]
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[redacted]

[redacted]

c) During the operations phase of the CCGT project, NRG estimates that there will be [redacted] full-time equivalents at the Dunkirk site.

d) Total jobs impact is calculated based on economic activity from the plant (estimated at [redacted] million per year) and from regional and statewide ratepayer savings of $300 million per year as determined by the REMI model. The model assumes only jobs impacts from Dunkirk CCGT project and subsequent ratepayer savings. Jobs from existing energy production facilities across the state are not included, as most jobs are considered fixed costs and not dependent on the capacity factors of the related existing unit.

e) No, all project costs are included in the analysis.

f) Energy Market Savings are the sum of capacity market benefits ($159 million per year) and energy market savings ($142 million per year). Further information on the calculation of the benefits can be found in Attachment B to this response.

g) Refer to methodology and assumptions as described in the LEG Report (Attachment B)

Name of Respondent:	Date of Reply:
Jonathan Baylor	April 15, 2013

Request Date: March 29, 2013 Request No. NMPC-4
Due Date: April 15, 2013

Case No. 12-E-0577 – Proceeding on Motion of the Commission to Examine Repowering Alternatives to Utility Transmission Reinforcements

Request for Information

From: Niagara Mohawk Power Corporation d/b/a National Grid

To: NRG Energy, Inc.

Request: Project timing

Estimated schedules for all three options are based on an assumed "contract award by [redacted]." Please provide schedules for each option assuming contract awards by:

a. [redacted]
b. [redacted]

Response:
NRG will make every effort to ensure the commercial operations dates of each proposed option are achieved as proposed. However, the following table demonstrates the estimated in-service dates based on the scenarios proposed above.

[redacted]

Name of Respondent:	Date of Reply:
Jonathan Baylor	April 15, 2013

Request Date: March 29, 2013 Request No. NMPC-5
Due Date: April 15, 2013

Case No. 12-E-0577 – Proceeding on Motion of the Commission to Examine Repowering Alternatives to Utility Transmission Reinforcements

Request for Information

From: Niagara Mohawk Power Corporation d/b/a National Grid

To: NRG Energy, Inc.

Request: Licensing and permitting (Options 1 and 3)

a. Please provide a detailed timeline of the Article 10 process, including statutory milestones (PIP, Scoping Document, Application, Approval, Air Permitting, etc.) as well as the air permitting process.
b. [redacted]
c. Please describe what emission control technology would be required and expected emission rate limits.
d. Please provide more details for the proposed emission reductions-tons and emission rates. Are the expected reductions calculated from current Dunkirk emissions (tons) or emission rates? (Page 18, 22, 23).
e. Please describe any analyses performed to determine if there are there any land use (wetlands, endangered species)/contamination issues that could impact the project schedule once construction begins and the results of any such analyses.
f. Please address whether the technologies chosen will meet GHG BACT under the Tailoring Rule.

Response:

a) The projected timeline for the Article 10 certification process that would address the CCGT project component of Option 1, and Option 3, is provided below. The NYDEC air permitting process for the 75MW Unit 2 gas conversion is also provided below and will begin once a contract with National Grid is executed.

[redacted]

[redacted]

c) Existing Unit 2 is controlled with SNCR technology and is able to achieve NOx emissions rates below the existing limits of [redacted] in the air permit. The new units (CCGT and peakers) will be equipped with selective catalytic reduction ("SCR") technology for NOx control and a CO catalyst for the control of volatile organic compounds ("VOC's") and CO. NRG will use Lowest Achievable Emission Rate ("LAER") or Best Available Control Technology ("BACT") for all criteria pollutants.

[redacted]

f) The technologies proposed will meet GHG BACT requirements. Additionally, the recently promulgated NYSDEC Part 251 regulations require new technologies under Article 10 to meet stringent GHG emission limits based on either an emissions output (lbs/MWh) or fuel input (lbs/mmBtu) basis. The technologies chosen will comply with Part 251.

Name of Respondent: Date of Reply:

Thomas Coates April 15, 2013

Request Date: March 29, 2013 Request No. NMPC-6
Due Date: April 15, 2013

Case No. 12-E-0577 – Proceeding on Motion of the Commission to Examine Repowering Alternatives to Utility Transmission Reinforcements

Request for Information

From: Niagara Mohawk Power Corporation d/b/a National Grid

To: NRG Energy, Inc.

Request: Article VII

[redacted]

Response:

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

Name of Respondent: Date of Reply:

Jonathan Baylor April 15, 2013

Request Date: March 29, 2013 Request No. NMPC-7
Due Date: April 15, 2013

Case No. 12-E-0577 – Proceeding on Motion of the Commission to Examine Repowering Alternatives to Utility Transmission Reinforcements

Request for Information

From: Niagara Mohawk Power Corporation d/b/a National Grid

To: NRG Energy, Inc.

Request: Licensing and permitting (Option 1)

a. Will the air permit for the gas refueled Unit 2 be included as part of the Article 10 process, or does the proposal assume this air permit modification will proceed independently from the rest of the project?
b. Please clarify the status of the SPDES permit in relation to 316(b). Has the DEC 316(b) determination been made and incorporated into the SPDES permit and are fine mesh fish friendly screens the only technology required? (Page 24)
c. Closed cycle wet cooling is included in the reference design.
    i. What is the source of the make-up water?
    ii. What is the source of the Intakes?
    iii. Will this require a SPDES permit modification?
    iv. Describe NRG's assumptions regarding the SPDES process and how it is reflected in the project design and schedule.

Response:

[redacted]

[redacted]

[redacted]

[redacted]

Name of Respondent:	Date of Reply:
Thomas Coates	April 15, 2013

Request Date: March 29, 2013 Request No. NMPC-8
Due Date: April 15, 2013

Case No. 12-E-0577 – Proceeding on Motion of the Commission to Examine Repowering Alternatives to Utility Transmission Reinforcements

Request for Information

From: Niagara Mohawk Power Corporation d/b/a National Grid

To: NRG Energy, Inc.

Request: Licensing and permitting (Option 2)

a. What did NRG assume regarding air modeling to evaluate compliance with the 1 hour NO2 NAAQS?
b. How will the units comply with the NOx RACT limits effective July 1, 2014?
c. What are the expected NOx emission rates resulting from gas conversion?
d. Please provide more details for the proposed emission reductions-tons and emission rates.
   i. Are the expected reductions calculated from current Dunkirk emissions?
   ii. [redacted]

Response:

[redacted]

[redacted]

[redacted]

[redacted]

Name of Respondent: Date of Reply:

Thomas Coates April 15, 2013

Request Date: March 29, 2013 Request No. NMPC-9
Due Date: April 15, 2013

Case No. 12-E-0577 – Proceeding on Motion of the Commission to Examine Repowering Alternatives to Utility Transmission Reinforcements

Request for Information

From: Niagara Mohawk Power Corporation d/b/a National Grid

To: NRG Energy, Inc.

Request: Reliability

Referring to the first sentence on page 18 of the proposal, please provide the quantified reliability benefits.

Response:
When the term quantified reliability benefits was used in the Proposal, NRG was referring, in general, to the analysis and conclusions reached by National Grid in its studies concerning the reliability needs in the Dunkirk area.

Name of Respondent:	Date of Reply:
Jonathan Baylor	April 15, 2013

Request Date: March 29, 2013 Request No. NMPC-10
Due Date: April 15, 2013

Case No. 12-E-0577 – Proceeding on Motion of the Commission to Examine Repowering Alternatives to Utility Transmission Reinforcements

Request for Information

From: Niagara Mohawk Power Corporation d/b/a National Grid

To: NRG Energy, Inc.

Request: Reliability (Option 1)

a. Will the design of the combined cycle unit be such that if one of the generators trips, the other generator must also shut down?
b. Is there any common equipment, electrical or mechanical, whose failure could result in an outage to both machines?
c. Please explain whether the steam generator can continue to run if the combustion turbine trips or is otherwise not available, and whether the combustion turbine can continue to run if the steam generator trips or is otherwise not available.
d. If both machines can run independently of the other please describe any limitations on output or duration associated with operating in this fashion.

Response:

[redacted]

[redacted]

c) See detail in (a) above

[redacted]

Name of Respondent: Date of Reply:

Jonathan Baylor April 15, 2013

Request Date: March 29, 2013 Request No. NMPC-11
Due Date: April 15, 2013

Case No. 12-E-0577 – Proceeding on Motion of the Commission to Examine Repowering Alternatives to Utility Transmission Reinforcements

Request for Information

From: Niagara Mohawk Power Corporation d/b/a National Grid

To: NRG Energy, Inc.

Request: Reliability (Option 1)

a. Please describe the proposed configuration for the interconnection (page 11) of the CCGT to the 230 kV system.
b. How many step-up transformers would be necessary and to what 230 kV bus sections at Dunkirk would these transformers connect?
c. Please provide an estimate of the start up, minimum run and shut down times for the CCGT.
d. On page 4, the proposal states that “The CCGT and peaker proposals utiilize a fast-start design," but on page 24 the proposal says, "if equipped with fast-start technology." Please clarify whether fast-start technology is included in the proposal and is included in the pricing in the term sheet, and if not, indicate how addition of fast-start technology would alter the term sheet for Option 1.
e. Would the refueled unit 2 in Option 1 have the same start up, minimum run and shut down times as provided for this unit for Option 2?
f. [redacted]

Response:

[redacted]

[redacted]

[redacted]

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[redacted]

e) Yes

[redacted]

<u>Name of Respondent:</u>	<u>Date of Reply:</u>
Jonathan Baylor	April 15, 2013

Request Date: March 29, 2013 Request No. NMPC-12
Due Date: April 15, 2013

Case No. 12-E-0577 – Proceeding on Motion of the Commission to Examine Repowering Alternatives to Utility Transmission Reinforcements

Request for Information

From: Niagara Mohawk Power Corporation d/b/a National Grid

To: NRG Energy, Inc.

Request: Reliability (Option 2)

What would be the start up, minimum run and shut down times of the refueled units?

Response:
The start up, minimum run and shut down times for Units 2, 3 and 4 under all scenarios are listed in Attachment E.

Name of Respondent: Date of Reply:

Jonathan Baylor April 15, 2013

Request Date: March 29, 2013 Request No. NMPC-13
Due Date: April 15 2013

Case No. 12-E-0577 – Proceeding on Motion of the Commission to Examine Repowering Alternatives to Utility Transmission Reinforcements

Request for Information

From: Niagara Mohawk Power Corporation d/b/a National Grid

To: NRG Energy, Inc.

Request: Reliability (Option 3)

a. Please provide a supplement to Option 3 to increase the number of units to provide a minimum total of [redacted] of generation for the entire plant.
b. What is NRG's assumption regarding the maximum number of hours the peaking units will be permitted to run, on a daily and annual basis? If necessary, provide the information on the basis of representative equipment.

Response:

a) NRG will require an additional 45 days to provide an updated estimate to expand the scope of the peaker proposal to [redacted] on site.

b) [redacted]

Name of Respondent: Date of Reply:

Jonathan Baylor April 15, 2013

Request Date: March 29, 2013 Request No. NMPC-14
Due Date: April 15, 2013

Case No. 12-E-0577 – Proceeding on Motion of the Commission to Examine Repowering Alternatives to Utility Transmission Reinforcements

Request for Information

From: Niagara Mohawk Power Corporation d/b/a National Grid

To: NRG Energy, Inc.

Request:

a. Please provide the termination date of NRG's "capacity deliverability rights" referenced on Page 11.
b. Please provide the relevant sections in the NYISO's tariff that will ensure units with COD June 2017 will be able to use NRG's existing "capacity deliverability rights" as referenced on Page 11.

Response:
With regard to deliverability rights (aka CRIS), the NYISO tariff OATT Attachment S, Section 25.9.3.1 Retaining CRIS Status, states:

In the case of a deactivation, CRIS status at the capacity level eligible for CRIS found deliverable terminates three years after deactivation unless the deactivated Large Facility or Small Generating Facility takes one of the following actions before the end of the three-year period: (1) returns to service and participation in NYISO capacity auctions or bilateral transactions, or (2) transfers capacity deliverability rights to another Large Facility or Small Generating Facility at the same or a different electrical location that becomes operational within three years from the deactivation of the original facility.

Additionally, this section establishes that:

a facility becomes deactivated on the last day of the month during which (i) it ceases to offer capacity into NYISO capacity auctions, or (ii) it ceases to be registered as a Capacity Resource for a Load Serving Entity through a bilateral transaction(s) or self-supply arrangement.

Unit 3 and Unit 4 were deactivated in September 2012, so the deliverability rights will expire three years from that date. As of this time Dunkirk Unit 1 and Unit 2 are not deactivated. As such the deliverability rights associated with these units have no defined expiration date. If at some future point they were deactivated, the rights would expire three years from the tariff specified deactivation date.

Note that with the expected creation of a new Hudson Valley capacity zone by the NYISO, the binding deliverability constraint across the UPNY-SENY interface will be removed from the ROS deliverability test. The NYISO's latest Class Year 2011 Deliverability Study[1] shows over 1150 MW of excess deliverability headroom exists on the system for the interfaces that would remain in the ROS area. This suggests that transfer of CRIS rights may be unnecessary. Further, the expiration of any Dunkirk rights would cause them to be released to the system thereby adding to the current excess deliverability headroom on the system.

Finally, the Dunkirk deactivations are the result of placing the units in a temporary mothball state and NRG maintains the option to return the units to service in the event a transfer of CRIS rights was necessary to ensure deliverability of the repowered units beyond a three year expiration deadline.

Name of Respondent:	Date of Reply:
Jonathan Baylor	April 15, 2013

[1] See NYISO April 15, 2013 Interconnection Project Facilities Study Working Group – Presentation - Class Year 2011 Deliverability
https://www.nyiso.com/secure/webdocs/markets_operations/committees/oc_ipfswg/meeting_materials/2013-04-15/CY2011_DIS_April152013_IPFSWG_rev0.pdf

Attachment A to NRG Energy, Inc.
Response to NMPC-1

			Base Payments per the Agreement				
PILOT Year	**Assmt Year**	**Notif. Date**	**Dec. Pymt Due**	**Amount**	**Jan. Pymt Due**	**Amount**	**%MW Capacity**
1	2008	2/1/08	12/31/08	$ 5,090,000	1/31/09	$ 4,000,000	0%
2	2009	2/1/09	12/31/09	$ 5,423,518	1/31/10	$ 4,000,000	0%
3	2010	2/1/10	12/31/10	$ 6,400,000	1/31/11	$ 4,000,000	0%
4	2011	2/1/11	12/31/11	$ 6,400,000	1/31/12	$ 4,386,000	0%
5	2012	2/1/12	12/31/12	$ 4,214,000	1/31/13	$ 4,284,000	0%
6	2013	2/1/13	12/31/13	$ 4,116,000	1/31/14	$ 4,182,000	0%
7	2014	2/1/14	12/31/14	$ 4,018,000	1/31/15	$ 4,131,000	0%
8	2015	2/1/15	12/31/15	$ 3,969,000	1/31/16	$ 4,213,620	0%
9	2016	2/1/16	12/31/16	$ 4,048,380	1/31/17	$ 4,297,892	85%
10	2017	2/1/17	12/31/17	$ 4,129,348	1/31/18	$ 4,383,850	85%
11	2018	2/1/18	12/31/18	$ 4,211,935	1/31/19	$ 4,471,527	85%
12	2019	2/1/19	12/31/19	$ 4,296,173	1/31/20	$ 4,560,958	85%
13	2020	2/1/20	12/31/20	$ 4,382,097	1/31/21	$ 4,652,177	85%
14	2021	2/1/21	12/31/21	$ 4,469,739	1/31/22	$ 4,745,221	85%
15	2022	2/1/22	12/31/22	$ 4,559,133	1/31/23	$ 4,840,125	85%
16	2023	2/1/23	12/31/23	$ 4,650,316	1/31/24	$ 4,936,928	85%
17	2024	2/1/24	12/31/24	$ 4,743,323	1/31/25	$ 5,035,666	85%
18	2025	2/1/25	12/31/25	$ 4,838,189	1/31/26	$ 5,136,379	85%
19	2026	2/1/26	12/31/26	$ 4,934,953	1/31/27	$ 5,239,107	0%
20	2027	2/1/27	12/31/27	$ 5,033,652	1/31/28	$ 5,343,890	0%
				$ 93,927,756		$ 90,840,340	

Notes:
The allocation between School and City/County was derived using the 2007 Assessment Year taxes, which we

[redacted]

Attachment A to NRG Energy, Inc.
Response to NMPC-1

[redacted] a

[redacted]

Dec. Pymt Due	Amount	Jan. Pymt Due	Amount	Total	[redacted]	School Tax
12/31/08	$ -	1/31/09	$ -	$ -	2008 - 2009	$ -
12/31/09	$ -	1/31/10	$ -	$ -	2009 - 2010	$ -
12/31/10	$ -	1/31/11	$ -	$ -	2010 - 2011	$ -
12/31/11	$ -	1/31/12	$ -	$ -	2011 - 2012	$ -
12/31/12	$ -	1/31/13	$ -	$ -	2012 - 2013	$ -
12/31/13	$ -	1/31/14	$ -	$ -	2013 - 2014	$ -
12/31/14	$ -	1/31/15	$ -	$ -	2014 - 2015	$ -
12/31/15	$ -	1/31/16	$ -	$ -	2015 - 2016	$ -
12/31/16	$ 3,437,304	1/31/17	$ 3,649,154	$ 7,086,457	2016 - 2017	$ 3,468,767
12/31/17	$ 3,506,050	1/31/18	$ 3,722,137	$ 7,228,187	2017 - 2018	$ 3,538,143
12/31/18	$ 3,576,171	1/31/19	$ 3,796,580	$ 7,372,751	2018 - 2019	$ 3,608,906
12/31/19	$ 3,647,694	1/31/20	$ 3,872,512	$ 7,520,206	2019 - 2020	$ 3,681,084
12/31/20	$ 3,720,648	1/31/21	$ 3,949,962	$ 7,670,610	2020 - 2021	$ 3,754,706
12/31/21	$ 3,795,061	1/31/22	$ 4,028,961	$ 7,824,023	2021 - 2022	$ 3,829,800
12/31/22	$ 3,870,962	1/31/23	$ 4,109,540	$ 7,980,502	2022 - 2023	$ 3,906,396
12/31/23	$ 3,948,382	1/31/24	$ 4,191,731	$ 8,140,113	2023 - 2024	$ 3,984,524
12/31/24	$ 4,027,350	1/31/25	$ 4,275,565	$ 8,302,915	2024 - 2025	$ 4,064,214
12/31/25	$ 4,107,896	1/31/26	$ 4,361,077	$ 8,468,973	2025 - 2026	$ 4,145,498
12/31/26	$ -	1/31/27	$ -	$ -	2026 - 2027	$ -
12/31/27	$ -	1/31/28	$ -	$ -	2027 - 2028	$ -
	$ 37,637,519		$ 39,957,218			

ɜre the allocations present when the PILOT Agmt was executed. This is for Accounting purposes only.

[redacted]

Attachment A to NRG Energy, Inc.
Response to NMPC-1

see notes	b	*see notes*	c	a+b+c
32.34%		18.71%		
City Year	**City Tax**	**County Year**	**County Tax**	**Total**
2009	$ -	2009	$ -	$ -
2010	$ -	2010	$ -	$ -
2011	$ -	2011	$ -	$ -
2012	$ -	2012	$ -	$ -
2013	$ -	2013	$ -	$ -
2014	$ -	2014	$ -	$ -
2015	$ -	2015	$ -	$ -
2016	$ -	2016	$ -	$ -
2017	$ 2,291,465	2017	$ 1,326,224	$ 7,086,457
2018	$ 2,337,295	2018	$ 1,352,749	$ 7,228,187
2019	$ 2,384,041	2019	$ 1,379,804	$ 7,372,751
2020	$ 2,431,722	2020	$ 1,407,400	$ 7,520,206
2021	$ 2,480,356	2021	$ 1,435,548	$ 7,670,610
2022	$ 2,529,963	2022	$ 1,464,259	$ 7,824,023
2023	$ 2,580,562	2023	$ 1,493,544	$ 7,980,502
2024	$ 2,632,174	2024	$ 1,523,415	$ 8,140,113
2025	$ 2,684,817	2025	$ 1,553,883	$ 8,302,915
2026	$ 2,738,513	2026	$ 1,584,961	$ 8,468,973
2027	$ -	2027	$ -	$ -
2028	$ -	2028	$ -	$ -

NRG Dunkirk Repowering Project

Economic Impact Analysis

Final Report

Prepared for NRG Energy

by

Longwood Energy Group

March 20, 2013

Disclaimer

This report has been prepared for NRG Energy by Longwood Energy Group LLC, Newton Energy Group, Cambridge Energy Solutions, and Economic Development Research Group (together, the "LEG Team") on terms specifically limiting the liability of the LEG Team. Any opinion expressed herein shall not amount to any form of guarantee that the LEG Team has determined or predicted future events or circumstances, and no such reliance may be inferred or implied. This report shall not be construed as providing legal or financial opinions or guidance. To the extent the information in this report is to be used to make legal or financial determinations, you should seek advice from your own legal counsel and/or financial advisors.

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Summary

Longwood Energy Group (LEG), leading a team that includes Cambridge Energy Solutions, Newton Energy Group, and Economic Development Research Group, analyzed the impact of the Dunkirk repowering project on the New York wholesale electricity market and the New York State economy. This report presents the results of the study.

NRG Energy has proposed to repower the 540 MW Dunkirk coal-fired plant in western New York State with a 440 MW combined cycle gas turbine (CCGT) by mid-2017. This project, first proposed in 2011, offers a number of tangible economic benefits to the people of New York, including electricity ratepayers, other consumers, and citizens at large. As an added benefit the plant provides specific environmental benefits to the region by dramatically reducing air emissions.

The LEG analysis found that, among other benefits, repowering the plant with a CCGT will reduce the wholesale cost of electricity in the region and state—savings that can be passed along to ratepayers by their utilities. Over the 10 years covered by the analysis, repowering the plant—as opposed to retiring it—is projected to decrease wholesale electric energy prices by an average of $1.11/MWh. The decrease in wholesale energy prices is even more pronounced in the vicinity of Dunkirk: $2.35/MWh. This will stimulate the state's economy in virtually all sectors, generating jobs and economic activity, and increasing the gross state product. In addition, during the three years of construction, the project will directly create hundreds of well-paying jobs and associated economic benefits. By decreasing the cost of power produced in New York, this project will increase the likelihood that the power used by New Yorkers is produced within the state, for the benefit of its people and labor force.

The Dunkirk CCGT plant will provide enough power to supply approximately 11 percent of the projected 2018 demand in western New York and about two percent of total projected 2018 demand for New York State. This additional supply will reduce the need for generation from other power plants that would have higher pollutant emissions and operating costs. It would also help eliminate the need for expensive, long-distance transmission projects that provide little or no long-term economic benefits.

The LEG analysis projected wholesale power prices for three representative years over a 10-year period, for scenarios with and without the repowered Dunkirk plant in service, quantifying the expected reduction in wholesale power prices and wholesale electricity costs, as well as production costs and emissions that would result from the power supplied by the project. Additionally, the projected wholesale power cost reductions and expected expenditures on construction, operations, and maintenance (O&M) for the repowered plant were used to project the benefits to the regional and state economies.[1]

- **Repowering Dunkirk, as opposed to retiring it, will reduce the annual wholesale cost of electric energy for New York consumers by $142 million** on average over a 10-year period, saving over $1.4 billion in total over the period. Of this amount, $45 million per year, and over $455 million over the entire period, will accrue to ratepayers in the vicinity of Dunkirk.
  - The repowered plant will lower the price of electricity in the New York wholesale market by $1.11 on average over 10 years.
  - Reliance on out-of-state generation will also be reduced with a savings for the state of $39 million annually.
- **The project will deliver additional savings in wholesale costs of installed capacity of $159 million per year and nearly $1.6 billion over a 10-year period**. It will also produce savings in the wholesale costs of installed capacity in the vicinity of Dunkirk of approximately $42 million per year, or $417 million over the same 10-year period.
  - The price of installed capacity will be reduced, on average, by $0.89/kW-year for summers over the same period; winter installed capacity prices will be reduced by $0.78/kW-year on average.
- **Combined, energy and capacity cost savings will exceed $300 million per year, over $3 billion in total**.

[1] The prices, costs, and savings presented in this report are in today's dollars.

- **The project will increase the gross state product over the same period of operations an average of $348 million per year,** of which $136 million would accrue in the vicinity of Dunkirk. Significant economic benefits also accrue in the three-year construction period beginning in 2014.
- **During the construction phase, the project will generate over 300 jobs per year**, most of which will be in the vicinity of Dunkirk. **Once the plant begins operations, it will generate on average over 3,540 jobs per year**, of which about 1,390 would be in the vicinity of Dunkirk.
- The project will reduce the emissions of New York State's power production considerably because the Dunkirk CCGT will displace operation of the state's most inefficient generators. **Building the new Dunkirk plant will decrease New York generators' aggregate annual SOx emissions by as much as 6 percent, NOx by as much as 4.5 percent, and CO2 by as much as 1.3 percent.**

	Dunkirk Region (Zones A & B)	Total New York State
Energy Cost Savings		
Annual	$45 million/year	$142 million/year
10-Year Total	$455 million	$1.4 billion
Capacity Cost Savings		
Annual	$42 million/year	$159 million/year
10-Year Total	$417 million	$1.6 billion
Macroeconomic Benefits		
Gross Regional Product, 10 Years Operations	+ $136 million/year	+ $348 million/year
Total Jobs During Construction[2]	+ 248 on average	+ 308 on average
Total Jobs During 10 Years Operations[3]	+ 1,390/year on average	+ 3,540/year on average

[2] Average increase in jobs (direct, indirect, and induced) resulting from construction spending from 2014-2017; does not include jobs added due to O&M spending.
[3] Average increase in jobs (direct, indirect, and induced) resulting from ratepayer benefits and O&M spending from 2018-2027.

Approach

Electric power in New York State is bought and sold through a competitive wholesale market. The New York wholesale electricity market is operated by NYISO, the New York Independent System Operator, which is responsible for reliably managing and maintaining the flow of electricity across the State's power grid. New York utilities and other load-serving entities own and operate almost no generating capacity, but instead purchase wholesale power on the competitive market, the costs of which are ultimately recovered through the retail rates charged to end-use customers, referred to as ratepayers. Most electricity customers in New York pay regulated retail rates closely tied to expected wholesale power costs, which are therefore a good measure of electricity costs for New York ratepayers.

Wholesale power costs include two principal components: energy costs and capacity costs. Energy is the cost of actual delivered electricity. Capacity costs are payments made to generators to ensure that there is always enough generating capability or "installed capacity" to support the demand, or "load," plus a reserve margin. This is because generators' energy market revenues alone are insufficient to cover costs. The price of energy is determined on the NYISO spot (day-ahead and real-time) market, which reacts to immediate needs, while the market price of capacity is determined in periodic, longer-term auctions run by the NYISO.

The LEG analysis estimated the savings from repowering Dunkirk by projecting the energy and capacity components of wholesale power costs for the state with and without the Dunkirk CCGT in service. The analysis also estimated the production cost savings, and the impact on the cost of power flowing between New York and its neighbors. Finally, the projected energy and capacity cost savings, along with projected construction and O&M spending, were used to project the benefits of repowering Dunkirk to the regional economy, in terms of gross regional product and jobs created.

Energy cost and emissions reduction analysis

The power produced by the Dunkirk CCGT is expected to lower prices by displacing higher-cost generation. The plant is also expected to reduce emissions because its modern, efficient generation will displace higher-emission generation.

As in other coordinated power markets, power in New York is priced hourly and by location, with the market price set by the offer from the most expensive generating facility needed to meet demand. The repowering project's impact on prices and emissions can be analyzed by comparing two future possibilities: one in which the existing Dunkirk coal plant is replaced by a new combined cycle plant, and the other in which Dunkirk is retired.[4] In each hour that the prices in a scenario with Dunkirk repowered are lower than the prices in a scenario with Dunkirk retired, electricity costs will be reduced.

The variable operating cost of the repowered Dunkirk plant, largely determined by its high efficiency and the low cost of natural gas, will be competitive relative to existing generation resources, and the plant's electricity will be offered at a price that reflects that low cost. As a result, the new Dunkirk plant will displace higher-cost generation and the associated emissions in most hours of the year, resulting in a lower market price and reduced total emissions by the generating fleet.

The analysis estimated these price decreases and emission decreases for each hour of each of three representative years: 2018, 2020, and 2025. By interpolating the results for intervening years and extrapolating the 2025 results for 2026-2027, the analysis projected reductions for each year from 2018 through 2027.[5]

---

[4] Because Dunkirk serves certain reliability needs, the modeled scenario in which Dunkirk is retired must include certain transmission upgrades needed to address those same needs in the absence of Dunkirk. In the repowering scenario, it is assumed that one peaking unit at Dunkirk remains in place for reliability purposes until the repowering is complete. Certain upgrades determined by National Grid to be necessary during the continued operation of the existing Dunkirk plant are assumed to be in place in both scenarios.

[5] The plant is expected to enter service in mid-2017. The simulation results presented in this section begin with the first full year of operation (2018), although results for 2017 were included as inputs to the macroeconomic analysis.

The projections rely on publicly available data, including the following key input assumptions:

Fuel prices. Natural gas and oil prices are based on regional monthly forward curves published by SNL Financial, and the Energy Information Administration (EIA) Annual Energy Outlook (AEO) 2013, early release issued December 2012.[6] The SNL forecast through 2019 is used, after which annual increases in the EIA forecast are used to calculate subsequent monthly values from the SNL forecast for 2019.

Demand growth. Electricity demand growth assumptions are as projected by NYISO in its *2012 Load & Capacity Data*, Version 3, released in April 2012. Because NYISO projects load growth only through 2022, the analysis assumes annual demand growth for subsequent years to remain constant at 2021-2022 levels.

Generation additions and retirements. Future thermal generation units are added to meet regional capacity requirements, and future renewable generation (predominantly wind) is added from the NYISO Interconnection Queue to meet the New York state renewable portfolio standard (excluding newly proposed solar energy requirements). The analysis uses NYISO data on announced retirements.[7]

Emission permit prices. The analysis uses emission permit prices from the STARS (The U.S. EPA's "Science to Achieve Results") 2012 low emission prices scenario.

For impacts on wholesale electric energy prices, the analysis uses DAYZER, a detailed economic security-constrained dispatch and production-costing model for electricity networks developed by Cambridge Energy Solutions. The DAYZER model uses specified cost-based offers for each generator in the market, as well as a representation of New York's transmission system, to find the least-cost dispatch of power plants and calculate hourly prices for electricity for each location in the NYISO market. This process, equivalent to the one used by NYISO in its operation of the power system and wholesale market, was performed for each of the scenarios: with Dunkirk repowered, and with Dunkirk retired. In each hour, the total wholesale energy cost for each of the NYISO load zones is calculated as the product of the zonal location-based market price (LBMP) and the zonal load.

Capacity cost reduction analysis

Installed Capacity (ICAP) prices in the New York system are established for three locations (ICAP zones): New York City, Long Island and Rest of State. The Rest of State ICAP zone accounts for the requirements of load zones A through I and for approximately 17% of load served in Zone J (New York City). This analysis assumes that repowering Dunkirk will affect capacity prices only in the Rest of State.

Load serving entities 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. Prices in the spot auction are determined by the administratively set demand curve depicted in Figure 1 below.

As this figure shows, the spot auction price depends on the level of capacity available in that month, in terms of "unforced capacity" (UCAP), a measure of installed capacity adjusted to account for generation outages. When more capacity is

[6] http://www.eia.gov/forecasts/aeo/er/pdf/0383er(2013).pdf

[7] http://www.nyiso.com/public/markets_operations/services/planning/documents/index.jsp?docs=interconnection-studies/other-interconnection-documents. Additionally, Danskammer units 1-4 are assumed to retire.

added to the system, the capacity price declines as shown in Figure 2.

To assess the impact of the Dunkirk repowering on capacity prices and associated ratepayer costs, the LEG team first developed a forecast of the demand curve and then computed capacity prices under two scenarios: 1) with Dunkirk repowered and 2) with Dunkirk retired. The analysis estimates potential savings in capacity costs by multiplying the reduction in capacity prices observed in the repowering scenario by the installed capacity requirements in the Rest of State capacity zone. Of those savings, 25% were assumed to be unattainable by load-serving entities with long-term contracts at prices determined prior to (and therefore unaffected by) the capacity spot price reductions.

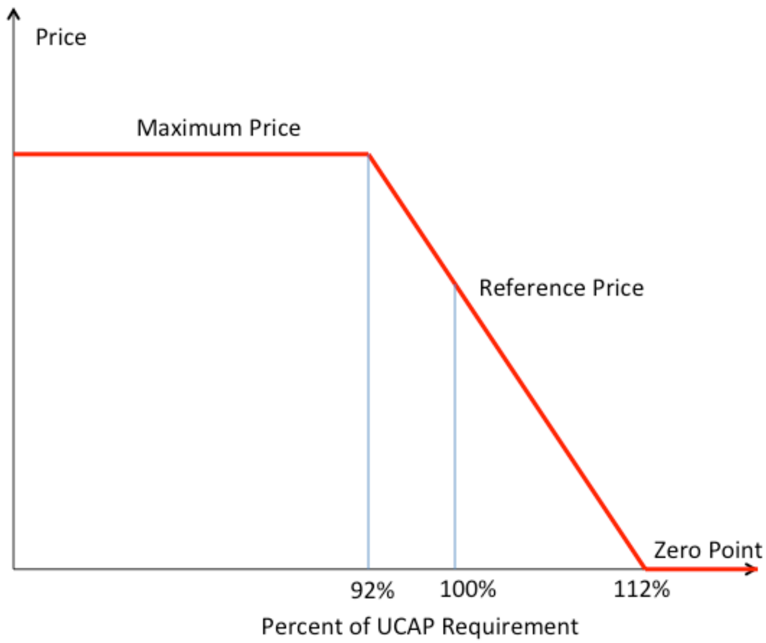

Figure 1. Capacity spot price formation mechanism

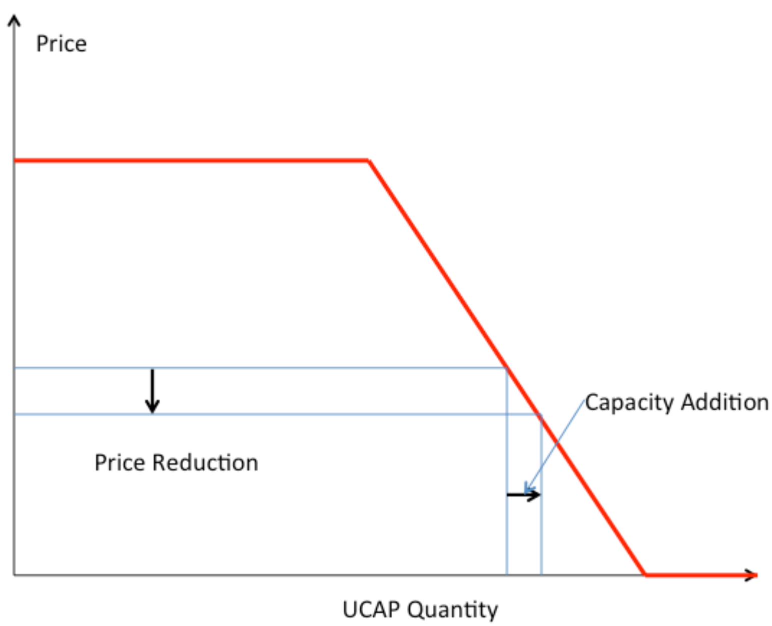

Figure 2. Impact of capacity addition on capacity price.

Macroeconomic analysis

The analysis uses PI+, a 23-sector model developed by Regional Economic Models, Inc., to project the economic impacts, relative to the base case, on gross state product or gross regional product (GRP), industry sales, and employment. These benefits reflect the direct effects of the repowering and the subsequent multiplier effects captured within the dynamically adjusting annual forecasting framework of the REMI system. The model was configured using a representation of three sub-regions: the western part of the state in the vicinity of Dunkirk, New York City and Long Island, and the remainder of the state.

Projected changes in wholesale electricity prices for 2017-2027 were allocated by customer segment, and along with short-term facility construction and on-going O&M spending, introduced into the REMI model.

The model generates annual estimates of the total impact (direct plus multiplier responses) by region, from any specific policy initiative (or infrastructure investment) compared to the base case—which in this case is Dunkirk retired and any transmission upgrades required in the absence of the repowered plant.

The repowering's benefits to the state's economy occur chiefly because of (i) the construction phase spending between 2014 into 2017, (ii) beginning mid-2017, the annual operations and maintenance (O&M) spending, and (iii) the ratepayer benefits due to reductions in the energy and capacity portions of the wholesale energy cost that result from a more efficient generating unit joining the generating fleet.

Construction and O&M cost assumptions

The following figures summarize the construction and O&M cost assumptions provided by NRG and used in the three-region REMI forecasting model. These within-region expenditures are considered to be *direct effects* for the scenario, and it is these (along with the direct effects of the electricity cost savings) that cause subsequent *economic multiplier effects*. The direct *plus* the multiplier effects define the *total impact* in a year for the metric of interest.

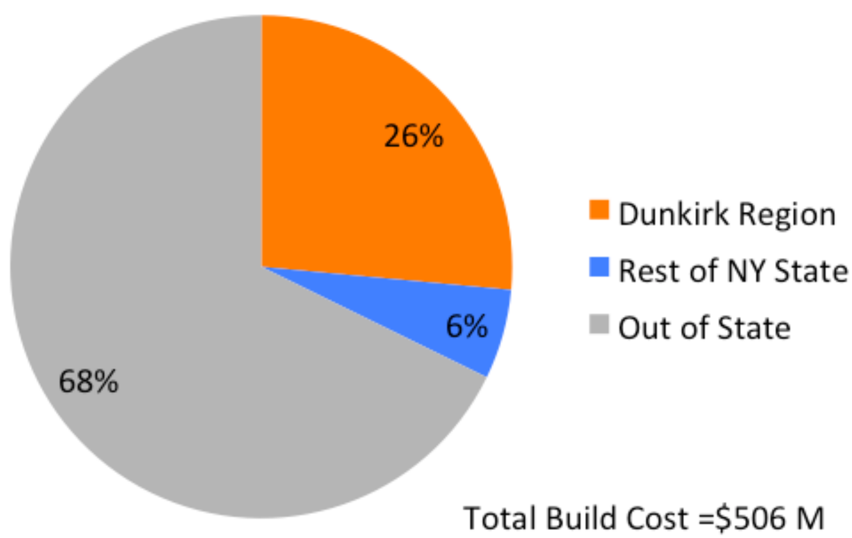

Figure 3. Allocation of construction budget by region (2012$).

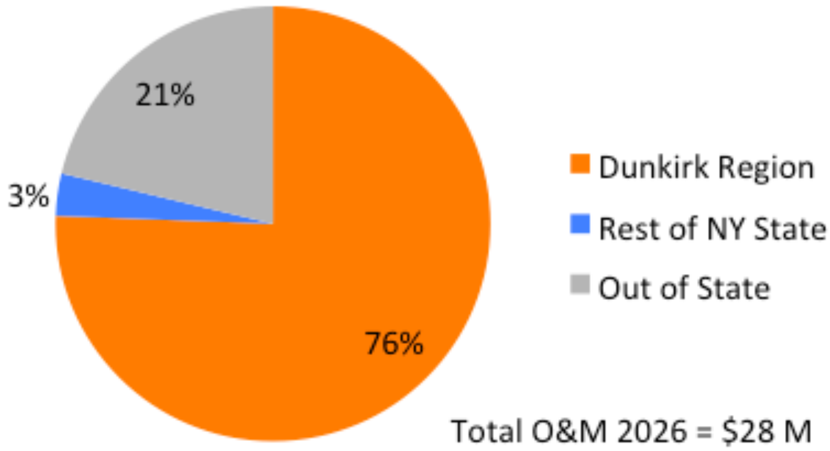

Figure 4. Allocation of Annual O&M requirements by region (2012$).

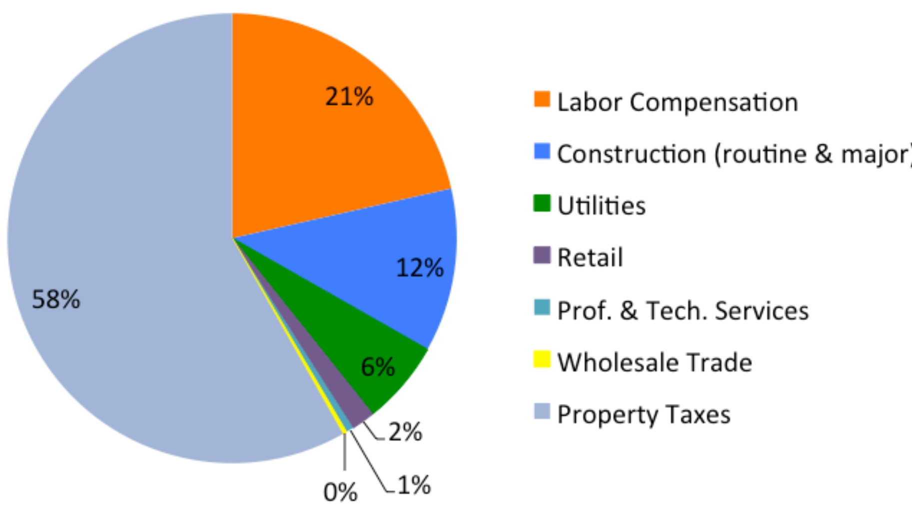

Figure 5. O&M spending by Industry for the Dunkirk region for 2026 (2012$).

Results

Energy price reductions

Figure 6 shows estimates of the decrease in the average New York wholesale power prices resulting from repowering Dunkirk, compared to retiring the plant. Over the 10 years covered by the analysis, wholesale energy prices would be an average of $1.11/MWh lower with the plant repowered than with it retired. The effect on wholesale electricity prices is even more pronounced for western New York, close to the generator, as shown in Figure 7. The average price reduction over the period for the region in the vicinity of Dunkirk is $2.35/MWh. [8]

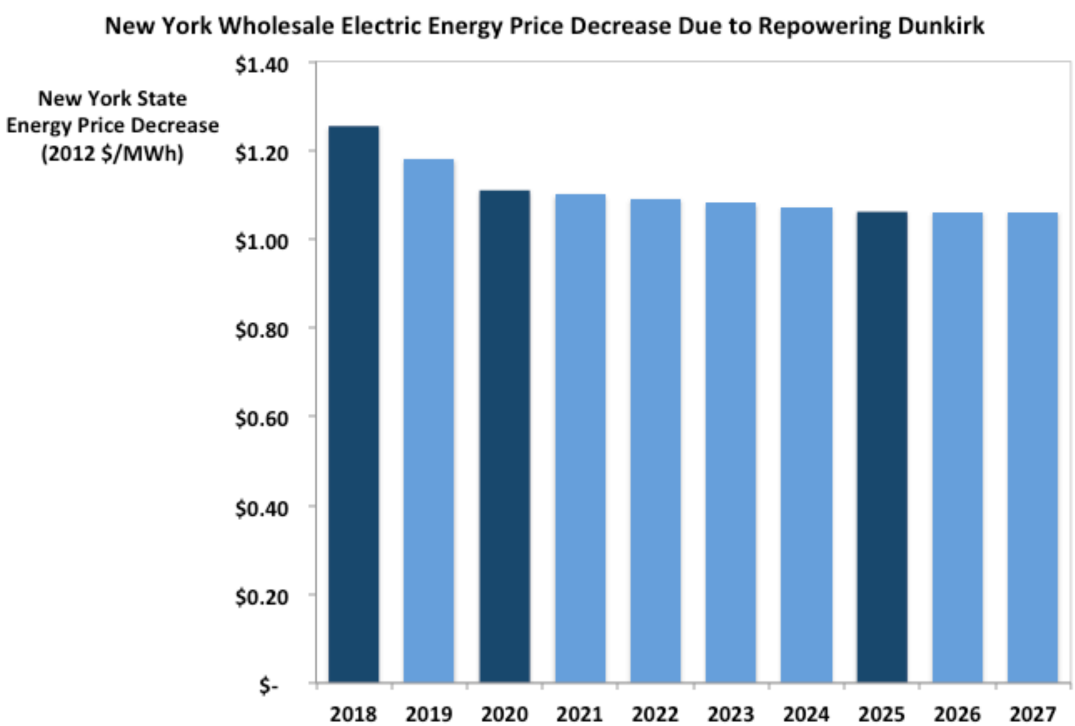

Figure 6. Impact of repowering Dunkirk on wholesale electricity (energy) prices. Simulated years are in dark blue.

[8] This region is defined here, for the purposes of the energy and capacity cost impact analysis, as NYISO load zones A and B. For the purposes of the macroeconomic analysis, the region is roughly the same, consisting of Chautauqua, Cattaraugus, Erie, Wayne, Livingston, Genesee, Niagara, Orleans, Allegany, Ontario, Monroe, and Wayne counties.

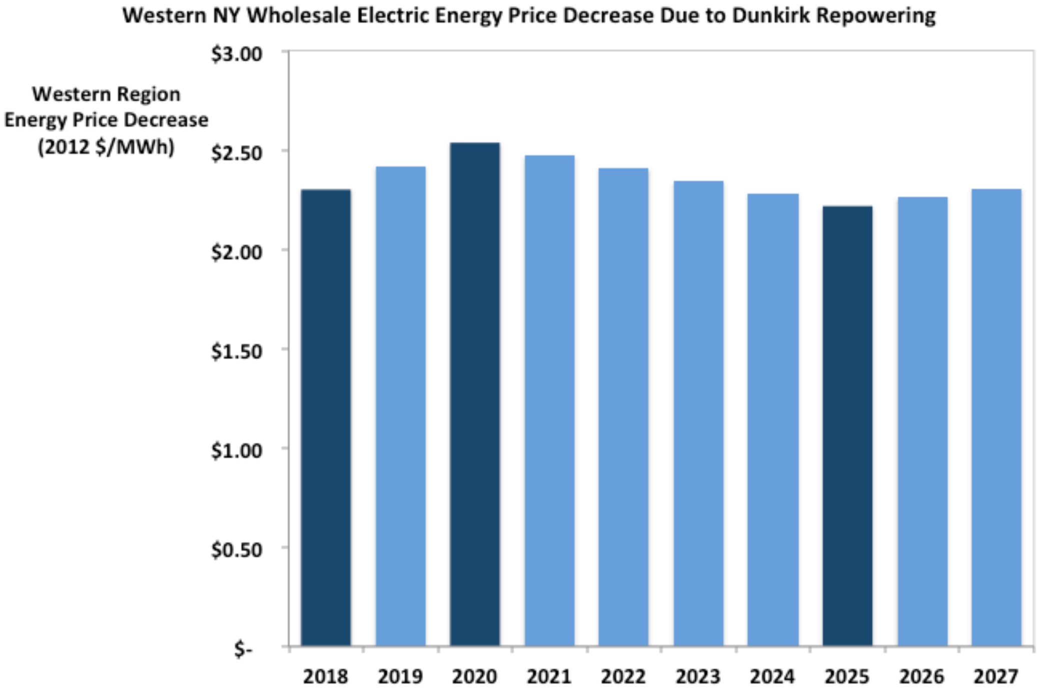

Figure 7. Impact of repowering Dunkirk on wholesale electric energy prices in the western New York / Dunkirk region. Simulated years are in dark blue.

Wholesale energy cost reductions

The expected savings in electricity costs associated with the forecasted reduction in wholesale energy market prices are shown in Figure 8. The cost savings in today's dollars range between $138 million and $158 million annually, totaling $1.4 billion over the 10-year period.[9] Of these, $45 million per year, or $455 million accrued to the western region of the state.[10] Savings differ across the three modeled years due to several factors, including the addition of wind generation between 2018 and 2020 to meet the RPS, the addition of new generating capacity added to meet regional demand growth, and changes in the difference between gas and coal prices. Moreover, the addition of the CCGT's output creates a surplus, which initially puts downward pressure on energy prices, which then rise as demand growth absorbs the surplus.

Another measure of societal impact and economic efficiency is production cost, which is generators' cost to produce the electricity (variable costs, predominatly fuel). The LEG analysis showed that repowering Dunkirk results in average production cost savings of $28 million/year, totalling $281 million over the 10-year analysis time horizon.[11]

Additionally, because of the project's impact on system prices and dispatch, the cost of energy purchased (and value of energy sold) across New York's borders with its neighbors will change, reflecting a reduced reliance on out-of-state

[9] A reduction of 25 percent in the projected savings is reflected in these totals to account for savings assumed to be unattainable by load-serving entities with long-term contracts at prices determined prior to (and therefore unaffected by) the energy price impacts.

[10] Zones A (West) and B (Genesee).

[11] Note that because the generation cost is a component of wholesale energy costs, the savings are not additive.

generators. The analysis showed the predominant impact to be a decrease in the cost of imports, with a net decrease of approximately $39 million per year, totalling over $394 million over the 2018-2027 period.[12]

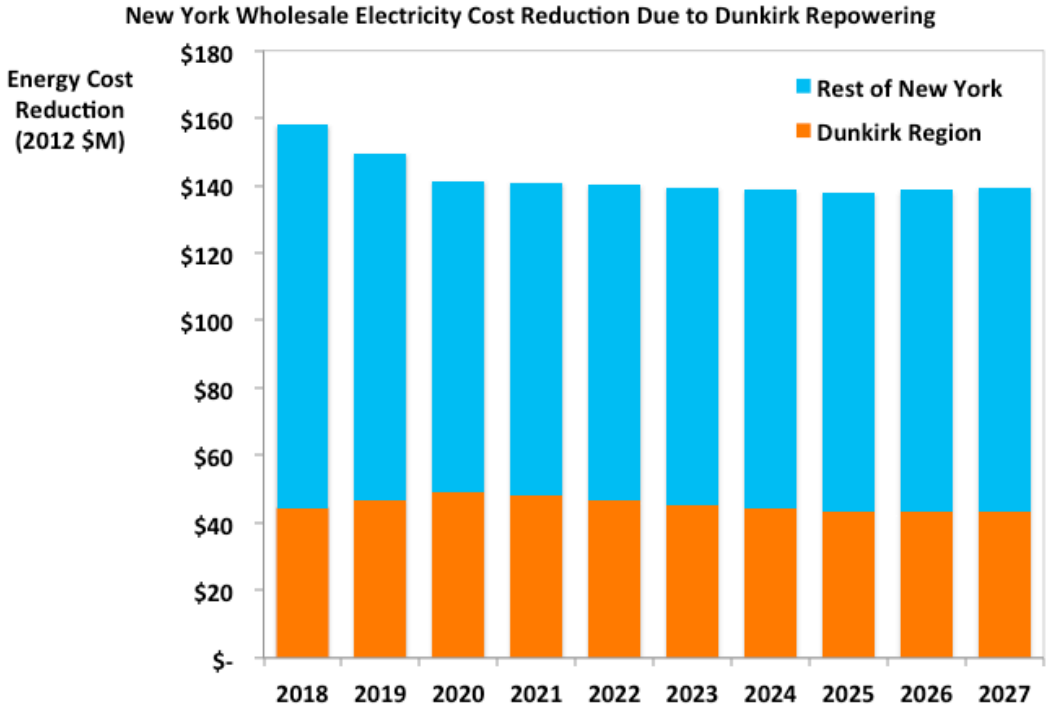

Figure 8. Impact of repowering Dunkirk on wholesale electric energy costs.

Capacity cost reductions

The impact of repowering Dunkirk on capacity prices in the Rest-of-State capacity region is shown in Figure 9 below. Repowering Dunkirk is estimated to reduce Rest-of-State summer capacity prices by approximately $0.89/kW-month on average with small variations around this number. The average reduction in Rest-of-State winter capacity prices is approximately $0.78/kW-month and varies over time between $0.27/kW-month and $0.93/kW-month.

Estimated annual state-wide capacity cost reductions through 2023 are presented in Figure 10 below. As in the energy cost analysis, the capacity analysis assumes that only 75% of the modeled capacity price impact will be realized by load-serving entities and the consumers they serve; the cost savings listed here and shown in Figure 10 account for the assumed 25% reduction in impact.

Statewide savings in wholesale costs of installed capacity amount to $159 million per year (in today's dollars), or nearly $1.6 billion over the 10 years from 2018 through 2027. Savings in the wholesale costs of installed capacity for the two load zones in the vicinity of Dunkirk (zones A and B) are estimated at $42 million per year, or approximately $417 million over the same 10-year period.

[12] Price decreases at New York's borders caused by the repowering reduce the cost of imports (predominantly) and the revenues associated with exports, with a net cost decrease overall. Because this analysis includes the simplifying assumption that cross-border flows were unaffected by the repowering project, the effects of the repowering and associated price changes on import and export quantities are not accounted for.

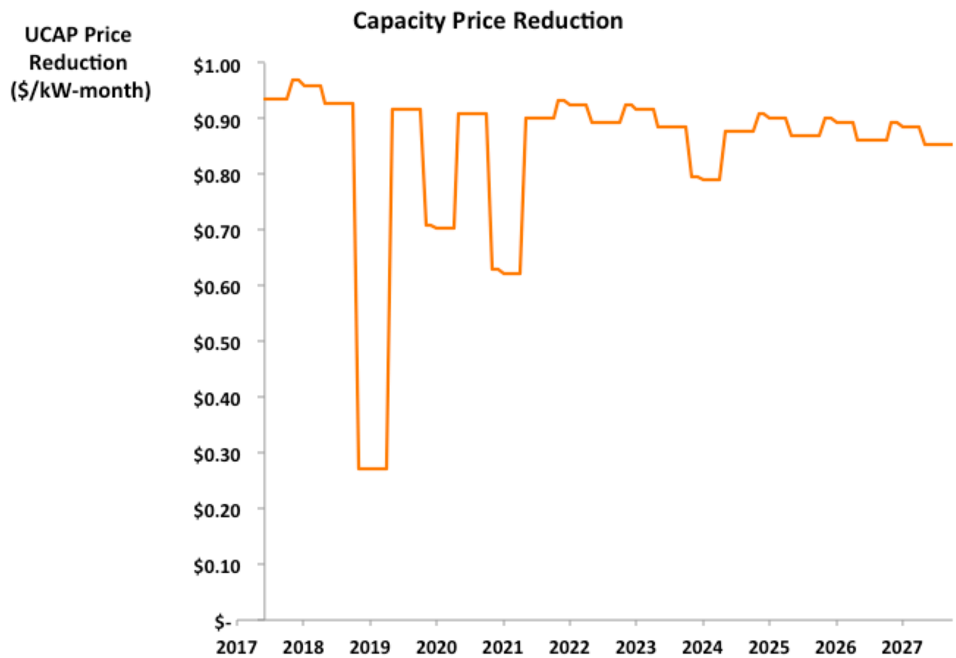

Figure 9. Capacity price reductions in Rest-of-State zone with Dunkirk repowered (2012$).

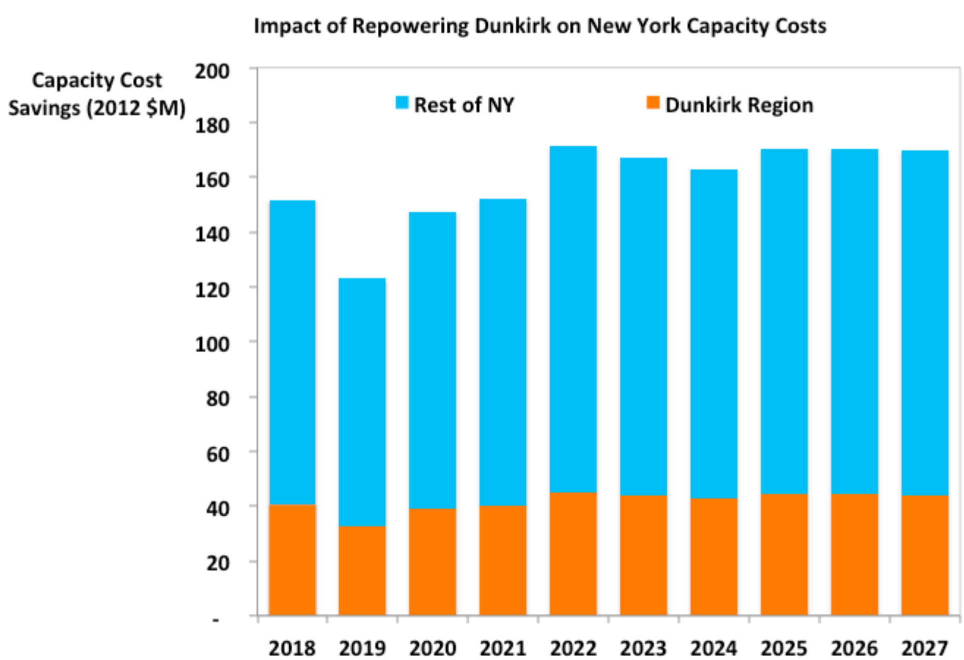

Figure 10. Estimated annual capacity cost reduction.

Emissions reductions

The projected reductions in the emissions of New York's generating fleet due to the Dunkirk repowering are shown in Figure 11. The annual reduction in CO_2 emissions ranges between 0.5 and 1.3 percent, averaging 0.8 percent and totaling 2.6 million metric tons over the 10-year period. Statewide annual NOx emissions are reduced between 2.4 and 4.5 percent, averaging 3.2 percent and totalling over 5,000 metric tons over the 10-year period. Annual SOx emissions are reduced between 2.1 and 6 percent, averaging 3.5 percent and totalling over 4,800 metric tons.

The statewide emissions reductions due to the Dunkirk repowering vary across the three modeled years primarily due to the changing generation mix over the time period. That is, as the supply mix shifts toward more efficient natural gas fired plants and renewables, the reduction attributable to Dunkirk decreases.

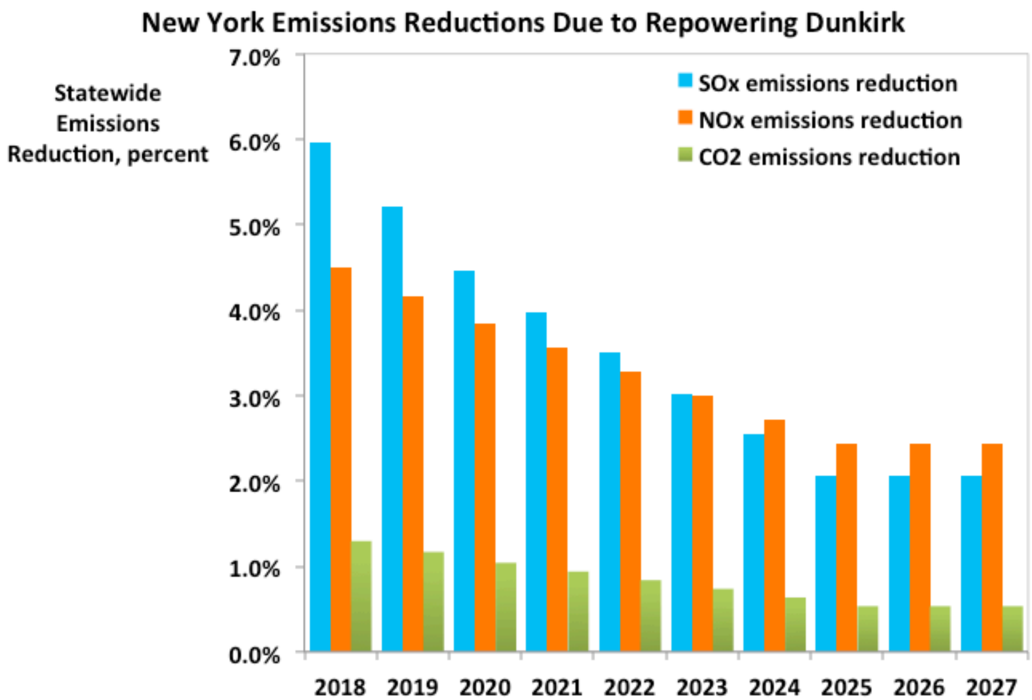

Figure 11. Statewide emissions reductions resulting from repowering Dunkirk.

Benefits to the regional economy

Repowering Dunkirk will create jobs in three ways:

Direct jobs, created at firms involved with the project

Indirect jobs, created at firms that provide goods and services used by the firms involved directly in the project

Induced jobs, created elsewhere in the economy as increases in income from the construction spending, O&M spending, and ratepayer benefits lead to additional increases in spending by workers and firms

Figure 12 shows that repowering Dunkirk will create thousands of jobs in New York State and in the sub-region around Dunkirk, relative to the base case.[13] Over the period illustrated by the figure, the regional economy in the plant's vicinity will add on average 1,200 jobs, as a result of involvement in the project's construction phase, a key role in fulfilling ongoing O&M activities, and its ratepayers (in all customer-segments) benefiting from lower rates. Statewide, the resulting benefit averages more than 2,850 jobs over the period, and over 3,540 per year over 10 years of operations, of which about 1,390 are in the vicinity of Dunkirk. These impacts are predominantly due to reductions in electricity costs, as the customer savings exert a beneficial influence on the economy.

[13] Again, this sub-region in the vicinity of Dunkirk corresponds approximately to NYISO load zones A and B.

Figure 13 presents the forecast of impacts by region based on dollars of gross state and regional product, effectively the value added. Not surprisingly, the pattern is similar to that observed for employment impact, with a 10-year average statewide impact of nearly $350 million per year (2012$), of which $136 million are seen in the region around Dunkirk.

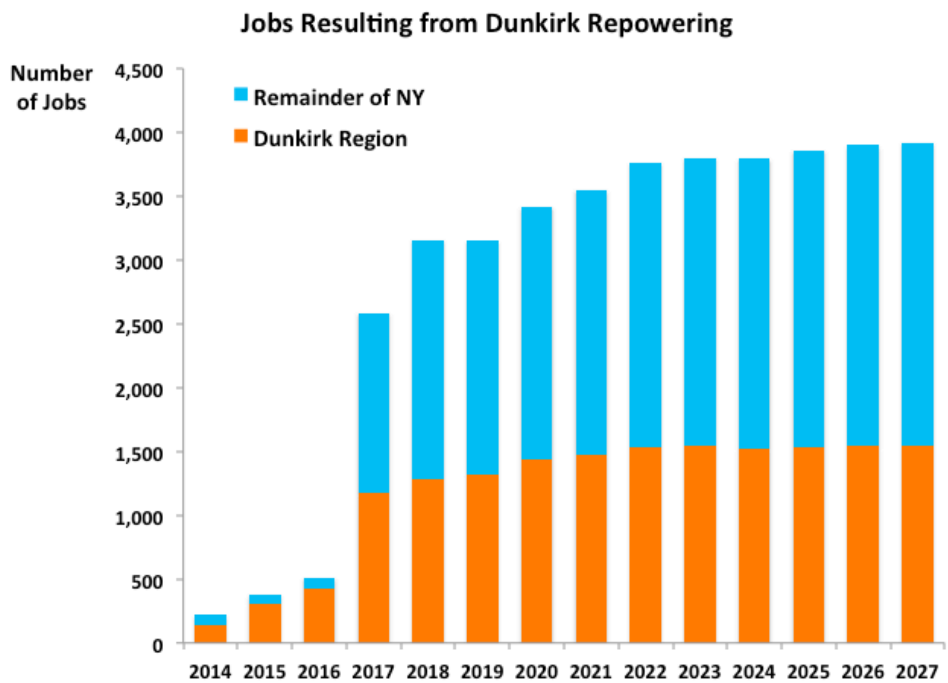

Figure 12. Projected annual impact on jobs.

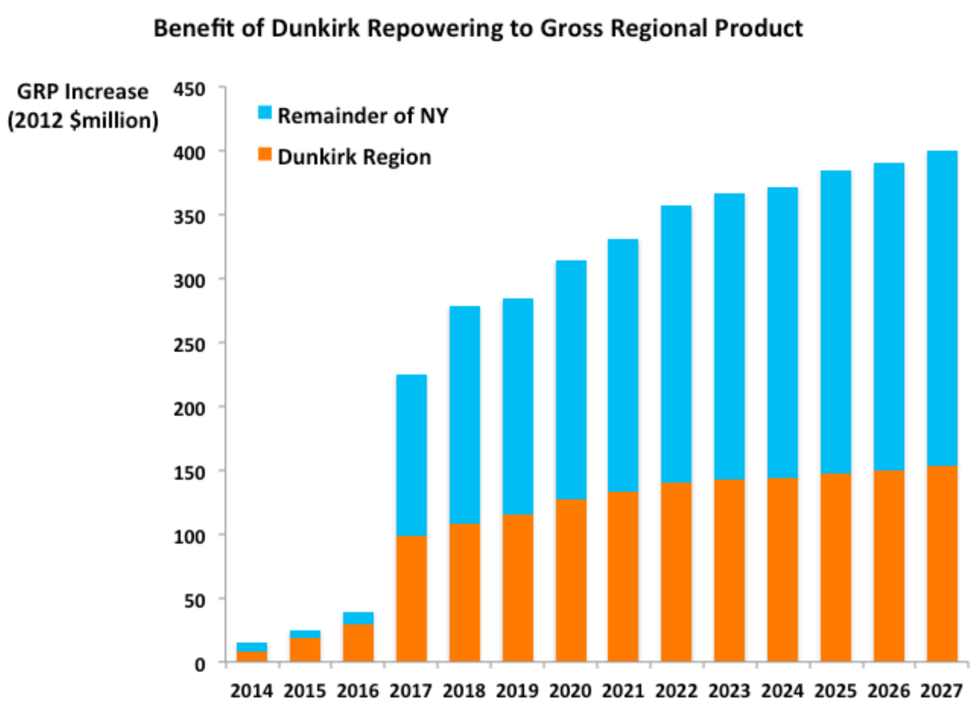

Figure 13. Projected annual impact on gross regional product.

The average annual GRP impact and job additions for the construction period and 10 years of operations are summarized in Table 1. Table 2 illustrates the cumulative benefits over 10 years, focusing on the effect of O&M spending and ratepayer benefits. As the table shows, over the 10-year timeframe, the persistence and the scale of ratepayer benefits associated with the repowered plant are responsible for bolstering the regional economies the most.

TABLE 1. AVERAGE ANNUAL ECONOMIC BENEFITS OF REPOWERING DUNKIRK

	Dunkirk Region (Zones A & B)	Total New York State
Macroeconomic Benefits		
Gross Regional Product, 10 Years Operations	+ $136 million/year	+ $348 million/year
Total Jobs During Construction[14]	+ 248 on average	+ 308 on average
Total Jobs During 10 Years Operations[15]	+ 1,390/year on average	+ 3,540/year on average

TABLE 2. CUMULATIVE ECONOMIC BENEFITS, 10 YEARS OF OPERATION

	Dunkirk Region (Zones A & B)	Total New York State
Cumulative Increase In Gross Regional Product (2012$), 2018-2027		
O&M Spending	+ $393 million	+ $413 million
Ratepayer Benefit	+ $968 million	+ $3.1 billion
Total	+ $1.4 billion	+ $3.5 billion
Cumulative Job Years, 2018-2027		
O&M Spending	+ 3,020	+ 3,160
Ratepayer Benefit	+ 10,900	+ 32,300
Total	+ 13,900	+ 35,400

Figure 14 profiles the distribution of job impacts by industry in 2022 (when ratepayer benefit is at a maximum). This provides insight into which industries, as electricity consumers, become more competitive as a result of lower outlays on electricity purchases, reducing these industries' relative cost of doing business and allowing for market share growth in local and/or export markets. A part of these industry-specific job gains is also attributable to increased consumer spending when households spend less on electricity. The pronounced job impact in health care services and retail activities points to higher spending by existing households due to their lower electricity bills. The pronounced increase in state and local government jobs is the result of a projected increase in regional population that the REMI model captures when the employment opportunities increase, and when the cost of living moderates to make gains in real income. Both of these effects signal inward economic migration of the working age cohorts. When this happens, the labor force expands, putting downward pressure on the labor input cost to employers in New York state, also facilitating market share growth on top of the impact of reduced electricity costs in the commercial and industrial segments. Part of the construction sector's job increase is explained by stimulated economic activity in each of these regions, which signals the need for more buildings, and other physical plant.

[14] Average increase in jobs (direct, indirect, and induced) resulting from construction spending from 2014-2017; does not include jobs added due to O&M spending.
[15] Average increase in jobs (direct, indirect, and induced) resulting from ratepayer benefits and O&M spending from 2018-2027.

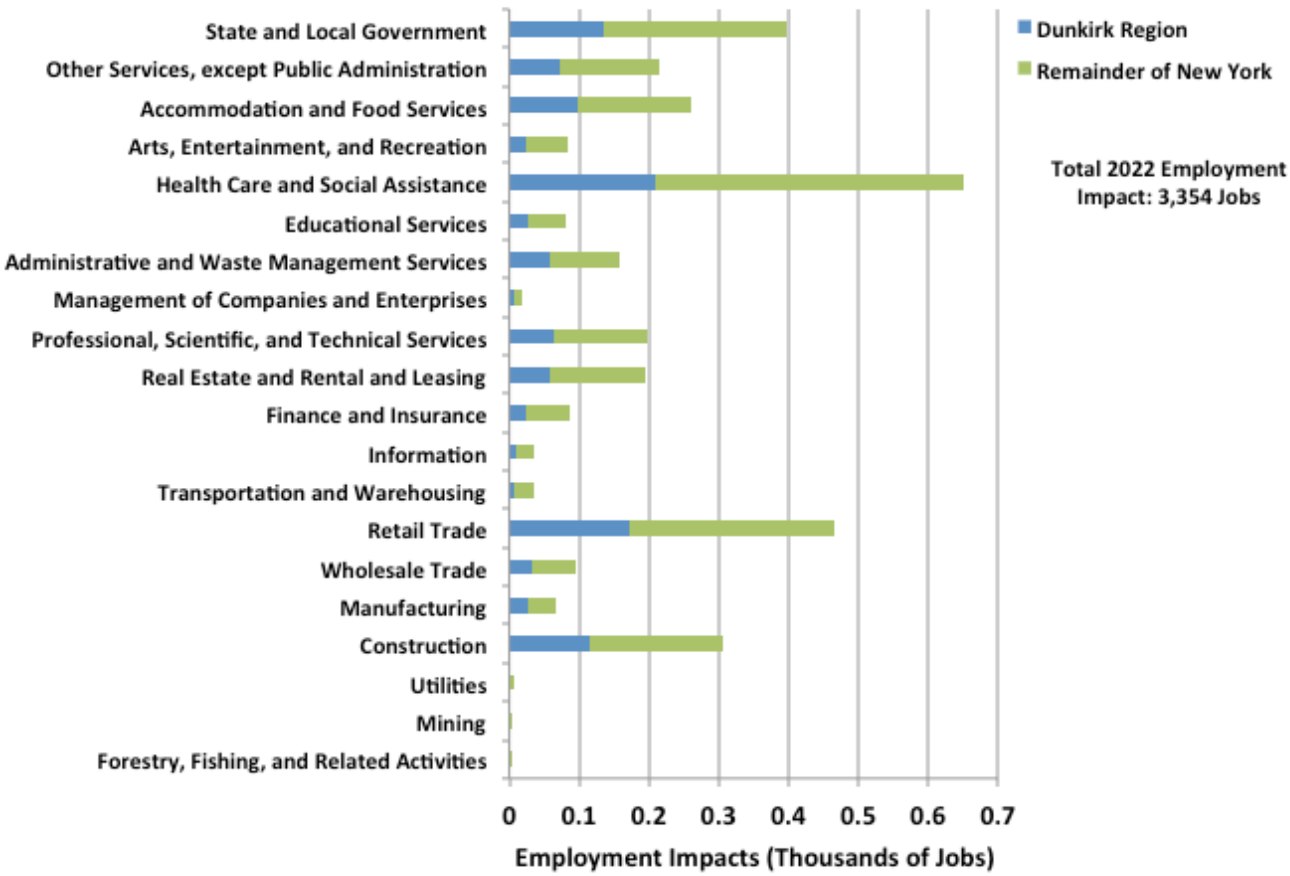

Figure 14. Jobs resulting from the ratepayer benefit, by region and industry, for 2022, the year of maximum impact.

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DUNKIRK REPOWERING
1X1 CCGT
CONCEPTUAL ONE-LINE DIAGRAM

ESK-1x1-001, Rev. A 12Apr13

Attachment E to NRG Energy, Inc.
Response to NMPC - 12

[redacted]

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Attachment F to NRG Energy, Inc.
Response to NMPC-15 and NMPC-16

	Henry Hub Price ($/mmBtu)	TETCO M3 Delivered Basis	Delivered Cost ($/mmBtu)
5/1/2013	$ 4.09	$ 0.15	**$ 4.24**
6/1/2013	$ 4.13	$ 0.16	**$ 4.29**
7/1/2013	$ 4.17	$ 0.21	**$ 4.38**
8/1/2013	$ 4.19	$ 0.20	**$ 4.39**
9/1/2013	$ 4.18	$ 0.11	**$ 4.28**
10/1/2013	$ 4.18	$ 0.12	**$ 4.30**
11/1/2013	$ 4.24	$ 0.17	**$ 4.41**
12/1/2013	$ 4.38	$ 0.41	**$ 4.79**
1/1/2014	$ 4.46	$ 0.80	**$ 5.26**
2/1/2014	$ 4.43	$ 0.61	**$ 5.04**
3/1/2014	$ 4.37	$ 0.16	**$ 4.53**
4/1/2014	$ 4.05	$ 0.10	**$ 4.15**
5/1/2014	$ 4.05	$ 0.05	**$ 4.10**
6/1/2014	$ 4.07	$ 0.07	**$ 4.13**
7/1/2014	$ 4.10	$ 0.10	**$ 4.19**
8/1/2014	$ 4.11	$ 0.10	**$ 4.21**
9/1/2014	$ 4.11	$ 0.02	**$ 4.13**
10/1/2014	$ 4.13	$ 0.03	**$ 4.16**
11/1/2014	$ 4.20	$ 0.12	**$ 4.32**
12/1/2014	$ 4.37	$ 0.30	**$ 4.67**
1/1/2015	$ 4.46	$ 0.53	**$ 4.98**
2/1/2015	$ 4.44	$ 0.45	**$ 4.89**
3/1/2015	$ 4.36	$ 0.13	**$ 4.49**
4/1/2015	$ 4.04	$ 0.07	**$ 4.11**
5/1/2015	$ 4.05	$ 0.07	**$ 4.12**
6/1/2015	$ 4.07	$ 0.07	**$ 4.14**
7/1/2015	$ 4.11	$ 0.06	**$ 4.17**
8/1/2015	$ 4.12	$ 0.06	**$ 4.19**
9/1/2015	$ 4.13	$ 0.06	**$ 4.19**
10/1/2015	$ 4.16	$ 0.06	**$ 4.22**
11/1/2015	$ 4.23	$ 0.12	**$ 4.35**
12/1/2015	$ 4.40	$ 0.30	**$ 4.70**
1/1/2016	$ 4.50	$ 0.53	**$ 5.02**
2/1/2016	$ 4.47	$ 0.45	**$ 4.92**
3/1/2016	$ 4.39	$ 0.13	**$ 4.52**
4/1/2016	$ 4.07	$ 0.05	**$ 4.12**
5/1/2016	$ 4.08	$ 0.05	**$ 4.13**
6/1/2016	$ 4.11	$ 0.05	**$ 4.16**
7/1/2016	$ 4.14	$ 0.05	**$ 4.19**
8/1/2016	$ 4.16	$ 0.05	**$ 4.21**
9/1/2016	$ 4.17	$ 0.05	**$ 4.22**
10/1/2016	$ 4.20	$ 0.05	**$ 4.25**
11/1/2016	$ 4.29	$ 0.11	**$ 4.40**
12/1/2016	$ 4.48	$ 0.28	**$ 4.76**
1/1/2017	$ 4.57	$ 0.50	**$ 5.07**
2/1/2017	$ 4.55	$ 0.42	**$ 4.97**
3/1/2017	$ 4.47	$ 0.12	**$ 4.59**
4/1/2017	$ 4.14	$ 0.04	**$ 4.17**
5/1/2017	$ 4.15	$ 0.04	**$ 4.19**

6/1/2017	$	4.18	$	0.04	**$**	**4.21**
7/1/2017	$	4.21	$	0.04	**$**	**4.25**
8/1/2017	$	4.23	$	0.04	**$**	**4.27**
9/1/2017	$	4.23	$	0.04	**$**	**4.27**
10/1/2017	$	4.27	$	0.04	**$**	**4.30**
11/1/2017	$	4.37	$	0.11	**$**	**4.48**
12/1/2017	$	4.57	$	0.28	**$**	**4.85**
1/1/2018	$	4.67	$	0.50	**$**	**5.17**
2/1/2018	$	4.65	$	0.42	**$**	**5.07**
3/1/2018	$	4.57	$	0.12	**$**	**4.69**
4/1/2018	$	4.22	$	0.03	**$**	**4.25**
5/1/2018	$	4.24	$	0.03	**$**	**4.26**
6/1/2018	$	4.27	$	0.03	**$**	**4.29**
7/1/2018	$	4.30	$	0.04	**$**	**4.34**
8/1/2018	$	4.32	$	0.04	**$**	**4.36**
9/1/2018	$	4.33	$	0.03	**$**	**4.35**
10/1/2018	$	4.36	$	0.03	**$**	**4.39**
11/1/2018	$	4.48	$	0.11	**$**	**4.59**
12/1/2018	$	4.69	$	0.29	**$**	**4.98**
1/1/2019	$	4.80	$	0.30	**$**	**5.10**
2/1/2019	$	4.78	$	0.28	**$**	**5.06**
3/1/2019	$	4.70	$	0.14	**$**	**4.85**
4/1/2019	$	4.41	$	0.08	**$**	**4.49**
5/1/2019	$	4.43	$	0.06	**$**	**4.49**
6/1/2019	$	4.46	$	0.07	**$**	**4.53**
7/1/2019	$	4.50	$	0.09	**$**	**4.59**
8/1/2019	$	4.52	$	0.09	**$**	**4.61**
9/1/2019	$	4.53	$	0.06	**$**	**4.59**
10/1/2019	$	4.56	$	0.07	**$**	**4.63**
11/1/2019	$	4.68	$	0.20	**$**	**4.88**
12/1/2019	$	4.90	$	0.20	**$**	**5.10**
1/1/2020	$	5.02	$	0.30	**$**	**5.32**
2/1/2020	$	5.01	$	0.28	**$**	**5.28**
3/1/2020	$	4.93	$	0.14	**$**	**5.07**
4/1/2020	$	4.65	$	0.08	**$**	**4.73**
5/1/2020	$	4.67	$	0.06	**$**	**4.73**
6/1/2020	$	4.70	$	0.07	**$**	**4.76**
7/1/2020	$	4.74	$	0.09	**$**	**4.83**
8/1/2020	$	4.76	$	0.09	**$**	**4.86**
9/1/2020	$	4.77	$	0.06	**$**	**4.83**
10/1/2020	$	4.81	$	0.07	**$**	**4.88**
11/1/2020	$	4.93	$	0.20	**$**	**5.13**
12/1/2020	$	5.15	$	0.20	**$**	**5.35**

Request Date: April 1, 2013 Request No. NMPC-15
Due Date: April 15, 2013

Case No. 12-E-0577 – Proceeding on Motion of the Commission to Examine Repowering Alternatives to Utility Transmission Reinforcements

Request for Information

From: Niagara Mohawk Power Corporation d/b/a National Grid
To: NRG Energy, Inc.

Request: Natural Gas Costs (Option 1)

Attachment A indicates that for the CCGT portion of the proposal:
"Buyer will purchase and arrange delivery of natural gas to the CCGT project."

a) Please list all categories of costs NRG anticipates a buyer would incur to "purchase and arrange delivery of natural gas to the CCGT project."
b) Please provide all costs, estimates, forecasts, projections, etc., for each category of cost identified in response to (a), for each year of the proposed term.
c) Please provide all estimates, forecasts, projections, etc., of natural gas volumes the buyer would be responsible to purchase and arrange delivery of for each year of the proposed term.
d) Please describe the form of tolling agreement for the CCGT portion of the proposal.
   i. List and describe all items and/or services that would be included in the proposed tolling agreement.
   ii. List and describe all items and/or services that would be excluded from the proposed tolling agreement that would be the buyer's responsibility to procure. What is NRG's estimate of the costs for NRG Power Marketing Services Group to provide those items and/or services that are excluded from the proposed tolling agreement?

Response:

a) The following categories should be included in the delivered cost of natural gas to a power production facility:

- **Commodity** – Cost of the natural gas commodity
- **Transportation** – Variable Cost (commodity fees and fuel) associated with moving gas through the pipeline network from a liquid delivery point to the facility burner tip
- **Taxes** – any applicable sales, use or gross receipts tax that may be assessed. It is NRG's understanding natural gas used in the production process (i.e. electricity generation) is exempt from New York State sales tax.
- **Balancing** – Cost for the capability to balance inter-day gas needs

[redacted]

Name of Respondent:

Jonathan Baylor

Date of Reply:

April 15, 2013

Request Date: April 1, 2013 Request No. NMPC-16
Due Date: April 15, 2013

Case No. 12-E-0577 – Proceeding on Motion of the Commission to Examine Repowering Alternatives to Utility Transmission Reinforcements

Request for Information

From: Niagara Mohawk Power Corporation d/b/a National Grid

To: NRG Energy, Inc.

Request: Natural Gas Costs (Option 3)

Attachment C indicates that:
"Buyer will purchase and arrange delivery of natural gas to the CCGT project."

a. Please clarify if this statement also applies to gas for the peaking unit proposal in Option 3.
b. If the answer to (a) is "yes," please list all categories of costs NRG anticipates a buyer would incur to "purchase and arrange delivery of natural gas" to the peaking unit project.
c. If the answer to (a) is "yes," please provide all costs, estimates, forecasts, projections, etc., for each category of cost identified in response to (b), for each year of the proposed term.
d. If the answer to (a) is "yes," please provide all estimates, forecasts, projections, etc., of natural gas volumes the buyer would be responsible to purchase and arrange delivery of for each year of the proposed term.
e. Please describe the form of tolling agreement for the peaking units proposal.
    i. List and describe all items and/or services that would be included in the proposed tolling agreement.
    ii. List and describe all items and/or services that would be excluded from the proposed tolling agreement that would be the buyer's responsibility to procure. What is NRG's estimate of the costs for NRG Power Marketing Services Group to provide those items and/or services that are excluded from the proposed tolling agreement?

Response:

a) Yes

b) The following categories should be included in the delivered cost of natural gas to a power production facility:

- **Commodity –** Cost of the natural gas commodity

- **Transportation –** Variable Cost (commodity fees and fuel) associated with moving gas through the pipeline network from a liquid delivery point to the facility burner tip

- **Taxes** – any applicable sales, use or gross receipts tax that may be assessed. It is NRG's understanding natural gas used in the production process (i.e. electricity generation) is exempt from New York State sales tax.

- **Balancing** – Cost for the capability to balance inter-day gas needs

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

Name of Respondent:

Jonathan Baylor

Date of Reply:

April 15, 2013

Request Date: April 1, 2013 Request No. NMPC-17
Due Date: April 15, 2013

Case No. 12-E-0577 – Proceeding on Motion of the Commission to Examine Repowering Alternatives to Utility Transmission Reinforcements

Request for Information

From: Niagara Mohawk Power Corporation d/b/a National Grid

To: NRG Energy, Inc.

Request: Cost Escalation (Option 1-CCGT)

Attachment A states that "Annual Escalation" is "Greater of 2.5% or CPI."

a. Why is CPI the proposed escalation index?
b. What is the justification for minimum escalation of 2.5%?
c. The "Indicative Pricing Structure" provides that "Variable O&M Charge" for the CCGT project is $3.00/MWh in $ 2013. Based on the proposed June 1, 2017 Commercial Operation Date, please confirm that the minimum Variable O&M Charge in the first year of the proposed term (June 2017) would be $3.31/MWh ($3.00/MWh times four years of minimum (i.e., 2.5%) annual escalation). If it is not, please provide the correct value and explain how it was derived.
d. The "Indicative Pricing Structure" provides that "Capacity" for the CCGT project is $17.00/kW-month in $ 2013. Based on the proposed June 1, 2017 Commercial Operation Date, please confirm that the minimum CCGT Capacity Charge in the first year of the proposed term (June 2017) would be $18.76/kW-month ($17.00/kW-month times four years of minimum (i.e., 2.5%) annual escalation). If it is not, please provide the correct value and explain how it was derived.

Response:

[redacted]

[redacted]

[redacted]

[redacted]

Name of Respondent: Date of Reply:

Jonathan Baylor April 15, 2013

Request Date: April 1, 2013 Request No. NMPC-18
Due Date: April 15, 2013

Case No. 12-E-0577 – Proceeding on Motion of the Commission to Examine Repowering Alternatives to Utility Transmission Reinforcements

Request for Information

From: Niagara Mohawk Power Corporation d/b/a National Grid

To: NRG Energy, Inc.

Request: Cost Escalation (Option 1-Refueled Unit 2)

Attachment A states that "Annual Escalation" is "Greater of 2.5% or CPI."

a. Why is CPI the proposed escalation index?
b. What is the justification for minimum escalation of 2.5%?
c. The "Indicative Pricing Structure" provides that "Capacity" for the Refueled Unit 2 project is $17.00/kW-month in $ 2013. Based on the proposed June 1, 2015 Commercial Operation Date, please confirm that the minimum Refueled Unit 2 Capacity Charge in the first year of the proposed term (June 2015) would be $17.86/kW-month ($17.00/kW-month times two years of minimum (i.e., 2.5%) annual escalation). If it is not, please provide the correct value and explain how it was derived.

Response:

[redacted]

[redacted]

[redacted]

Name of Respondent: Date of Reply:

Jonathan Baylor April 15, 2013

Request Date: April 1, 2013 Request No. NMPC-19
Due Date: April 15, 2013

Case No. 12-E-0577 – Proceeding on Motion of the Commission to Examine Repowering Alternatives to Utility Transmission Reinforcements

Request for Information

From: Niagara Mohawk Power Corporation d/b/a National Grid

To: NRG Energy, Inc.

Request: Cost Escalation (Option 2-Refueled Units 2, 3, 4)

Attachment B states that "Annual Escalation" is "Greater of 2.5% or CPI."

a. Why is CPI the proposed escalation index?
b. What is the justification for minimum escalation of 2.5%?
c. The "Indicative Pricing Structure" provides that "Capacity" for the Refueled Units 2, 3 and 4 project is $9.50/kW-month in $ 2013. Based on the proposed June 1, 2015 Commercial Operation Date, please confirm that the minimum Refueled Units 2, 3 and 4 Capacity Charge in the first year of the proposed term (June 2015) would be $9.98/kW-month ($9.98/kW-month times two years of minimum (i.e., 2.5%) annual escalation). If it is not, please provide the correct value and explain how it was derived.

Response:

[redacted]

[redacted]

[redacted]

Name of Respondent: Date of Reply:

Jonathan Baylor April 15, 2013

Request Date: April 1, 2013 Request No. NMPC-20
Due Date: April 15, 2013

Case No. 12-E-0577 – Proceeding on Motion of the Commission to Examine Repowering Alternatives to Utility Transmission Reinforcements

Request for Information

From: Niagara Mohawk Power Corporation d/b/a National Grid

To: NRG Energy, Inc.

Request: Cost Escalation (Option 3-peaking units)

Attachment C states that "Annual Escalation" is "Greater of 2.5% or CPI."

a. Why is CPI the proposed escalation index?
b. What is the justification for minimum escalation of 2.5%?
c. The "Indicative Pricing Structure" provides that "Variable O&M Charge" for the peaking units project is $8.00/MWh in $ 2013. Based on the proposed June 1, 2017 Commercial Operation Date, please confirm that the minimum Variable O&M Charge in the first year of the proposed term (June 2017) would be $8.83/MWh ($8.00/MWh times four years of minimum (i.e., 2.5%) annual escalation). If it is not, please provide the correct value and explain how it was derived.
d. The "Indicative Pricing Structure" provides that "Capacity" for the peaking units project is $15.00/kW-month in $ 2013. Based on the proposed June 1, 2017 Commercial Operation Date, please confirm that the minimum Capacity Charge in the first year of the proposed term (June 2017) would be $16.56/kW-month ($15.00/kW-month times four years of minimum (i.e., 2.5%) annual escalation). If it is not, please provide the correct value and explain how it was derived.

Response:

[redacted]

[redacted]

[redacted]

[redacted]

Name of Respondent:	Date of Reply:
Jonathan Baylor	April 15, 2013

Attachment F to NRG Energy, Inc.
Response to NMPC-15 and NMPC-16

	Henry Hub Price ($/mmBtu)	TETCO M3 Delivered Basis	Delivered Cost ($/mmBtu)
5/1/2013	$ 4.09	$ 0.15	**$ 4.24**
6/1/2013	$ 4.13	$ 0.16	**$ 4.29**
7/1/2013	$ 4.17	$ 0.21	**$ 4.38**
8/1/2013	$ 4.19	$ 0.20	**$ 4.39**
9/1/2013	$ 4.18	$ 0.11	**$ 4.28**
10/1/2013	$ 4.18	$ 0.12	**$ 4.30**
11/1/2013	$ 4.24	$ 0.17	**$ 4.41**
12/1/2013	$ 4.38	$ 0.41	**$ 4.79**
1/1/2014	$ 4.46	$ 0.80	**$ 5.26**
2/1/2014	$ 4.43	$ 0.61	**$ 5.04**
3/1/2014	$ 4.37	$ 0.16	**$ 4.53**
4/1/2014	$ 4.05	$ 0.10	**$ 4.15**
5/1/2014	$ 4.05	$ 0.05	**$ 4.10**
6/1/2014	$ 4.07	$ 0.07	**$ 4.13**
7/1/2014	$ 4.10	$ 0.10	**$ 4.19**
8/1/2014	$ 4.11	$ 0.10	**$ 4.21**
9/1/2014	$ 4.11	$ 0.02	**$ 4.13**
10/1/2014	$ 4.13	$ 0.03	**$ 4.16**
11/1/2014	$ 4.20	$ 0.12	**$ 4.32**
12/1/2014	$ 4.37	$ 0.30	**$ 4.67**
1/1/2015	$ 4.46	$ 0.53	**$ 4.98**
2/1/2015	$ 4.44	$ 0.45	**$ 4.89**
3/1/2015	$ 4.36	$ 0.13	**$ 4.49**
4/1/2015	$ 4.04	$ 0.07	**$ 4.11**
5/1/2015	$ 4.05	$ 0.07	**$ 4.12**
6/1/2015	$ 4.07	$ 0.07	**$ 4.14**
7/1/2015	$ 4.11	$ 0.06	**$ 4.17**
8/1/2015	$ 4.12	$ 0.06	**$ 4.19**
9/1/2015	$ 4.13	$ 0.06	**$ 4.19**
10/1/2015	$ 4.16	$ 0.06	**$ 4.22**
11/1/2015	$ 4.23	$ 0.12	**$ 4.35**
12/1/2015	$ 4.40	$ 0.30	**$ 4.70**
1/1/2016	$ 4.50	$ 0.53	**$ 5.02**
2/1/2016	$ 4.47	$ 0.45	**$ 4.92**
3/1/2016	$ 4.39	$ 0.13	**$ 4.52**
4/1/2016	$ 4.07	$ 0.05	**$ 4.12**
5/1/2016	$ 4.08	$ 0.05	**$ 4.13**
6/1/2016	$ 4.11	$ 0.05	**$ 4.16**
7/1/2016	$ 4.14	$ 0.05	**$ 4.19**
8/1/2016	$ 4.16	$ 0.05	**$ 4.21**
9/1/2016	$ 4.17	$ 0.05	**$ 4.22**
10/1/2016	$ 4.20	$ 0.05	**$ 4.25**
11/1/2016	$ 4.29	$ 0.11	**$ 4.40**
12/1/2016	$ 4.48	$ 0.28	**$ 4.76**
1/1/2017	$ 4.57	$ 0.50	**$ 5.07**
2/1/2017	$ 4.55	$ 0.42	**$ 4.97**
3/1/2017	$ 4.47	$ 0.12	**$ 4.59**
4/1/2017	$ 4.14	$ 0.04	**$ 4.17**
5/1/2017	$ 4.15	$ 0.04	**$ 4.19**

Attachment F to NRG Energy, Inc.
Response to NMPC-15 and NMPC-16

6/1/2017	$	4.18	$	0.04	**$**	**4.21**
7/1/2017	$	4.21	$	0.04	**$**	**4.25**
8/1/2017	$	4.23	$	0.04	**$**	**4.27**
9/1/2017	$	4.23	$	0.04	**$**	**4.27**
10/1/2017	$	4.27	$	0.04	**$**	**4.30**
11/1/2017	$	4.37	$	0.11	**$**	**4.48**
12/1/2017	$	4.57	$	0.28	**$**	**4.85**
1/1/2018	$	4.67	$	0.50	**$**	**5.17**
2/1/2018	$	4.65	$	0.42	**$**	**5.07**
3/1/2018	$	4.57	$	0.12	**$**	**4.69**
4/1/2018	$	4.22	$	0.03	**$**	**4.25**
5/1/2018	$	4.24	$	0.03	**$**	**4.26**
6/1/2018	$	4.27	$	0.03	**$**	**4.29**
7/1/2018	$	4.30	$	0.04	**$**	**4.34**
8/1/2018	$	4.32	$	0.04	**$**	**4.36**
9/1/2018	$	4.33	$	0.03	**$**	**4.35**
10/1/2018	$	4.36	$	0.03	**$**	**4.39**
11/1/2018	$	4.48	$	0.11	**$**	**4.59**
12/1/2018	$	4.69	$	0.29	**$**	**4.98**
1/1/2019	$	4.80	$	0.30	**$**	**5.10**
2/1/2019	$	4.78	$	0.28	**$**	**5.06**
3/1/2019	$	4.70	$	0.14	**$**	**4.85**
4/1/2019	$	4.41	$	0.08	**$**	**4.49**
5/1/2019	$	4.43	$	0.06	**$**	**4.49**
6/1/2019	$	4.46	$	0.07	**$**	**4.53**
7/1/2019	$	4.50	$	0.09	**$**	**4.59**
8/1/2019	$	4.52	$	0.09	**$**	**4.61**
9/1/2019	$	4.53	$	0.06	**$**	**4.59**
10/1/2019	$	4.56	$	0.07	**$**	**4.63**
11/1/2019	$	4.68	$	0.20	**$**	**4.88**
12/1/2019	$	4.90	$	0.20	**$**	**5.10**
1/1/2020	$	5.02	$	0.30	**$**	**5.32**
2/1/2020	$	5.01	$	0.28	**$**	**5.28**
3/1/2020	$	4.93	$	0.14	**$**	**5.07**
4/1/2020	$	4.65	$	0.08	**$**	**4.73**
5/1/2020	$	4.67	$	0.06	**$**	**4.73**
6/1/2020	$	4.70	$	0.07	**$**	**4.76**
7/1/2020	$	4.74	$	0.09	**$**	**4.83**
8/1/2020	$	4.76	$	0.09	**$**	**4.86**
9/1/2020	$	4.77	$	0.06	**$**	**4.83**
10/1/2020	$	4.81	$	0.07	**$**	**4.88**
11/1/2020	$	4.93	$	0.20	**$**	**5.13**
12/1/2020	$	5.15	$	0.20	**$**	**5.35**

Request Date: April 4, 2013 Request No. NMPC-21
Due Date: April 18, 2013

Case No. 12-E-0577 – Proceeding on Motion of the Commission to Examine Repowering Alternatives to Utility Transmission Reinforcements

Request for Information

From: Niagara Mohawk Power Corporation d/b/a National Grid

To: NRG Energy, Inc.

Request: Longwood Energy Group (LEG) study

The LEG report dated March 20, 2013 estimates the annual wholesale cost of electric energy for New York consumers will be reduced by $142 million on average over a 10-year period based on the CCGT option.

a. Please provide a copy of the model used to derive the estimated savings.
b. Please list all input values and assumptions used to derive the estimated savings.
c. Please explain in detail the calculations used to arrive at the following wholesale market cost savings:
    i. annual savings of $142 million on average over a 10-year period for New York customers;
    ii. total savings of $1.4 billion over 10 years for New York customers;
    iii. annual savings of $45 million on average over a 10-year period for customers in the vicinity of Dunkirk;
    iv. total savings of $455 million over 10 years for customers in the vicinity of Dunkirk.
d. Please explain in detail the calculation used to arrive at the estimated annual savings of $39 million due to reduced reliance on out-of-state generation.
e. Please indicate whether the estimated annual wholesale market cost savings are net of the costs of the proposed repowering contracts. Explain specifically where the costs of the proposed repowering contracts are reflected in the LEG market price savings estimates.

Response:

a) The Longwood Energy Group study ("LEG Report") was filed as Attachment B to NRG Energy, Inc.'s response to NMPC-2 and NMPC-3. The model used in the model is proprietary and is not property of NRG. Accordingly, NRG is not able to provide the model to National Grid.

b) As described in the LEG Report, the model inputs are derived principally from public sources. The following response is based on NRG"s information and belief.

Natural gas and oil prices are based on regional monthly forward curves published by SNL Financial, and the Energy Information Administration (EIA) Annual Energy Outlook (AEO) 2013, early release issued December 2012. The SNL forward prices through 2019 are used, after which annual increases in the EIA forecast are used to calculate subsequent monthly values from the SNL data. The SNL data are not public and cannot be provided by the respondent in response to this request. The mapping of pipelines to load zones used is listed in Attachment G.

Forward prices in nominal dollars for Henry Hub and each of five pipelines were obtained from SNL Financial for a trade date of November 27, 2012, for delivery months of June 2017 through November 2019. Henry Hub and pipeline prices for December 2019 through December 2025 were extrapolated from the forward market data using growth rates derived from AEO Reference Case natural gas price forecasts for the Electric Power 2 sector, New England region. [redacted]

The AEO price forecasts for each year were first converted from 2010 dollars per thousand cubic feet to nominal dollars assuming a 2% inflation rate. Year-on-year nominal growth ratios were then determined for 2019 through 2025 by dividing the resulting nominal prices for each year by the prior year's prices. Henry Hub and pipeline prices for months beyond November 2019 were then calculated by multiplying the monthly prices for the prior year by the appropriate year-on-year growth ratios derived from the AEO data.

Electricity demand growth assumptions are as projected by NYISO in its 2012 Load & Capacity Data, Version 3, released in April 2012. Because NYISO projects load growth only through 2022, the analysis assumes annual demand growth for subsequent years to remain constant at 2021-2022 levels.

Future thermal generation units are added to meet regional capacity requirements, and future renewable generation (predominantly wind) is added from the NYISO Interconnection Queue to meet the New York state renewable portfolio standard (excluding newly proposed solar energy requirements). The analysis uses NYISO data on announced retirements. New entry and retirement assumptions have been provided in NRG's response to NMPC-2, part f.

The analysis uses emission permit prices from the STARS (The U.S. Environmental Protection Agency's "Science to Achieve Results") 2012 low emission prices scenario. Generator-specific operating parameters used by DAYZER are part of its proprietary database, assembled from public sources.

c) Upon information and belief, the calculations used to arrive at the wholesale energy market cost savings are described below.

   i. The annual average savings of $142 million is one-tenth of the approximately $1.4 billion 10-year savings, described in the response to Part ii. below.

   ii. [redacted]

   iii. The nominal cost reductions were translated into terms of real 2012 dollars, and summed for all zones over the period 2018-2027. They were then discounted by 25% to account for savings assumed to be unattainable by load-serving entities with long-term contracts at prices determined prior to (and therefore unaffected by) the energy price impacts. The resulting 10-year total savings were approximately $1.4 billion.

   iv. The annual average savings of $45 million is one-tenth of the approximately $455 million 10-year savings.

   v. The total savings of $455 million over 10 years for customers in the vicinity of Dunkirk was determined as described above in response to Part c.ii., for load Zones A and B.

d) Upon information and belief, for each scenario and each representative year, DAYZER projected the cost of imports into New York, and revenues for exports out of New York, as the product of the hourly tie flow and the relevant hourly LBMP. The same set of hourly tie flows was used for each scenario. Savings were interpolated, extrapolated, and aggregated as is described for energy cost savings in the response to Part c., to yield an annual average savings of $39 million. Unlike in the energy cost savings calculation, this value was not discounted by 25% to account for long-term contracts.

e) Upon information and belief, the annual wholesale market cost savings are not net of the cost of the repowering contracts.

Name of Respondent:	Date of Reply:
Jonathan Baylor	April 18, 2013

Request Date: April 4, 2013 Request No. NMPC-22
Due Date: April 18, 2013

Case No. 12-E-0577 – Proceeding on Motion of the Commission to Examine Repowering Alternatives to Utility Transmission Reinforcements

Request for Information

From: Niagara Mohawk Power Corporation d/b/a National Grid

To: NRG Energy, Inc.

Request: Longwood Energy Group (LEG) study

The LEG report dated March 20, 2013 estimates annual wholesale cost of installed capacity savings of $159 million over a 10-year period under the CCGT option.

a. Please provide a copy of the model used to derive the estimated savings.
b. Please list all input values and assumptions used to derive the estimated savings.
c. Please explain in detail the calculations used to arrive at the following wholesale installed capacity cost savings:
   i. annual savings of $159 million on average over a 10-year period;
   ii. total savings of $1.6 billion over 10 years;
   iii. annual savings of $42 million on average over a 10-year period for customers in the vicinity of Dunkirk;
   iv. total savings of $417 million over 10 years for customers in the vicinity of Dunkirk.
d. Please indicate whether the estimated annual wholesale installed capacity cost savings are net of the costs of the proposed repowering contracts. Explain specifically where the costs of the proposed repowering contracts are reflected in the LEG ICAP savings estimates.

Response:

a) The Longwood Energy Group study ("LEG Report") was filed as Attachment B to NRG Energy, Inc.'s response to NMPC-2 and NMPC-3. The model used in the model is proprietary and is not property of NRG. Accordingly, NRG is not able to provide the model to National Grid.

b) Please see NRG's Attachment C to NMPC-2 as previously submitted. The capacity balance used in the analysis is provided electronically in Attachment I. The zero point of each demand curve is calculated as 1.12 times UCAP requirements.

c) [redacted]

[redacted]

[redacted]

[redacted] [redacted]

[redacted] [redacted]

[redacted] [redacted]

[redacted] [redacted]

d) The annual wholesale market cost savings are not net of the cost of the repowering contracts.

Name of Respondent:	Date of Reply:
Jonathan Baylor	April 18, 2013

Attachment G

REDACTED

Attachment H

REDACTED

Attachment I

REDACTED

Request Date: April 4, 2013
Due Date: April 15, 2013

Request No. NMPC-23

Case No. 12-E-0577 – Proceeding on Motion of the Commission to Examine Repowering Alternatives to Utility Transmission Reinforcements

Request for Information

From: Niagara Mohawk Power Corporation d/b/a National Grid

To: NRG Energy, Inc.

Request:

Please provide the annual operating costs that would be avoided if the unit(s) or plant were retired, including, for example, annual property taxes, insurance, labor, maintenance, etc.

Response:
NRG has not performed the requested analysis. In accordance with 16 NYCRR Part5.8(c), NRG is not required to develop the information or prepare the study. In addition, the request appears outside the scope of the issues in this proceeding.

Name of Respondent:

Jonathan Baylor

Date of Reply:

April 15, 2013

Request Date: April 4, 2013
Due Date: April 15, 2013

Request No. NMPC-24

Case No. 12-E-0577 – Proceeding on Motion of the Commission to Examine Repowering Alternatives to Utility Transmission Reinforcements

Request for Information

From: Niagara Mohawk Power Corporation d/b/a National Grid

To: NRG Energy, Inc.

Request:

Please provide the retirement costs, including remediation and demolition costs, for each Dunkirk unit.

Response:
NRG has not performed the requested analysis. In accordance with 16 NYCRR Part5.8(c), NRG is not required to develop the information or prepare the study. In addition, the request appears outside the scope of the issues in this proceeding.

Name of Respondent:	Date of Reply:
Jonathan Baylor	April 15, 2013

Request Date: April 4, 2013
Due Date: April 15, 2013

Request No. NMPC-25

Case No. 12-E-0577 – Proceeding on Motion of the Commission to Examine Repowering Alternatives to Utility Transmission Reinforcements

Request for Information

From: Niagara Mohawk Power Corporation d/b/a National Grid

To: NRG Energy, Inc.

Request:

Please discuss whether construction of the gas pipeline needed to deliver natural gas to the repowered plant is expected to trigger the need for Army Corps of Engineers and/or NYSDEC Wetlands permits and/or wetland mitigation. If so, please provide a detailed timeline.

Response: [redacted]

Name of Respondent:

Jonathan Baylor

Date of Reply: [redacted]

April 15, 2013

Request Date: April 8, 2013 Request No. NMPC-26
Due Date: April 18, 2013

Case No. 12-E-0577 – Proceeding on Motion of the Commission to Examine Repowering Alternatives to Utility Transmission Reinforcements

Request for Information

From: Niagara Mohawk Power Corporation d/b/a National Grid

To: NRG Energy, Inc.

Request: Market Revenues

Please clarify for each of the three options which party (buyer or seller) retains the market revenues:

Option 1 (CCGT and Refueled Unit 2):
- (1) CCGT
  - a. Capacity
  - b. Energy
  - c. Ancillary Services
- (2) Refueled Unit 2
  - a. Capacity
  - b. Energy
  - c. Ancillary Services

Option 2 (Refueled Units 2, 3, and 4):
- a. Capacity
- b. Energy
- c. Ancillary Services

Option 3 (Peaker Units):
- a. Capacity
- b. Energy
- c. Ancillary Services

Response:
Option 1:

- [redacted]

Option 2:

- [redacted]

[redacted]

Option 3:

- [redacted]

<u>Name of Respondent:</u> <u>Date of Reply:</u>

Jonathan Baylor 4/18/13

Request Date: April 8, 2013 Request No. NMPC-27
Due Date: April 18, 2013

Case No. 12-E-0577 – Proceeding on Motion of the Commission to Examine Repowering Alternatives to Utility Transmission Reinforcements

Request for Information

From: Niagara Mohawk Power Corporation d/b/a National Grid

To: NRG Energy, Inc.

Request: Operating characteristics

Please provide the following operating characteristics information for each unit in each option in NRG's repowering proposal:

Option 1 (CCGT and Refueled Unit 2):

(1) CCGT

a. Maximum Winter Capacity
b. Maximum Summer Capacity
c. Minimum Operating Capacity
d. Full Load Heat Rate (if different from those provided in NRG's RFP response)
e. Average Heat Rate at Minimum Capacity
f. Heat Rate Curves
g. Start-Up Energy
h. Start-Up and Shut-Down times; minimum up and down times
i. Ramp Rates
j. Forced Outage Rate

(2) Refueled Unit 2

a. Maximum Winter Capacity
b. Maximum Summer Capacity
c. Minimum Operating Capacity
d. Full Load Heat Rate (if different from those provided in NRG's RFP response)
e. Average Heat Rate at Minimum Capacity
f. Heat Rate Curves
g. Start-Up Energy
h. Start-Up and Shut-Down times; minimum up and down times
i. Ramp Rates
j. Forced Outage Rate

Option 2 (Refueled Units 2, 3, and 4):

a. Maximum Winter Capacity
b. Maximum Summer Capacity

c. Minimum Operating Capacity
d. Full Load Heat Rate (if different from those provided in NRG's RFP response)
e. Average Heat Rate at Minimum Capacity
f. Heat Rate Curves
g. Start-Up Energy
h. Start-Up and Shut-Down times; minimum up and down times
i. Ramp Rates
j. Forced Outage Rate

Option 3 (Peaker Units):

a. Maximum Winter Capacity
b. Maximum Summer Capacity
c. Minimum Operating Capacity
d. Full Load Heat Rate (if different from those provided in NRG's RFP response)
e. Average Heat Rate at Minimum Capacity
f. Heat Rate Curves
g. Start-Up Energy
h. Start-Up and Shut-Down times; minimum up and down times
i. Ramp Rates
j. Forced Outage Rate

Response:

Option 1 (CCGT) – estimated values, subject to final design parameters

[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]

[redacted]

Option 1 (Refueled Unit 2)

[redacted]		[redacted]	
[redacted]		[redacted]	
[redacted]		[redacted]	

[redacted]

[redacted]

[redacted]		[redacted]	
[redacted]		[redacted]	
[redacted]		[redacted]	

[redacted]

[redacted]

[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]

* As provided in the proposal term sheet

Name of Respondent: Jonathan Baylor

Date of Reply: 4/18/13

Request Date: April 8, 2013 Request No. NMPC-28
Due Date: April 18, 2013

Case No. 12-E-0577 – Proceeding on Motion of the Commission to Examine Repowering Alternatives to Utility Transmission Reinforcements

Request for Information

From: Niagara Mohawk Power Corporation d/b/a National Grid

To: NRG Energy, Inc.

Request:

Page 8 of the Longwood Energy Group report defines the "base case" as:
"Dunkirk retired and any transmission upgrades required in the absence of the repowered plant." Please provide details on the transmission upgrades considered for the Base Case (referred as "Dunkirk Historic" case) described in the Longwood Energy Group's economic study.

Response:
Please refer to the response of Jeff Maher and Dan Glenning to information request DPS-1 in Case No. 12-E-0136, attached as Attachment J. That response contains three tables (1, 2, and 3), listing transmission upgrades to be made under various circumstances, as described in the body of the exhibit.

In the base case (Dunkirk retires), the Longwood Energy Group's study assumed conservatively that the following transmission facilities listed in the exhibit would be operational, by the dates listed:

- All facilities in Table 1
- Facilities in Tables 2 and 3 indicated as required with Dunkirk in service ("yes" in column 3)
- Facilities in Tables 2 and 3 indicated as not required with Dunkirk in service ("no" in column 3)

Name of Respondent: Date of Reply:

Jonathan Baylor 4/18/13

Request Date: April 8, 2013 Request No. NMPC-29
Due Date: April 18, 2013

Case No. 12-E-0577 – Proceeding on Motion of the Commission to Examine Repowering Alternatives to Utility Transmission Reinforcements

Request for Information

From: Niagara Mohawk Power Corporation d/b/a National Grid

To: NRG Energy, Inc.

Request: Option 3

Please describe the interconnection points for each of the peaking units described in NRG's Option 3. Which units should be interconnected to the 115kV and 230KV systems?

Response:
[redacted]

Name of Respondent: Date of Reply:

Jonathan Baylor 4/18/13

Request Date: April 8, 2013 Request No. NMPC-30
Due Date: April 18, 2013

Case No. 12-E-0577 – Proceeding on Motion of the Commission to Examine Repowering Alternatives to Utility Transmission Reinforcements

Request for Information

From: Niagara Mohawk Power Corporation d/b/a National Grid

To: NRG Energy, Inc.

Request:

Please indicate NRG's assumption regarding costs of procuring Reliability Support Services from NRG in relation to the Options proposed in the repowering proposal. Is it NRG's assumption that a Reliability Support Service Agreement continue in force through the lifetime of the Dunkirk Historic case (i.e., the Base Case)?

Response:
The Longwood Energy Group study Base Case assumed all units at Dunkirk were retired and a transmission upgrade was in place.

Name of Respondent:	Date of Reply:
Jonathan Baylor	4/18/13

Request Date: April 8, 2013 Request No. NMPC-31
Due Date: April 18, 2013

Case No. 12-E-0577 – Proceeding on Motion of the Commission to Examine Repowering Alternatives to Utility Transmission Reinforcements

Request for Information

From: Niagara Mohawk Power Corporation d/b/a National Grid

To: NRG Energy, Inc.

Request: Cost responsibility – Emissions

a. Please clarify the air emissions responsibilities and rights of the Seller and the Buyer for each unit under each option.
b. Which party will be financially responsible for any emissions allowances required under existing CAIR and RGGI programs, as well as any successor program or additional programs?
c. Provide estimates of annual emissions (CO_2, NO_X and SO_2) for each unit under each option.

Response:

[redacted]

[redacted]

[redacted]

Name of Respondent: Date of Reply:

Jonathan Baylor 4/18/13

Date of Request: November 5, 2012 Request No. DPS-1 (JJA-1)
Due Date: November 15, 2012

Case 12-E-0136

Petition of Dunkirk Power LLC and NRG Energy, Inc. for a Waiver of Generator Retirement Requirements

STAFF OF THE DEPARTMENT
OF PUBLIC SERVICE
INTERROGATORY/DOCUMENT REQUEST

Request No.:	DPS-1
Requested By:	Jerry Ancona
Date of Request:	11/5/12
Reply Date:	11/15/12
Subject:	Dunkirk Part 2 Reliability Study Report (submitted 9/26/12)

Specific Information Requested:

Please list those projects which need to be completed to eliminate dependence on the Dunkirk Generating Plant for local reliability requirements; indicating also the anticipated completion date of each of those projects.

Response:

The projects needed to reduce the risk of thermal or voltage issues with three of the four Dunkirk units out of service are listed below in Table 1. These projects do not address all reliability concerns in the region, but merely reduce the reliability risks to an acceptable level with three of the four units removed from service.

The projects noted in Table 1 to add capacitor banks to Gardenville, Huntley and Homer Hill were determined to be required even with Dunkirk in service. It was determined that shutdown of the Dunkirk generation would result in many existing issues in the area getting worse, thereby accelerating the need for these projects.

Table 1

Project	Anticipated Completion Date (Note 1)
Addition of a 75 MVAr capacitor bank at the Huntley 115kV switchyard Note: One of the two existing mobiles capacitor banks installed at Huntley will remain in service, the other will be removed as the permanent capacitor is installed in its place.	December 1, 2012
Moving Bennett Rd station from line #142 to line #161.	December 15, 2012
Moving Station #139 from circuits #141 and #142 to circuits #149 and #150	January 31, 2013
Addition of a second capacitor bank at Homer Hill station. This second capacitor bank will initially be operated at 25.6 MVAr	March 31, 2013
Moving Station 55 from circuits #141 and #142 to circuits #145 and #146	May 31, 2013
Addition of a 230kV breaker at Huntley, which creates a new bus section.	May 15, 2013
Addition of a 230kV breaker at Packard, which creates a new bus section	May 31, 2013
Addition of four 75 MVAr capacitor banks on four different bus sections at the Gardenville 115kV switchyard.	May 31, 2013
Installation of the mobile capacitor bank removed from Huntley at Dunkirk	May 31, 2013

Note 1: All dates listed in Table 1 were developed prior to Hurricane Sandy and must be re-evaluated once the storm response is completed, especially for some of the near term dates listed in the table. The Company is committed to completing the projects in Table 1 on or before May 31, 2013.

The additional projects needed to reduce the risk of thermal or voltage issues with the fourth and final Dunkirk unit out of service are listed in Table 2. These additional projects do not address all reliability concerns in the region, but merely reduces the reliability risks to an acceptable level such that all Dunkirk units could be removed from service.

The projects noted in Table 2 to build Five Mile Rd, reconductor line #171, add capacitor banks and increase the output of capacitor banks at Andover and Homer Hill were determined to be required even with Dunkirk in service. However, the shutdown of the Dunkirk generation would result in many existing issues in the area getting worse, thereby accelerating the need for these projects.

Table 2

Project	**Anticipated Completion Date**	**Required with Dunkirk Generation In Service**
Addition of two 33.3 MVAr capacitor banks on the two Dunkirk 115kV bus sections. • The first capacitor bank • The second capacitor bank	 November 2013 June 2014	No
Addition of a second 75 MVAr capacitor bank at the Huntley 115kV switchyard.	June 2015	No
Construction of Five Mile Rd, a new 345/115kV station north of Homer Hill station connecting to the Homer City – Stolle 345kV line #37 and the Gardenville – Homer Hill #151 and #167 circuits. This station is planned to include a single 345/115 standard size 448 MVA transformer and a single 25 MVAr capacitor bank.	June 2015	Yes
Reconductoring the Warren – Falconer #171 line.	June 2015	Yes
Closure of the Normally Open switch at Andover station. This change is anticipated to be made following the completion of Five Mile Rd.	June 2015, will be integrated with Five Mile Road Project Plan	No (would only be closed for certain outage conditions)
Reinstallation of the previously removed fuses to return the output of the Andover capacitor bank to its designed size of 15 MVAr. This change is anticipated to be made following the completion of Five Mile Rd.	June 2015, will be integrated with Five Mile Road Project Plan	No
Reinstallation of the previously removed fuses to return the output of the two capacitor banks at Homer Hill to their full designed size of 32 MVAr and 33 MVAr. The fuses will be added back into both capacitor banks after the completion of Five Mile Rd Station	June 2015, will be integrated with Five Mile Road Project Plan	Yes
Reconductoring of the two 115kV lines between Five Mile Rd and Homer Hill, each approximately 7.4 miles in length.	June 2016 (Note 2)	No

Note 2: Under normal schedules assuming no Article VII filing requirements, a June 2016 date is expected completion date; however, National Grid is currently evaluating ways to further expedite the project to align with June 2015 date.

In addition to the above projects, the projects listed in Table 3 are required to address remaining reliability concerns in the area. The Company has reviewed the risks associated with the reliability concerns addressed by these upgrades and has determined that these projects do not need to be completed prior to the complete shutdown of all generation at the Dunkirk Generating Plant; however, this is assuming that they are completed within the time frames identified below. Accepting the reliability risks that the projects in Table 3 are intended to address on a long term/permanent basis is not considered acceptable by the Company.

Table 3

Project	**Anticipated Completion Date**	**Required with Dunkirk Generation In Service**
Installation of a second breaker in series with the existing Lockport 115kV bus tie breaker.	May 2014	Yes
Reconductoring the Niagara – Packard #195 line.	June 2014	Yes
Reconductoring a 0.3 mile section the Gardenville – Erie #54 line	June 2015	Yes
Reconductoring of one mile of the Niagara – Gardenville #180 line	June 2016 (Note 3)	No
A complete rebuild of the Gardenville 115kV station including replacement of TB #3 and #4 with larger units and four 75 MVAr capacitor banks	March 2017	Yes
Installation of a second breaker in series with the existing Dunkirk 115kV bus tie breaker.	June 2018	Yes
Reconductoring of 14 miles of the Packard – Erie #181 line	June 2018 (Note 3)	No

Note 3: Date may be modified to coordinate with Gardenville Rebuild outage plan.

Name of Person
Preparing Response: __Jeff Maher and Dan Glenning ____________Date: _11/13/2012_