

Independent Study to Establish
Parameters of the ICAP Demand
Curve for the New York Independent
System Operator

NERA

Economic Consulting

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I. Executive Summary

In 2003, the NYISO implemented an Installed Capacity¹ (ICAP) Demand Curve mechanism. The ICAP Demand Curve is used in the ICAP Spot Market Auction conducted for each month. The ICAP Demand Curves act as bids to buy capacity in the ICAP Spot Market Auctions.

The NYISO updated the Demand Curves in 2004 for the 2005/06, 2006/07 and 2007/08 Capability Years. That update was based upon an independent study conducted by Levitan & Associates, Inc. (LAI), input from the NYISO Market Advisor and input from stakeholders. The NYISO updated the Demand Curves again in 2007 for the 2008/09, 2009/10 and 2010/11 Capability Years and again in 2010 for the 2011/12, 2012/13 and 2013/14 Capability Years. Those updates were based upon independent studies conducted by NERA Economic Consulting (NERA), assisted by Sargent & Lundy LLC (S&L), input from the NYISO Market Advisor and input from stakeholders. The Demand Curve process calls for the Demand Curves to be updated every three years. The NYISO again retained NERA assisted by S&L to perform an independent Demand Curve parameter update study applicable to Capability Years 2014/15, 2015/16 and 2016/17.

NERA was responsible for the overall conducting of the study and led the effort with respect to formulating the financial assumptions, estimating energy and ancillary services net revenues and developing the recommended Demand Curves. S&L was primarily responsible for developing construction cost estimates, operating cost data and plant operating characteristics. NERA and S&L collaborated to identify the ~~potential technology choice~~peaking plant type for each region².

¹ Terms with initial capitalization used but not defined herein have the meaning set forth in the NYISO's Market Administration and Control Area Services Tariff (Services Tariff) or if not defined in the Services Tariff, as defined in the Open Access Transmission Tariff.

² The Demand Curve process calls for a Demand Curve for New York City (NYC), Long Island (LI) ~~and~~, the New York Control Area (NYCA), and any New Capacity Zone established by NYISO. The New Capacity Zone consists of Load Zones G, H, I and J. NERA and S&L developed the net cost of new entry for NYC, LI, the Capital Region, the Central Region and the ~~lower Hudson valley (LHV). The LHV will be implemented in the market as a New Capacity Zone beginning May, 2014.~~ Lower Hudson Valley (LHV, which consists of G,H, and I).

In considering the study, the Services Tariff was the primary guide. Particularly, Section 5.14.1~~(b)~~.2 of that Tariff section specifies that the update shall be based upon and consider the following:

- the current localized levelized embedded cost of a peaking plant in each NYCA Locality, the Rest of State, and any New Capacity Zone ~~and the Rest of State~~, to meet minimum capacity requirements;
- the likely projected annual Energy and Ancillary Services revenues of the peaking ~~unit~~plant over the period covered by the adjusted ICAP Demand Curves, net of the costs of producing such Energy and Ancillary Services, under conditions in which the available capacity would equal the minimum Installed Capacity requirement plus the capacity of the peaking plant;
- the appropriate shape and slope of the ICAP Demand Curves, and the associated point at which the dollar value of the ICAP Demand Curves should decline to zero; and
- the appropriate translation of the annual net revenue requirement of the peaking plant determined from the factors specified above, into monthly values that take into account seasonal differences in the amount of capacity available in the ICAP Spot Market Auctions.

The Services Tariff further specifies that:

“a peaking unit is defined as the unit with technology that results in the lowest fixed costs and highest variable costs among all other units’ technology that are economically viable, and a peaking plant is defined as the number of units (whether one or more) that constitute the scale identified in the periodic review.”

It is clear that the Services Tariff requires the update to identify the peaking plant with the lowest fixed costs and highest variable costs that is economically viable. This unit will not necessarily be the lowest “net-cost”³ unit under current conditions. It is possible that a more expensive capital cost unit with a lower variable or operating cost would have a lower net cost. For example, a combined cycle unit may have a lower net cost as a result of higher energy net revenues. The Tariff, however,

³ Net-cost refers to the difference between the annual fixed cost and annual energy and ancillary service net revenues.

does not call for the lowest net-cost unit. Rather, it requires that the update be based upon the net-cost of the lowest capital cost and highest operating cost unit that is economically viable. The NYISO also expressed that the Market Monitoring Unit has requested that the NYISO consider basing the Demand Curve on a plant other than peaking plant because using a peaking plant to establish the Demand Curve if it was not the lowest net cost unit may lead to inefficiencies.

Therefore, at NYISO's request, we also examined the localized levelized costs and net energy and ancillary service revenues of the lowest net cost plant ~~other than~~, not a peaking plant, which was determined through a screening process to be a combined cycle unit. Those costs are provided for informational purposes.

As part of this study, we assumed that only a unit that could be constructed practically in a particular location would qualify. This study examines in detail three types of units, representing three technology options. The first technology option is reciprocating engines – the least cost of which is the Wartsila 18V50DF or 18V50SG, dependent on location. The second technology option is aeroderivative combustion turbines – the least cost of which is the GE LMS100. The third technology option is combined cycle units which are represented by the Siemens SGT6-5000F(5). Larger “frame” (industrial) combustion turbines which were examined in past resets for the NYCA ICAP Demand Curve which is based on a plant located in the current Rest of State (Load Zones A-F), “current ROS” ~~in past resets~~, are no longer a viable option, as Selective Catalytic Reduction would now be required and ~~are~~ is not a proven technology in conjunction with frame machines.

A review of these units showed the following:

1. The LMS 100 has lower capital and higher operating costs than the Siemens SGT6-5000F(5) combined cycle unit and the Wartsila reciprocating engines. It is the economically viable peaking unit as defined by the Services Tariff. -Demand Curves were not developed for the Wartsila reciprocating engines.
- ~~2. The combined cycle plant (NTD—This will be written after energy results are complete)~~
2. The Siemens SGT6-5000F(5) combined cycle plant would result in a lower Demand Curve in all locations except NYC. In NYC the Siemens SGT6-5000F(5) combined cycle plant would not result in a lower Demand Curve even if it was able to operate in such a cycling mode as to qualify for the tax abatement. NERA does not, however, recommend the Demand Curve be set

in any location based on the Siemens SGT6-5000F(5) combined cycle plant as it does not meet the definition of a peaking plant as set forth in the Services Tariff. The Service Tariff calls for the plant with the lowest fixed cost and highest variable cost that is economically viable. That plant type is the LMS 100 which has a lower fixed and higher variable cost than a combined cycle (“CC”) and is economically viable to meet peaking needs.

The LMS100 was selected as the peaking unit for, the New Capacity Zone identified as Load Zones G-J (G-J Locality), NYC, LI and the current Rest of State. The NYISO’s proposal for a New Capacity Zone also will propose to redefine Rest of State so that the NYCA ICAP Demand Curve would be based on ~~Load Zones A-F. As discussed below, the location selected for the NYCA ICAP Demand Curve would be the same in this reset because it is proposed to be located in Load Zone F.~~ [NTD—This assumes that the net energy analysis when complete confirms that net energy revenues result in a lower net costs in Zone F than in Zone C.] Load Zones A-F. We show costs herein for a location in Zone C and one in Zone F. As the report is finalized and costs are refined, we will only show one location in Rest of State. A comparison of results for the first year of the current update to the Demand Curve to the last year of the previous update period is presented below.

~~[NTD—In table below some cells will not apply and will be filled in NA. Table will be updated when energy results are complete]~~

Table I-1

Demand Curve Values at Reference Point:

Values for Capacity Years 2013/2014 and 2014/2015

	<i>2010 DC Value for 2013/2014</i> <i>2013 dollars/kW-year</i>			<i>2013 Update for 2014/2015</i> <i>2014 dollars/kW-year</i>		
	Annual Fixed Cost	Energy and AS Net Revenues	Net Costs	Annual Fixed Cost	Energy and AS Net Revenues	Net Costs
ROS Frame 7	<u>123.80</u>	<u>27.46</u>	<u>96.34</u>	<u>N/A</u>	<u>N/A</u>	<u>N/A</u>
ROS Zone C LMS100	<u>N/A</u>	<u>N/A</u>	<u>N/A</u>	<u>190.74</u>	<u>28.91</u>	<u>161.83</u>
<u>Zone F LMS100</u>	<u>N/A</u>	<u>N/A</u>	<u>N/A</u>	<u>205.56</u>	<u>42.02</u>	<u>163.54</u>
NYC LMS100	<u>288.29</u>	<u>97.26</u>	<u>191.02</u>	<u>285.63</u>	<u>64.73</u>	<u>220.90</u>
G to J LMS100	<u>N/A</u>	<u>N/A</u>	<u>N/A</u>	<u>227.63</u>	<u>55.96</u>	<u>171.67</u>
ROS LI LMS 100	<u>259.39</u>	<u>151.82</u>	<u>107.57</u>	<u>239.95</u>	<u>125.37</u>	<u>114.58</u>
ROS Zone C CCGT	<u>N/A</u>	<u>N/A</u>	<u>N/A</u>	<u>205.57</u>	<u>61.86</u>	<u>143.71</u>
<u>Zone F CCGT</u>	<u>N/A</u>	<u>N/A</u>	<u>N/A</u>	<u>214.60</u>	<u>75.72</u>	<u>138.88</u>
NYC CCGT	<u>N/A</u>	<u>N/A</u>	<u>N/A</u>	<u>452.69</u>	<u>111.11</u>	<u>341.58</u>
G to J CCGT	<u>N/A</u>	<u>N/A</u>	<u>N/A</u>	<u>253.88</u>	<u>88.82</u>	<u>165.06</u>
LI CCGT	<u>N/A</u>	<u>N/A</u>	<u>N/A</u>	<u>270.66</u>	<u>198.31</u>	<u>72.35</u>

~~We present the values above in 2013 dollars for the current curve and 2014 dollars for the proposed new curves as the curves are stated on that basis. [NTD—When energy results are available we will compare results and present reason for major changes]~~

We present the values above in 2013 dollars for the current curve, and 2014 dollars for the proposed new curves, as the curves are stated on that basis. The Demand Curve reference points for NYC and LI increased by 15% and 6%, respectively. The increase in NYC and LI is primarily due to declines in net energy revenues in NYC and LI. The NYC net energy revenue decline can be explained in large part by the addition of two 500 MW efficient energy generation facilities (Astoria Energy 2 and the Bayonne Energy Center) and a new tie to PJM. In light of these additions, the

decline in net energy revenues is not surprising in direction or magnitude. While the new tie (HTP) is limited for capacity purposes, which could impact the delivery of firm energy, energy need not be firm to impact NYC LBMPs and net energy revenues, and the model we use to reflect HTP captures the dispatch of NYISO and PJM. Additionally, fixed costs in NYC have declined by about \$4 per kW year – explained by a combination of factors, including a reduction in overnight capital and financing costs. The zero crossing point is the quantity of excess capacity at which the price on the Demand Curve drops to zero and together with and the reference point, it establishes the slope of the Demand Curve. Net energy revenues on LI declined by over \$26 per KW year, but the capital costs have also declined by about \$20 per KW year resulting in a net change of about \$6.27 per KW year. The Zone G to J cost was not formally set forth in the last reset. It falls just above the ROS level, attributable to net energy revenues that are higher than ROS units and largely offset higher local construction costs. The most significant change comes in ROS. There, a technology change was necessary due to environmental regulations, and the increased costs of an LMS 100 plant as opposed to a Frame 7 plant, though partially offset by higher energy revenues, has resulted in a very significant (over 75%) increase in the reference point level. This increase would have been greater if not for the recommendation to increase the zero crossing point.

The Demand Curves were developed explicitly analyzing risks. Risks that could reasonably be considered to be symmetrical have no impact on expected value and were not considered in the risk analysis. Risks that were not symmetrical were analyzed in a Monte Carlo risk analysis model, described later in the report, and made available to stakeholders in executable form.

The model recognizes that the NYISO has in place planning and response procedures to prevent capacity from falling short of capacity requirements. Hence, over time, there should be a bias toward surplus capacity conditions. The Demand Curve is developed to be able to accommodate the fact that over time the expected clearing price would be below the target ~~reserve~~reference point. Absent such an accommodation, the Demand Curve would not produce adequate expected revenues to recover cost and would not induce the proper level of investment. -The model we have developed to set the Demand Curve accounts for these factors and, consistent with the Services Tariff, this is done assuming a level of excess equal to the capacity of the peaking plant- (approximately 190 MW).

When using the risk model, the slope of the Demand Curve has a measurable influence on the cost levelization and the Demand Curve reference point. With a bias toward excess capacity, a steep slope requires a higher reference point if there is to be an expectation of full cost recovery. In surplus capacity periods, the Demand Curve will clear below the reference price, and if there is a steep slope, revenues will decline more rapidly than if there is flatter slope. To provide the same expected revenue over the life of the investment, a higher reference point must accompany a steeper slope. ~~For example, if the NYC x-intercept was applied to the NYCA Demand Curve, the reference value would fall by \$y.yy per kW-year. {NTD—will update when energy results are available}~~

The recommended Demand Curves are presented below. For each region the chart shows the current Demand Curve and the 2014/15 recommendation for the Demand Curve. ~~{NTD—to be updated when energy results are available}~~

~~NERA examined the issue of the Demand Curve slope, which is a function of the zero crossing point and shape. The current curves have a single linear slope from the reference value at the target reserve level to zero at 112% of the minimum requirement for the NYCA ICAP Demand Curve and 118% of the minimum requirement for NYC and LI. {NTD—to be updated when energy results are available and further analysis has been done on this issue}~~

Figure I-1 — Proposed Demand Curves - New York City LMS100

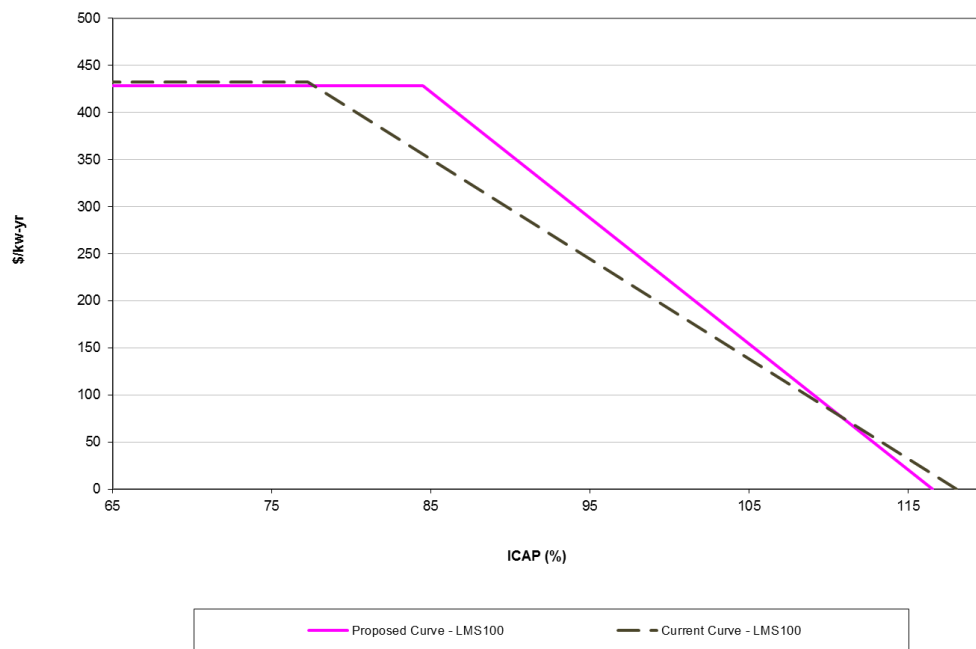


Figure I-2 — Proposed Demand Curves - Long Island LMS100

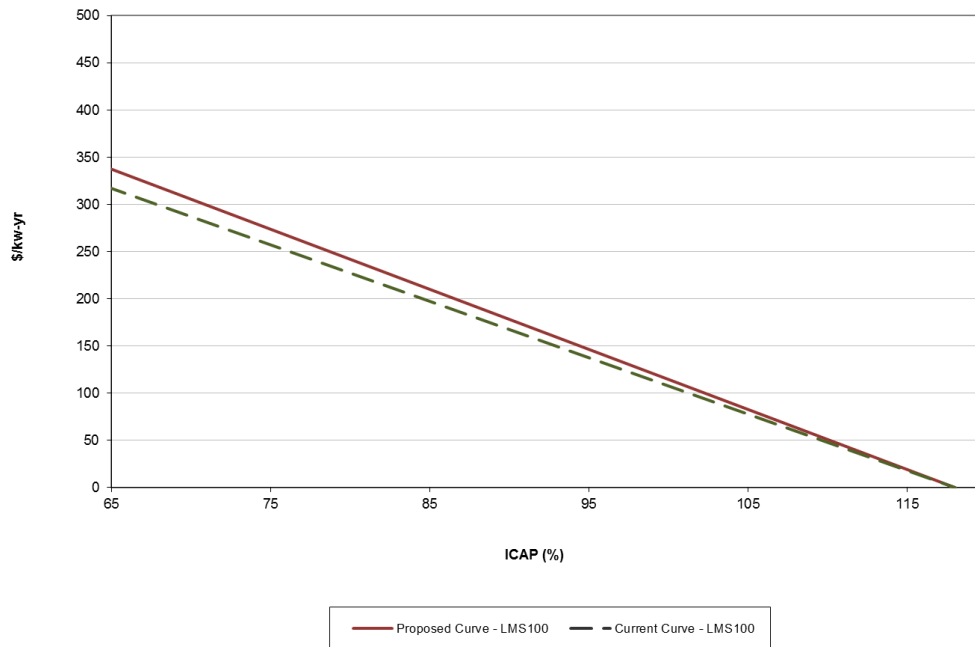


Figure I-3 — Proposed Demand Curves - G-J LMS100

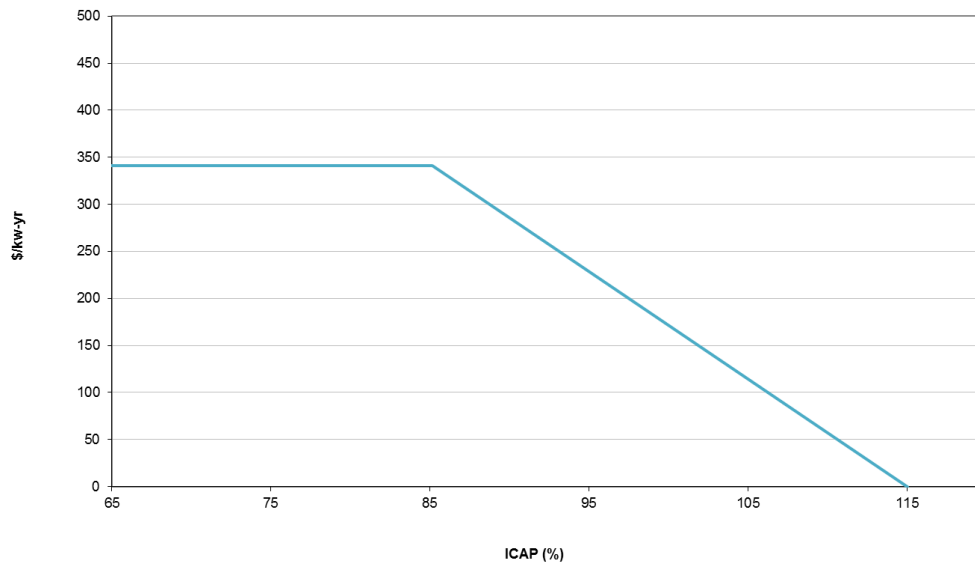


Figure I-4 — Proposed Demand Curves - Capital LMS100

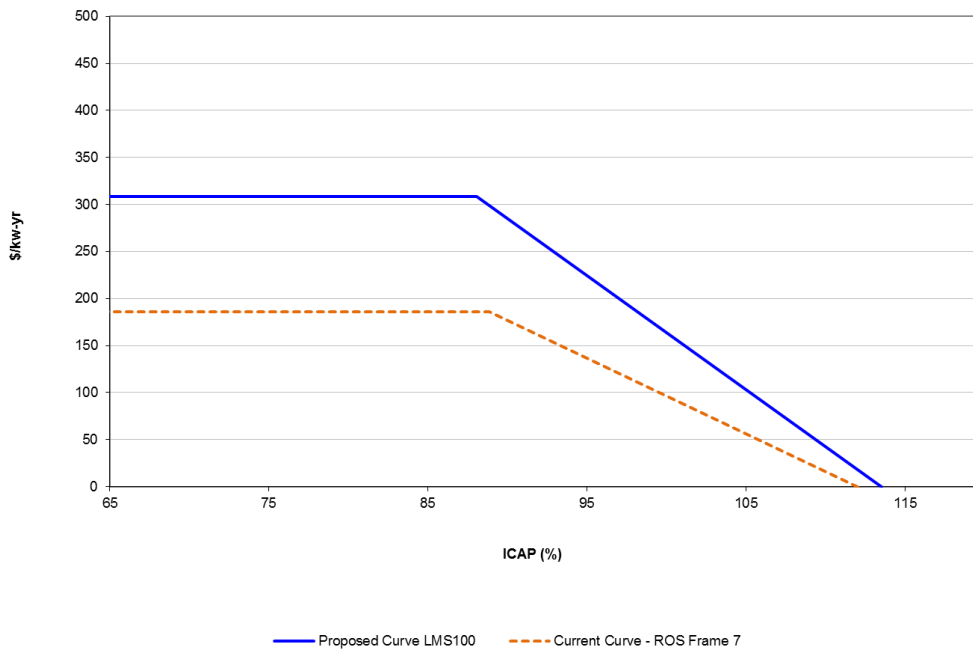
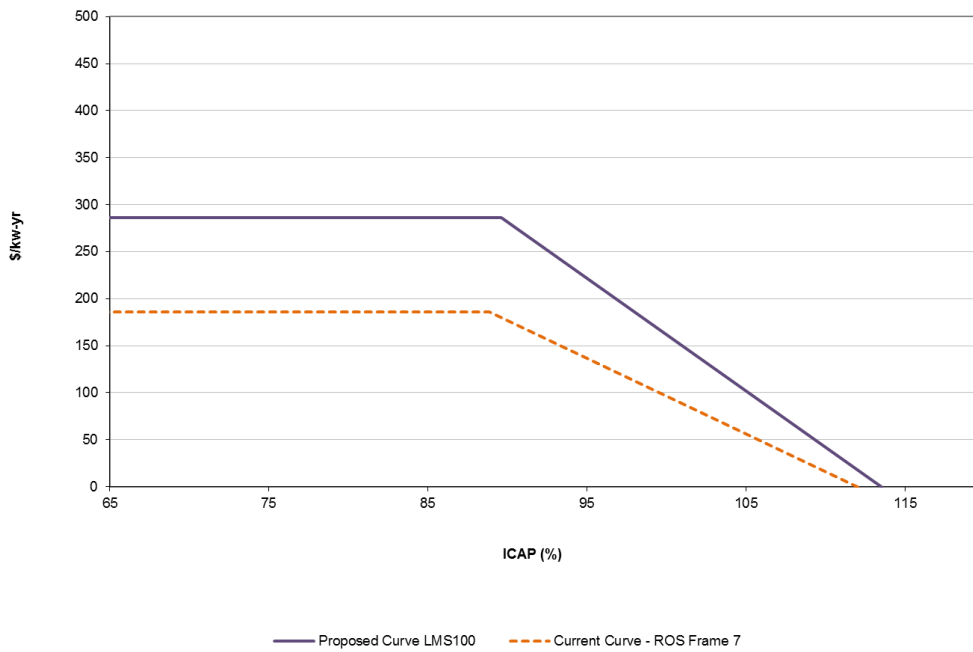


Figure I-5 — Proposed Demand Curves - Central LMS100



NERA examined the issue of the Demand Curve slope, which is a function of the zero crossing point and shape. The current curves have a single linear slope from the reference value at the target reserve level to zero at 112% of the minimum requirement for the NYCA ICAP Demand Curve and 118% of the minimum requirement for NYC and LI. The issue of Demand Curve Slope was examined by FTI in a recent review of NYISO's capacity market (the "FTI Report").⁴ The FTI Report provided a well-reasoned economic argument that the slope of the Demand Curves should reflect the reliability value of capacity. NYISO, in collaboration with FTI performed analyses that utilized the GE MARS program (the program used to develop the NYCA Minimum Installed Capacity Requirements (ICRs) and Locational Minimum Installed Capacity Requirements (LCRs)) to estimate the changes in NYCA loss of loads expectation (LOLE) associated with varying levels of capacity in the market. FTI utilized that data to calculate the implied cost of a loss of load event, and derived reliability based demand curves for each NYCA capacity market region. FTI concluded that while in general the zero crossing points and linear shape of the current Demand Curves did track reliability value, the correspondence between the demand curve and reliability value would be enhanced by slightly reducing the NYC zero crossing point and slightly increasing the NYCA zero crossing point. NERA reviewed the recommendations made by the FTI Report, which would suggest lowering the NYC zero crossing point to 115% from 118% and would suggest increasing the NYCA zero crossing point to 115% from 112%. These modifications would not impair the ability of the Demand Curves to meet other objectives, including providing for revenue stability and leading to reference points that imply reasonable amortization periods. NERA concludes that since FTI Report's analysis and recommendations would improve the economic efficiency of the price signal provided by the Demand Curves without negative consequences on other objectives, the zero crossing point should move in the direction of the FTI recommendations. In this reset, NERA recommends that the zero crossing point for LI be maintained at 118% consistent with the FTI Report, that the NYC crossing point be moved to 116.5% (a point halfway between the current curve and that suggested by the FTI Report) that the ROS (also referred to as NYCA) zero crossing point be moved to 113.5% (a point halfway between the current curve and that suggested by the FTI Report). A movement in the direction of FTI's recommendation, but half the magnitude is the most prudent course. NERA believes a gradual (half the distance) move is

⁴ http://www.nyiso.com/public/webdocs/markets_operations/documents/Studies_and_Reports/Studies/Market_Studies/Final_New_York_Capacity_Report_3-13-2013.pdf -- pages 125 to 132

the best course to ensure that there are no regrets. For Zones J and K, FTI notes an ambiguity and possible conflict in how excess capacity may be valued that would lead to higher zero crossing points than recommended if resolved by one interpretation. Additionally, reliability (LOLE) calculations are extremely sensitive. It is also possible that should NYISO elect to revisit the FTI Study the results may differ. By no regrets we mean that if the interpretation is resolved in a way that would not lead to the NYC zero crossing point being raised or in the event that NYISO revisits the FTI Study⁵ it does not confirm the magnitude of the change, there will be no need to move back from a move that may have gone too far. A move in the direction indicated by the current FTI Study that moves halfway will avoid the possible need to reverse course and will promote certainty and stability. For the new capacity zone (Zones G to J), NERA recommends that a zero crossing point of 115% (midway between that used for NYC and that used for NYCA) be used. The FTI Report did not specifically examine Zones G to J.

⁵ NERA is not suggesting that the study needs to be updated, but if it is the results could differ due to the sensitive nature of the calculations.

III. II. Technology Choice and Construction Cost

The ICAP Demand Curves are derived from the levelized cost of a hypothetical new peaking plant at various locations throughout the NYCA.⁶⁷ The current NYISO Services Tariff states that the periodic review of the ICAP Demand Curves shall assess “the current localized levelized cost of a peaking unit in each NYCA Locality and the Rest of State to meet minimum capacity requirements.” The Services Tariff defines a peaking unit as “the unit with technology that results in the lowest fixed costs and the highest variable costs among all other units’ technology that are economically viable, and a peaking plant is defined as the number of units (whether one or more) that constitute the scale identified in the periodic review.”⁸

Based on this Tariff provision, past reviews of the ICAP Demand Curves have identified the lowest fixed cost, highest variable cost peaking unit that is economically viable. The reference peaking facility chosen in previous reviews has been a gas-fired combustion turbine operating in simple-cycle mode. However, a simple cycle combustion turbine unit will not necessarily be the lowest “net-cost” unit. It is possible that a more expensive capital cost unit with a lower variable or operating cost would have a lower net cost. For example, a combined-cycle unit may have a lower net cost as a result of higher energy net revenues. In establishing the scope for this periodic review, NYISO determined that it would be useful to know if a unit other than a peaking unit as defined by the tariff would have a lower net cost under current conditions.

For this reason, this periodic review of the ICAP Demand Curves included a screening analysis of technologies to identify the technology that results in the lowest Demand Curve Reference Point under current conditions, accounting for the amount of capacity excess associated with the technology. The objective of the screening analysis was to determine whether a technology with more expensive capital cost and a lower variable or operating cost would potentially have a lower Reference Point than the a peaking unit, and thereby merit a more detailed evaluation of capital and

⁶ ~~The 2010 review of the ICAP Demand Curves examined placement of a proxy generating unit outside of NYCA but interconnected with the NYISO grid in Zone J. The cost of this alternative was prohibitive due to lengthy generator lead cables (several miles) and therefore was not considered for this review.~~

⁷ ~~The 2010 review of the ICAP Demand Curves examined placement of a proxy generating unit outside of NYCA but interconnected with the NYISO grid in Zone J. The cost of this alternative was prohibitive due to lengthy generator lead cables (several miles) and therefore was not considered for this review.~~

⁸ Services Tariff, Section 5.14.1(b)

operating costs. Section A of this section describes the screening analysis and results. The analysis has not considered Special Case Resources.⁹¹⁰

Based on the results of the screening analysis, three technologies—simple cycle combustion turbines, a combined cycle plant, and reciprocating engines—were evaluated at each location. The levelized cost analysis described in this section accounts for the location-specific factors affecting the total capital investment, the cost inputs and economic parameter inputs for the levelized cost analysis, and the annual operating cost and performance characteristics for each technology.

Levelized costs generally refer to the capital-related carrying charges, operation and maintenance (O&M), and fuel costs incurred over the plant operating life. For the ICAP Demand Curve analysis, costs are divided into variable costs (those that vary with operation) and non-variable (fixed) costs. The Demand Curve analysis uses the fixed cost components, consisting of the capital-related carrying charges, property taxes, insurance, and fixed O&M. Variable costs, consisting of fuel, emissions costs, and variable O&M, are used to develop net energy and ancillary service revenues in NERA's econometric model of NYISO market prices. Once the levelized annual fixed costs for the unit are established, they indicate a reference point in the Demand Curve at which the net revenues from the energy and ancillary service markets offset the fixed costs. Input assumptions for the cost components are described in the following subsections.

⁹The FTI Consulting report on the NYISO's capacity market states that "[t]he costs to power consumers of reducing consumption in order to provide incremental demand response would not provide a workable basis for setting net CONE, because it is inherently customer specific, rather than a generic cost that can be benchmarked as in the case of a generating facility." The NYISO does not have and is not aware of appropriate data to define the fixed and variable costs that are comparable to a generator, either by "generic" demand response resource category, or in the aggregate. This data issue has been discussed in the ICAP Working Group and there is general agreement that data is not available that could be used in this reset. The use of Demand Response has not been ruled out in future resets.

¹⁰The FTI Consulting report on the NYISO's capacity market states that "[t]he costs to power consumers of reducing consumption in order to provide incremental demand response would not provide a workable basis for setting net CONE, because it is inherently customer specific, rather than a generic cost that can be benchmarked as in the case of a generating facility." The NYISO does not have and is not aware of appropriate data to define the fixed and variable costs that are comparable to a generator, either by "generic" demand response resource category, or in the aggregate. This data issue has been discussed in the ICAP Working Group and there is general agreement that data is not available that could be used in this reset. The use of Demand Response has not been ruled out in future resets.

A. Technology Screening Analysis

For the purposes of this study, we assumed that only a unit that realistically could be constructed in a location would qualify. The following screening criteria were developed to identify candidate technologies:

1. The technology can comply with applicable Federal and New York State environmental requirements.
2. The technology is commercially available, *i.e.*, it is not in a pilot or demonstration phase of development, and it has been successfully operated to generate electricity; and is replicable.
3. The technology is utility plant scale, *i.e.*, it can be interconnected at transmission rather than distribution voltages.
4. The technology is available to most developers; *i.e.*, there are no commercial terms restricting the ability of a developer to acquire or license the technology and fuel for the technology is not restricted or limited in availability.
5. The technology is dispatchable by the NYISO to meet the daily or peak load demands. It has peaking or cycling characteristics and is capable of cycling off during off-peak hours on a daily basis. The technology can be started and achieve minimum load within an hour.

Reflecting the above factors, the plant size would be in the range of 100-400 MW, depending on technology.

Applying these criteria, the following technologies would not qualify as candidate technologies for the reference unit anticipated by the Services Tariff:

- Intermittent power resources (wind, solar) because they are not dispatchable and have low Unforced Capacity in summer (for wind) and winter (for solar).
- Dispatchable renewable technologies (hydropower, biomass, municipal solid waste, landfill gas) because they have limited fuel availability and are not available to most developers.
- Dispersed generation because it does not meet the utility plant scale criterion.

- Fuel cells and storage technologies because they are not economically viable or available to most developers (*e.g.*, compressed air energy storage).
- Nuclear technologies because these plants are normally run at full load, and because changes in load must be planned in advance, which restricts dispatchability.
- Coal technologies because CO₂ emissions are high and carbon sequestration and storage technologies are not commercially available.

Several natural gas technologies have industry proven designs, meet the screening criteria, and will be evaluated for the reference unit. These include combined cycle technology, simple cycle combustion turbines, and reciprocating internal combustion engines.

B. Alternate Technologies Examined in More Detail

In conducting the study, one heavy-duty frame combustion turbine in combined cycle operation, the Siemens SGT6-5000F(5), one aeroderivative hybrid combustion turbine peaking unit, the General Electric LMS100, and one reciprocating internal combustion engine (RICE), the Wartsila 18V50DF (or 18V50SG dependent on location), were examined in detail. From among the many turbine and engine models that might have been chosen for this evaluation, we chose models from three different equipment manufacturers that have competitive heat rates, provide operational flexibility, and can meet New York State environmental requirements.

Heavy-duty frame units such as the SGT6-5000F(5) are large-scale combustion turbines oriented to industrial applications with low capital costs (on a \$/kW basis) and high operating costs (on a \$/MWh basis) in simple cycle operation. Nitrogen oxide (NO_x) emissions are reduced by equipping the units with dry low NO_x (DLN) combustors. The use of selective catalytic reduction technology for NO_x control is problematic because exhaust gas temperatures in simple-cycle mode exceed 850°F, above which the catalyst is damaged irreversibly. Due to the problems with controlling exhaust temperature for inclusion of selective catalytic reduction technology and the high operating cost, the SGT6-5000F(5) in simple cycle operation was not evaluated. The high exhaust energy typical of heavy-duty frame units such as the STG6-5000F(5) makes these units good candidates for operation in a combined cycle configuration. In combined cycle operation, the exhaust of one or more units is directed to a heat recovery steam generator, which drives a steam turbine thus

increasing output and improving efficiency. This results in a higher capital cost, but greatly reduces the plant operating cost. Just as in simple cycle operation, nitrogen oxide (NO_x) emissions are reduced by equipping the units with dry low NO_x (DLN) combustors. Selective catalytic reduction technology can be used for further NO_x control. Since some of the exhaust energy is transferred to the steam cycle before entering the selective catalytic reduction process, there is minimal risk of damaging the catalyst. Inclusion of a CO catalyst may also be necessary to control CO pollutants. Maintenance costs are affected by the duty cycle experienced in operations. As a unit is subjected to more starts and stops, the time between major overhauls decreases.

Aeroderivative units such as the LMS100 are derived from aircraft engines and have operating characteristics that differ from frame combustion turbines. Aeroderivatives are more efficient (lower heat rate) than frame combustion turbines and are maintained based on hours of operations regardless of the number of starts and stops, but have higher capital costs (on a \$/kW basis). NO_x emissions can be reduced by injecting water into the combustion zone; however, aeroderivative exhaust temperatures are low enough to permit use of SCR for NO_x control. Dry low NO_x combustion is available on aeroderivative units to reduce the amount of water used in the NO_x emissions control process. A catalyst may be used to reduce CO emissions.

Reciprocating internal combustion engines such as the Wartsila 18V50DF and 18V50SG operate with a different combustion process than combustion turbine technologies. This combustion process results in high simple cycle efficiency that is largely independent of ambient conditions and site elevation. Due to their relatively small size, inclusion of multiple units in simple cycle is necessary to obtain the equivalent output of a simple cycle aeroderivative or frame combustion turbine. Due to the multiple units required, the engines have a high capital cost (on a \$/kW basis), but a low operating cost (on a \$/MWh basis) as compared to a simple cycle plant. All Wartsila units sold in the United States are pre-equipped with a catalyst to reduce CO and NO_x emissions.

1. **SGT6-5000F(5)**

Siemens has sold more than 180 SGT6-5000F class (60hz) gas turbines in the past twenty years. The 60 Hz “F” class combustion turbine has more than 5.3 million hours of fleet operation. The Siemens SGT6-5000F(5) combustion turbine, with a nominal rating of 228 MW, is capable of operating on natural gas, LNG, distillate oil as well as other fuels. DLN combustors reduce NO_x emissions, when firing natural gas. Water injection is used for NO_x control in the combustion

process when firing fuel oil. The wide range of power generation applications for the SGT6-5000F(5) combustion turbine include combined cycle, cogeneration, simple-cycle peaking and integrated gasification combined cycle (IGCC) in both cyclic and baseload operation with a wide range of fuels. The reliability of the SGT6-5000F(5) combustion turbine has been consistently 99% or better. Easily removable blading and combustion components and advanced service and maintenance technologies increase combustion turbine availability. Rapid start times for combined cycle plants have seen dramatic improvements over the past decade. A modern SGT6-5000F(5) combined cycle plant is capable of ramping from zero load to valves wide open full load in 45 minutes or less. The combustion turbine itself can reach full load within 10-12 minutes. Turndown, in terms of minimum emission compliant load and efficiency, has also seen improvements in the past decade. A Siemens SGT6-5000F(5) combustion turbine remains emission compliant to 40-50% of the base turbine load with a 6-7% degradation in heat rate. This characteristic allows for load following in cycling applications.

2. **LMS100**

The LMS100 is a General Electric aeroderivative combustion turbine that combines the technology of heavy-duty frame engines and aeroderivative turbines to provide cycling capability without the maintenance impact experienced by frame machines; higher simple-cycle efficiency than current aeroderivative machines; fast starts (10 minutes); and high availability and reliability. The LMS100™ system, developed by General Electric in 2004, combines the 6FA compressor technology with CF6®/LM6000™ technology. The airflow from the low pressure compressor enters an intercooler, which reduces the temperature of the airflow before it enters the high-pressure compressor (HPC). Consequently, the HPC discharges into the combustor at ~250°F (140°C) lower than the LM6000™ aeroderivative gas turbine. The combination of lower inlet temperature and less work per unit of mass flow results in a higher pressure ratio and lower discharge temperature, providing significant margin for existing material limits and higher efficiency. The HPC airfoils and casing have been strengthened for this high-pressure condition. The low exhaust temperature (~800°F) allows the inclusion of selective catalytic reduction technology without risk of potential damage to the catalyst. The LMS100 has proven to perform well in cycling applications. The combustion turbine is capable of ramping from zero load to full load in 10 minutes or less under hot, warm or cold start conditions.

Since the first unit was commissioned in 2006, there have been 56 LMS100s sold with 162,000+ cumulative hours as of end of 2012. Both wet low NO_x combustion (the PA model) and dry low NO_x combustion (the PB model) are available. All of the currently installed and operating LMS100s are the PA model. For this study, only the PA model was examined. Due to the low exhaust temperatures, the LMS100 is better suited for simple cycle operation rather than combined cycle operation. Modern main steam temperatures of 1000°F to 1050°F could not be achieved with the exhaust energy from the LMS100. For this study, only simple cycle operation was examined.

3. **Wartsila 18V50DF/18V50SG Reciprocating Internal Combustion Engines**

The 18V50DF and 18V50SG are manufactured by Wartsila and offer a higher efficiency alternative to simple cycle gas turbines. The 18V50DF is dual fuel capable and operates with a compression ignition system (DF - Dual Fuel) while the 18V50SG is capable of firing natural gas only and operates with a spark ignition system (SG – Spark Gas). These reciprocating engines offer a higher simple efficiency than a typical frame or aeroderivative gas turbine. However, the combustion process used in these engines increases emission rates for both NO_x, CO, and VOC's as compared to a simple cycle gas turbine. Each unit is capable of ~18 to 20 MW, so multiple units are required to achieve an output comparable to a simple cycle gas turbine. This allows for an excellent turndown efficiency and minimum load capability when multiple units are installed. Due to the low exhaust energy from these engines, the 18V50DF/SG is not a good candidate for combined cycle operation, though there are several engines currently operating in a combined cycle configuration.

Wartsila has recently been gaining market share in the United States as a major power producer. The Wartsila 18V50DF and 18V50SG have more than 200 operating units worldwide, and their sister unit, the 18V46DF, adds an additional 600 operating engines.

4. **Comparison**

The key characteristics of the three technologies evaluated for this study are shown below. The direct costs are the costs typically within the scope of engineering, procurement, and construction (EPC) contracts, and do not include owner's costs, financing costs, or working capital and inventories.

Table II-1 Key Characteristics of Evaluated Technologies¹¹

Technology	Combined Cycle with Frame	Simple Cycle Turbine Aeroderivative	Reciprocating Internal Combustion Engine
	Siemens SGT6-5000F(5) (1x1x1) ¹²	LMS100 PA	18V50DF/18V50SG
Number of Units	1	2	12
Net Capacity of Units (ICAP MW, Degraded)	334.2 301.7 - 306.0	204.4 183.6 - 186.3	499.4 188.3 - 197.9
Total Cost (\$M)	393 587405 - 606	237 324250 - 339	355 483366 - 499
Total Cost (\$/kW)	1,303341 - 1,932993	1,273344 - 1,761841	1,795852 - 2,567649
Heat Rate (Btu/kWh HHV)	7,095	9,125	8,512
Pressure Ratio	18.9:1	43.3:1	N/A
Exhaust Temperature of Gas Turbine or engine (°F)	1,106	774	707
Water Use (gpm/MGD)	4,383 2.3	600 .9	<400.1
Minimum Load for one unit (ICAP MW, degraded)	206	60.5	16 ¹³
Heat Rate at Minimum Load (Btu/kWh HHV)	7,639	10,490	N/A

The direct cost (\$/kW) and heat rate data show that the LMS100 had lower capital and operating cost than other aeroderivative technologies. The SGT6-5000F(5) has lower capital and higher fuel and operating costs than the LMS100. Appendix 1 shows more detailed information on the cost and performance characteristics of the Siemens SGT6-5000F(5), GE LMS100, and Wartsila 18V50DF/18V50SG technologies. The following section addresses the impact of emissions limitations on technology choice.

¹¹ Based on 100% degraded load, ISO Conditions at site elevation (59F, 60% RH, 165 Ft, AMSL), evaporative (inlet) cooling, 0.85 power factor, and natural gas fuel. The water consumption for the combined cycle unit reflects wet closed cycle cooling; the water consumption for the LMS100 reflects wet cooling for the intercooler.

¹² The designation 1x1x1 refers to one combustion turbine exhausting into one heat recovery steam generator supplying steam to one steam turbine generator.

¹³ [In a multi-engine plant, turning off an engine is preferable to operating several engines at non-optimal load.](#)

C. Emissions Requirements by Location

New fossil fuel-based power generating facilities that emit air contaminants are required to obtain a permit to construct/operate from the New York Department of Environmental Conservation (NYDEC). All three technologies are subject to Title V operating permit regulations in NYCRR Subpart 201.6.¹⁴

To obtain an air permit, the facility proponent must apply to NYDEC in accordance with the procedures prescribed by regulations in 6 NYCRR Part 621. In general, permit applications for new stationary emission sources must include a description of the proposed facility, provide information on the facility's emissions, describe the processes and raw materials being used, identify the height and location of stacks or vents, identify all the requirements that apply to the facility, and describe air pollution controls being applied. Permit applications are processed following the steps in 6 NYCRR Part 621, and may include an opportunity for public review and comment.

New stationary combustion sources are subject to specific air quality regulations limiting emissions from the source. Applicability of the air quality regulations depends on the source type and size, fuel fired, potential emissions, and location. Potential air quality standards include, but are not necessarily limited to:

- New Source Performance Standards (40 CFR Part 60)
 - Subpart KKKK – Stationary Combustion Turbines
 - Subpart IIII – Stationary Compression Ignition Internal Combustion Engines
 - Subpart JJJJ – Stationary Spark Ignition Internal Combustion Engines
 - Subpart TTTT – Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources (proposed rule);
- National Emission Standards for Hazardous Air Pollutants (40 CFR Part 63)
 - Subpart YYYY – Stationary Combustion Turbine

¹⁴ The Subpart 201-6 Title V operating permit regulations apply to any major source (as defined under Subpart 201-2 of the regulations), and any stationary source subject to a standard or limitation, or other requirement, under the Federal New Source Performance Standards (NSPS) in 40 CFR Part 60, *et seq.* Stationary combustion turbines (simple- and combined-cycle) are subject to a Federal NSPS (40 CFR Part 60 Subpart KKKK), and stationary reciprocating internal combustion engines are subject to a Federal NSPS (40 CFR Part 60 Subpart IIII for compression ignition engines; 40 CFR Part 60 Subpart JJJJ for spark ignition engines); therefore, these technologies are subject to the Subpart 201-6 Title V operating permit regulations.

- Subpart ZZZZ – Reciprocating Internal Combustion Engine;
- New York State CO₂ Performance Standards (6 NYCRR Part 251); and
- New Source Review (6 NYCRR Part 231).

New stationary combustion sources located in New York State will be required to meet all applicable emissions standards associated with the Federal New Source Performance Standards (NSPS), National Emission Standards for Hazardous Air Pollutants (NESHAP), State air quality regulations/performance standards, and emission limits established through the New Source Review (NSR) permitting process.

NSR pre-construction review/permitting requirements apply to new major sources of regulated NSR air pollutants.¹⁵ A stationary source is classified as major if it directly emits, or has the potential to emit a designated amount of regulated air pollutant or carbon dioxide equivalents (CO₂e) of which the amount depends on the attainment area designation and source type.¹⁶

Currently, New York State has areas designated as non-attainment for ozone, PM_{2.5}, and PM₁₀. The ozone and PM_{2.5} non-attainment areas are shown in the figures below. The only county designated as a PM₁₀ non-attainment area is New York County.¹⁷ In addition, volatile organic carbon (VOC) and nitrogen oxides (NO_x) are treated as non-attainment contaminants statewide as precursors of ozone due to New York State being within the Ozone Transport Region.¹⁸

¹⁵ Regulated NSR air pollutants include: carbon monoxide (CO), lead (Pb), nitrogen oxides (NO_x), sulfur dioxide (SO₂), volatile organic compounds (VOC), and particulate matter with an aerodynamic diameter less than 10 microns (PM₁₀). Regulated NSR contaminant defined in 6 NYCRR §231-4(44).

¹⁶ Major stationary source defined in 6 NYCRR §201-2(21).

¹⁷ Non-attainment area defined in 6 NYCRR §200-1(av).

¹⁸ The term “nonattainment contaminant” is defined in 6 NYCRR §231-4.1 as: “A regulated NSR contaminant emitted by an emission source located or proposed to be located in an area designated in Part 200 of this Title as nonattainment for that contaminant. All of New York State is within the ozone transport region as designated by the act. Therefore, VOC and NO_x are treated as nonattainment contaminants statewide as precursors of ozone. PM_{2.5} precursors, SO₂ and NO_x, are treated as nonattainment contaminants in New York State’s PM_{2.5} nonattainment area.” Ozone Transport Region defined in 6 NYCRR §200.1(bd).

Figure II-1 — Ozone Non-attainment Areas in New York State

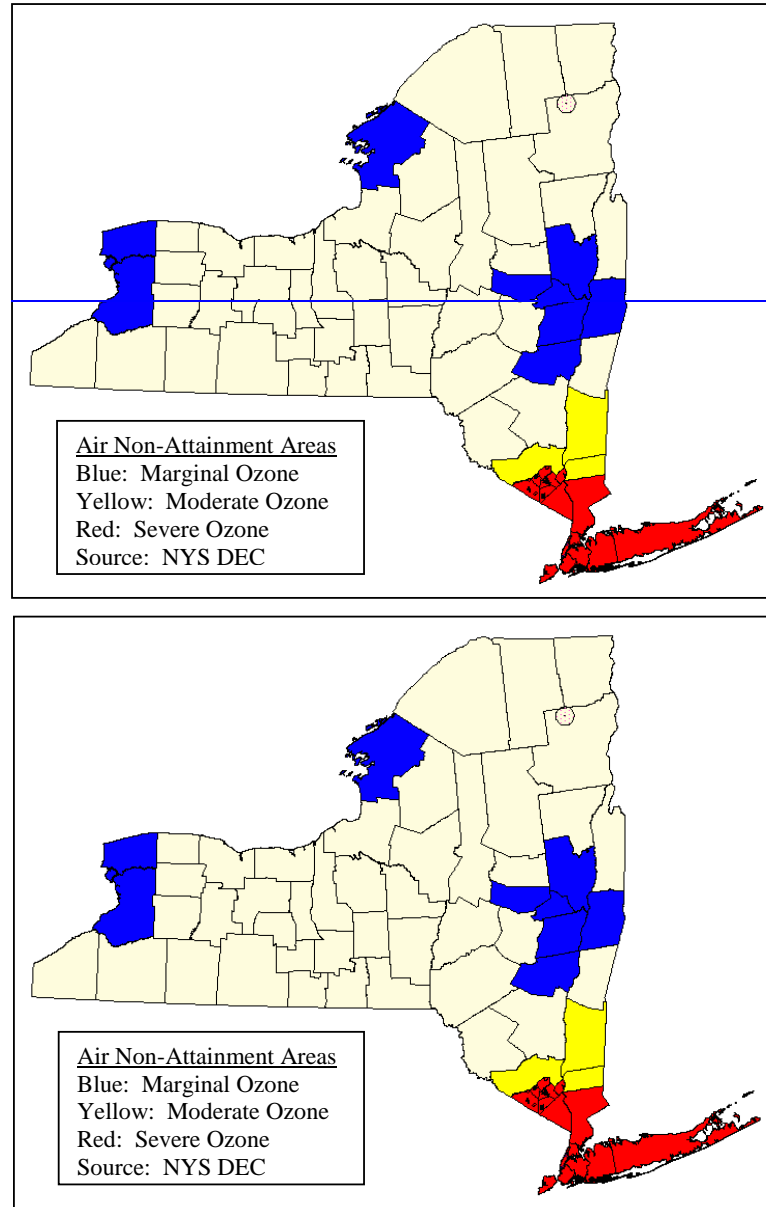
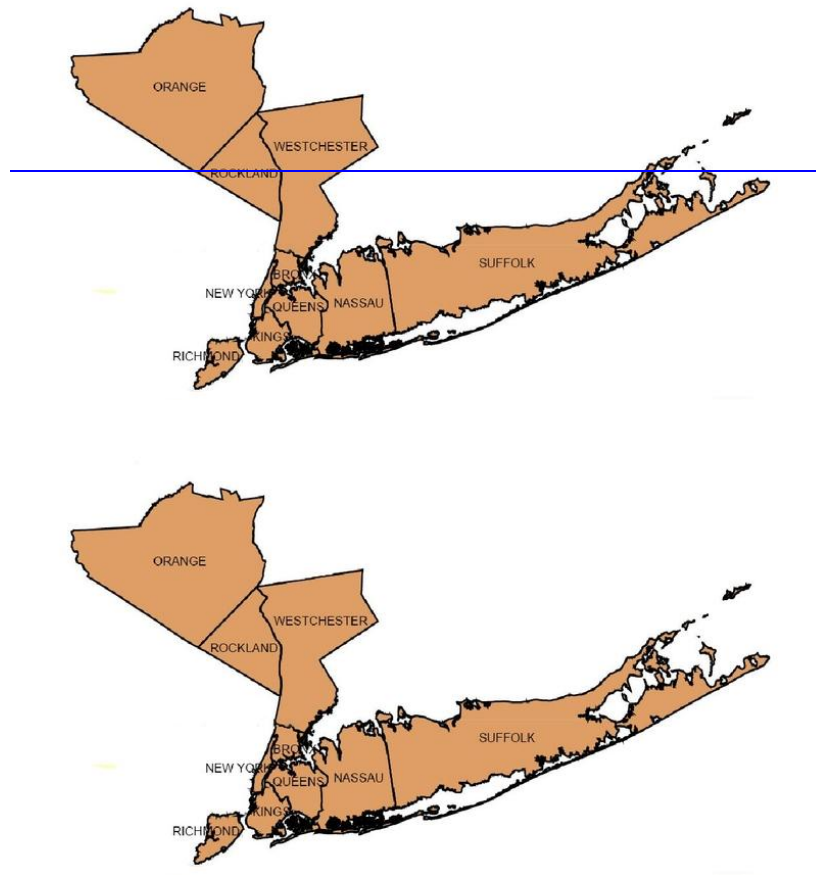


Figure II-2 — PM2.5 Non-attainment Areas in New York State

According to communications with NYDEC, attainment status changes are anticipated in the near-term, including attainment for PM10 and PM2.5 statewide; attainment for marginal and moderate ozone non-attainment areas except Chautauqua County, which will be designated as marginal non-attainment for ozone; and attainment for ozone in lower Orange County. Thus, the anticipated non-attainment areas in the near-term will be severe ozone non-attainment for the New York City Metropolitan Area (i.e., Nassau, Suffolk, Westchester, and Rockland Counties, and all of New York City) and marginal ozone non-attainment for Chautauqua County.¹⁹ Area designations anticipated to be in effect by the end of 2014 were used for the purposes of this report.

As mentioned, a stationary source is classified as major if it directly emits, or has the potential-to-emit, equal to or greater than the major source threshold. The following table provides major

¹⁹ As per correspondence with NYDEC, teleconference with NYDEC and e-mail correspondence with Rob Sliwinski of NYDEC, February 7, 2013.

source thresholds in New York State for new combustion turbines and RICE units within each attainment area designation anticipated in the near-term.²⁰

Table II-2 Major Source Thresholds (tons per year) for New Combustion Turbines and RICE Units in New York State According to Area Designation Expected in the Near-Term

Regulated Air Pollutant	Simple-Cycle CT or RICE			Combined-Cycle CT		
	Severe Ozone NA Area	Marginal Ozone NA Area	AA in Ozone Transport Region	Severe Ozone NA Area	Marginal Ozone NA Area	AA in Ozone Transport Region
VOC	≥ 25	≥ 50	≥ 50	≥ 25	≥ 50	≥ 50
NOx	≥ 25	≥ 100	≥ 100	≥ 25	≥ 100	≥ 100
SO ₂	≥ 250	≥ 250	≥ 250	≥ 100	≥ 100	≥ 100
PM ₁₀	≥ 250	≥ 250	≥ 250	≥ 100	≥ 100	≥ 100
PM _{2.5}	≥ 250	≥ 250	≥ 250	≥ 100	≥ 100	≥ 100
CO	≥ 250	≥ 250	≥ 250	≥ 100	≥ 100	≥ 100
CO _{2e}	≥ 100,000	≥ 100,000	≥ 100,000	≥ 100,000	≥ 100,000	≥ 100,000

All three technologies will exceed the 100,000 tons per year (tpy) CO_{2e} major source threshold without implementing significant operating hour restrictions; therefore, all technologies will be classified as a major source of emissions and subject to NSR permitting. There are two types of NSR permitting requirements: (1) Prevention of Significant Deterioration (PSD) permits and (2) Non-attainment NSR (NNSR) permits.²¹ Since VOC and NOx are treated as non-attainment contaminants statewide, proposed facilities may be required to comply with both the PSD requirements for attainment pollutants and NNSR requirements for non-attainment contaminants.

New major stationary sources in New York State are required to comply with NNSR requirements for each non-attainment contaminant for which the facility exceeds the associated major source threshold. NNSR regulations require the applicant to:

²⁰ Major source thresholds provided in major stationary source definition in 6 NYCRR §201-2(21) and 6 NYCRR §231-13 Tables and Emission Thresholds.

²¹ See, NYCRR §231-7 for PSD regulations and 6 NYCRR §231-5 for NNSR regulations for new facilities.

1. obtain a permit prior to beginning construction of the new source;
2. conduct an analysis of alternative sites, sizes, production process, and environmental control techniques which demonstrates that benefits of the proposed new facility significantly outweigh the potential environmental and social cost;
3. conduct a Lowest Achievable Emission Rates (LAER) analysis and install emission control technology capable of achieving LAER;²² and
4. obtain emission reduction credits (ERC).

Emission reduction credits (ERC) are required for each non-attainment contaminant for which the facility exceeds the associated major source threshold.²³ ERCs must represent the same regulated air pollutant requiring the ERC and derive from within the non-attainment area in which the proposed new facility will be located.²⁴ ERCs of VOC and NO_x for facilities located in an attainment area within the Ozone Transport Region may be obtained from any location within the Ozone Transport Region.²⁵ Facilities in severe ozone non-attainment areas are required to obtain ERCs at an emission offset ratio of 1.3:1 (ratio of required ERCs to the facility's potential-to-emit). Facilities in marginal attainment areas or attainment areas within the Ozone Transport Region are required to obtain ERCs at an emission offset ratio of 1.15:1.²⁶

New major stationary sources in New York State are required to comply with PSD regulations for each regulated air pollutant for which the facility exceeds the significant emissions threshold, excluding non-attainment contaminants required to comply with NNSR requirements. PSD regulations require the applicant to:

1. obtain a permit prior to beginning construction of the new source;

²² LAER is defined in 6 NYCRR §200 as: "The most stringent emission limitation achieved in practice, or which can reasonably be expected to occur in practice for a category or emission sources taking into consideration each air contaminant which must be controlled. In no event shall the application of this term permit a proposed new source or modification to emit any air contaminant in excess of the amount permitted under any applicable emissions standard established under 6 NYCRR or 40 CFR."

²³ Emission reduction credit is defined in 6 NYCRR §231-4(18).

²⁴ ERCs may also be obtained from other non-attainment areas of equal or higher classification, if emissions from such area contribute to a violation of the NAAQS for the regulated air pollutant in the non-attainment area of the proposed facility.

²⁵ Provided that an interstate reciprocal trading agreement is in place. See, 6 NYCRR §231-5.

²⁶ Emission offset is defined in 6 NYCRR §231-4(17). See, 6 NYCRR §231-13 Tables and Emission Thresholds.

2. prepare an ambient air quality impact analysis to determine whether emissions from the proposed project will cause or contribute to a violation of the applicable NAAQS or PSD increments;
3. conduct a Best Available Control Technology (BACT) review and install emission control technologies that represent BACT;²⁷ and
4. provide an additional impact analysis, which includes an analysis of the potential impairment to visibility, soils, and vegetation as a result of the proposed new facility, as well as the potential general commercial, residential, industrial, and other growth associated with the proposed new facility.

The following table provides PSD significant emissions thresholds in New York State for all three technologies within each attainment area designation anticipated in the near-term.²⁸

Table II-3 PSD Significant Emissions Thresholds for All Three Technologies (tons per year) in New York State According to Area Designation Expected in the Near-Term

Regulated Air Pollutant	Severe Ozone NA Area	Marginal Ozone NA Area	AA in Ozone Transport Region
VOC	≥ 2.5	≥ 40	≥ 40
NO _x	≥ 2.5	≥ 40	≥ 40
SO ₂	≥ 40	≥ 40	≥ 40
PM ₁₀	≥ 15	≥ 15	≥ 15
PM _{2.5}	≥ 10	≥ 10	≥ 10
CO	≥ 100	≥ 100	≥ 100
CO _{2e}	≥ 100,000	≥ 100,000	≥ 100,000

²⁷ BACT is defined in 6 NYCRR §200 as: “an emission limitation based on the maximum degree of reduction of each air pollutant emitted from a stationary air emissions source which the NYDEC determines is achievable for such source on a case-by-case basis considering: (1) process, fuels, and raw material available and to be used; (2) engineering aspects of the application of various types of control technology which has been adequately demonstrated; (3) process and fuel changes; (4) respective costs of the application of all such control technologies, process changes, alternative fuels, etc.; and (5) applicable state and federal emission standards.”

²⁸ See, 6 NYCRR §231-13 Tables and Emission Thresholds.

BACT controls are generally considered to be somewhat less stringent than LAER; however, in no event can the application of BACT result in emissions of any air pollutant that will exceed the emissions allowed by any applicable standard (*e.g.*, NSPS, NESHAP, New York State CO₂ Performance Standard).

Based on preliminary emissions calculations for each of the three technologies, the following lists the potential NSR permitting review outcomes. Simple- and combined-cycle combustion turbines will likely trigger PSD/BACT for CO₂e and NO_x emissions, and may trigger PSD/BACT for VOC emissions and NNSR/LAER for NO_x emissions in severe ozone non-attainment areas. RICE units will likely trigger PSD/BACT for CO₂e and NO_x emissions and NNSR/LAER for VOC emissions, and may trigger NNSR/LAER for NO_x emissions in severe ozone non-attainment areas.

New units subject to NSR are required to install air pollution controls and meet unit-specific emission limits established during the NSR review process. LAER/BACT permitting requirements for simple- and combined-cycle combustion turbines will likely require combustion controls (*i.e.*, dry low-NO_x combustors, water injection) and post-combustion controls (*i.e.*, Selective Catalytic Reduction (SCR)) to reduce NO_x emissions and an Oxidation Catalyst (OC) to reduce VOC and carbon monoxide (CO) emissions. High efficiency simple- and combined-cycle combustion turbines should be considered BACT for greenhouse gases (GHG) (*i.e.*, CO₂e). Combustion turbines subject to PSD review for GHG emissions may be required to evaluate the availability of more efficient combustion turbine alternatives. No add-on CO₂ capture and sequestration control technologies have been required to meet the GHG BACT requirements. Potential LAER/BACT emission limits for natural gas-fired simple- and combined-cycle combustion turbines are provided in the table below.

Table II-4 Potential LAER/BACT Requirements for Natural Gas-Fired Simple- and Combined-Cycle Combustion Turbines²⁹

Regulated Air Pollutant	LAER	BACT
NO _x	Selective Catalytic Reduction < 3.0 ppmvd @ 15% O ₂	Selective Catalytic Reduction 3.0 – 5.0 ppmvd @ 15% O ₂
CO / VOC	Oxidation Catalyst ~ 3.0 ppmvd @ 15% O ₂ / ~ 1.0 ppmvd @ 15% O ₂	Oxidation Catalyst 3.0 – 9.0 ppmvd @ 15% O ₂ / ~ 1.5 – 3.0 ppmvd @ 15% O ₂
PM ₁₀	N/A	low ash fuel 0.005 – 0.01 lb/MMBtu
CO ₂ e	N/A	cycle efficiency & NYCRR Part 251

LAER/BACT permitting requirements for RICE units will likely require combustion controls (i.e., engines with low emission combustion (LEC) and/or ignition timing retard technologies) and post-combustion controls (i.e., SCR) to reduce NO_x emissions and an OC to reduce VOC and CO emissions. High efficiency RICE units should be considered BACT for GHGs. RICE units subject to PSD review for GHG emissions may be required to evaluate the availability of more efficient engines. No add-on CO₂ capture and sequestration control technologies have been required to meet the GHG BACT requirements. All RICE units must comply with project-specific NSPS NO_x, VOC, and CO emission limitations.

In addition to implementing emissions control technologies and emissions limitations, short-term related operating restrictions may also be required as a result of meeting the 1-hour NO₂ NAAQS demonstrated by the PSD ambient air quality impact analysis. Potential examples of operating restrictions include: staggered start, start-up and shut-down duration limits (e.g., rapid start requirements), and requirements for taller stack heights.

²⁹ Based on RBLC Database search under Process Code 15.100 (Simple-Cycle Combustion Turbine > 25 MW) and Process Code 15.200 (Combined-Cycle Combustion Turbine > 25 MW). Control technologies for dual fuel-fired combustion turbines are expected to be the same as those required for natural gas-fired units; however, the respective LAER and BACT emission limits may be somewhat higher when firing fuel oil.

D. Cap-and-Trade Program Requirements

New stationary combustion sources in New York State are also subject to cap-and-trade program requirements including:

- CO₂ Budget Trading Program (6 NYCRR Part 242); and
- Clean Air Interstate Rule (CAIR) Trading Program
 - CAIR NO_x Ozone Season Trading Program (6 NYCRR Part 243)
 - CAIR NO_x Annual Trading Program (6 NYCRR Part 244)
 - CAIR SO₂ Trading Program (6 NYCRR Part 245).

In general, the CO₂ Budget Trading Program regulations apply to any fossil fuel-fired unit that serves a generator with a nameplate capacity equal to or greater than 25 MW and generates electricity for sale.³⁰ Part 242 establishes the cap-and-trade provisions pursuant to the Regional Greenhouse Gas Initiative (RGGI), a nine-state cooperative effort to reduce greenhouse gas emissions from electrical generating facilities by means of a cap-and-trade program. Under RGGI, each participating state have committed to state regulations that will cap and then reduce the amount of the CO₂ that electrical generating facilities are allowed to emit. CO₂ allowances are obtained through a CO₂ Allowance Auction system and are traded using CO₂ Budget Trading Programs. The latest CO₂ Allowance Auction, held ~~December 5, 2012~~ on March 15, 2013, sold ~~19,774,000~~ 37,835,405 CO₂ allowances with a clearing price of ~~\$1.932.80~~. Allowances sold ~~represented 53~~ represent 100% of the allowances offered for sale by the nine ~~participating~~ states.

Owners/operators of each CO₂ budget source and CO₂ budget units at the source will be required to obtain CO₂ allowances no less than the total CO₂ emissions from the CO₂ budget units at the source and abide by monitoring, recordkeeping, reporting, and additional requirements described in Part 242. On February 7, 2013, RGGI released a new model rule that now requires owners/operators to hold allowances to cover 50% of emissions for the first two years of each three-year control period (i.e., interim period). Owners/operators must hold allowances to cover 100% of emissions at the end of the three-year control period. The rule also reduced the Regional Emissions Cap to 91 million tons (down from 165 million tons) beginning in 2014 with the original 2.5% per year

³⁰ See, NYCRR §242-1.4.

reduction to the regional RGGI cap for the years 2015 through 2020. The new rule will not take effect until NYS adopts regulations to approve the changes in Part 242, which is expected by the end of ~~2014~~2013.

In general, Parts 243, 244, and 245 CAIR regulations apply to any stationary fossil fuel-fired boiler or combustion turbine that serves a generator with a nameplate capacity equal to or greater than 25 MW producing electricity for sale, and any other electrical generating unit that serves a generator with a nameplate capacity of equal to or greater than 15 MW producing electricity for sale.³¹

CO₂, NO_x, and SO₂ allowances are included in the economic dispatch. The cost of ERCs is included in the capital cost-estimates in these zones to allow for unrestricted operating hours in accordance with economic dispatch.

E. Other Permitting Requirements

Additional regulations that will impact permitting, air emissions, and facility design for all new stationary combustion sources includes 6 NYCRR Part 487 and NYDEC Policy CP-#52.

6 NYCRR Part 487 establishes a regulatory framework for undertaking an analysis of environmental justice issues associated with siting of major electric generating facilities pursuant to Public Service Law Article 10. Public Service Law Article 10 requires any proposed electric generating facilities with a nameplate generating capacity of 25 MW or more to obtain a Certificate of Environmental Compatibility and Public Need. Part 487 provides regulations to implement the environmental justice provisions of Public Service Law Article 10.

Regulations provided in Part 487 are intended to enhance public participation and review of environmental impacts of proposed major electric generating facilities that affect environmental justice areas and reduce disproportionate environmental impacts in overburdened communities. These regulations establish how an applicant must undertake an environmental justice analysis, including the requirements for (i) an evaluation of significant and adverse disproportionate environmental impacts of the proposed facility, if any, resulting from its construction or operation, including (ii) a cumulative impact analysis of air quality, and (iii) a comprehensive demographic,

³¹ See, NYCRR §243-1.4, §244-1.4, §245-1.4 42, and 42 U.S.C. Section 7651a(2).

economic and physical description of the community within which the facility will be located, compared and contrasted to the county and adjacent communities. Specific analysis requirements would have to be evaluated on a case-by-case basis.

Proposed new facilities in New York State with cooling water intake structures that are in connection with point source thermal discharges may also be impacted as per NYDEC Policy CP-#52. ~~Proposed new facilities designed to withdraw equal to or greater than 20 million gallons per day (MGD) of water, where at least 25% is used for contact or non-contact cooling, are required to install cooling water intake structures that reflect the best technology available (BTA) to minimize adverse environmental impacts.~~ NYDEC Policy CP-52 ~~designates~~ seeks a performance goal of dry closed-cycle cooling ~~systems as BTA~~ for all new industrial facilities sited in the marine and coastal district;³² ~~which includes waters of the Atlantic Ocean~~ and the Hudson River up to the Federal Dam in Troy; ~~and irrespective of the amount of water they would withdraw for cooling if they were to use a~~ wet closed-cycle cooling ~~systems as BTA for new facilities located along all other New York State waters.~~

~~Based on preliminary performance calculations for the three technologies, the estimated maximum withdrawal is approximately 2.3 MGD for wet closed cycle cooling of the combined cycle technology. Water withdrawal for the simple cycle and reciprocating engine technologies is significantly less than 2.3 MGD. As per correspondence with NYDEC, "new facilities withdrawing less than 20 MGD in the marine district [NYDEC] would require closed cycle cooling, but not necessarily dry cooling. It would be site specific."~~³³ ³⁴ As a result, wet closed-cycle cooling systems were assumed for all technologies in Zone C and dry closed-cycle cooling systems were assumed for all technologies in Zone J and ~~wet closed-cycle cooling systems were assumed for all technologies in~~ the remaining locations. {NTD: In this report, the cost and performance of the LMS100 and 18V50 technologies, and the capital cost of the SGT6-F5000(5) combined cycle technology, include the effects of dry cooling. The performance of the SGT6-F5000(5) combined

³² ~~The marine and coastal district includes the waters of the Atlantic Ocean within three nautical miles from the coast line and all other tidal waters within New York State. See, ECL §13-0103.~~

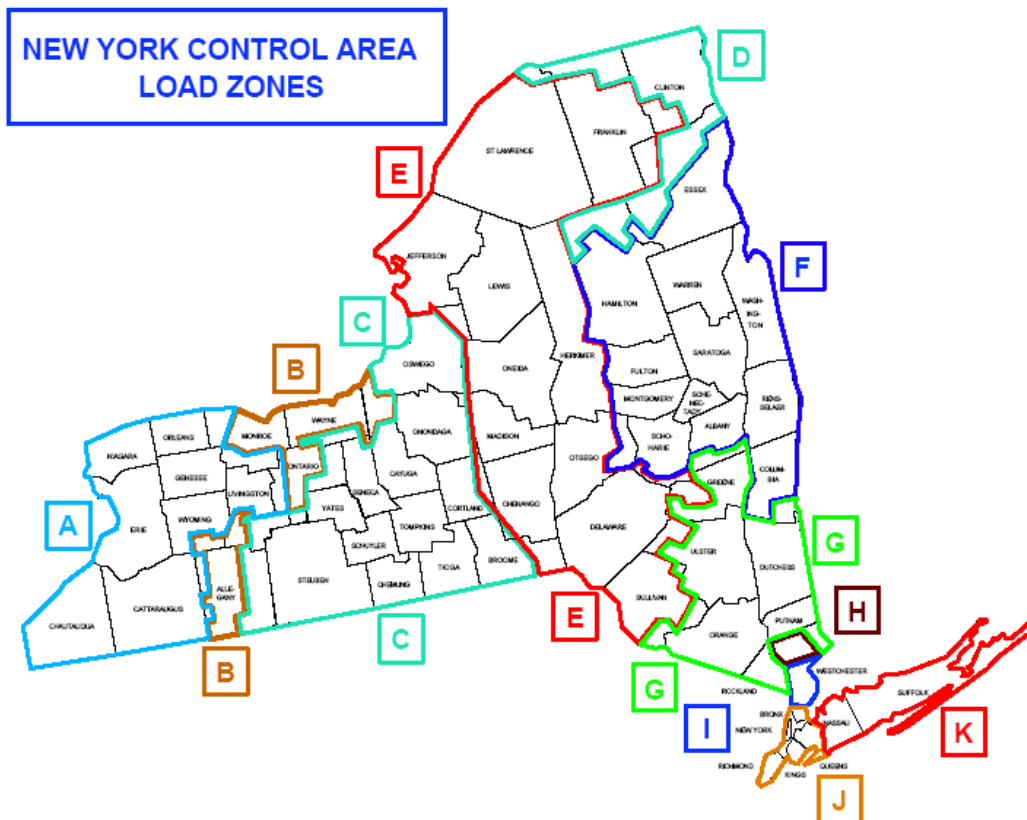
³³ ~~The marine and coastal district includes the waters of the Atlantic Ocean within three nautical miles from the coast line and all other tidal waters within New York State. See, ECL §13-0103.~~

³⁴ As per e-mail correspondence with ~~Rob Sliwinski, Director~~ Chuck Nieder, Steam Electric Unit Leader, Bureau of Air Quality Planning, Division of Air Resources, of Habitat, NYDEC, ~~February 12~~ April 30, 2013.

cycle technology have not been updated for dry cooling and will be provided in the next version of this report.] All technologies must also comply with the requirements of the federal Clean Water Act Section 316(b) for cooling water intake structures.

F. Construction Schedule and Costs

Cost estimates were prepared for the construction of each of the three technologies in each of five New York load zones: C, F, G, J, and K. -Figure II-2 shows the location of these zones. The estimates include two locations within Zone G (Poughkeepsie in Dutchess County and Suffern in Rockland County) to account for the higher cost of labor cost and greater amounts of Emissions Reductions Credits needed for some technologies in the southern portion of the zone. The Rockland County location is in the New York City Metropolitan Area and an ozone non-attainment area.



These estimates reflect plant features typically found in new peaking facilities and are intended to reflect representative costs for new plants of their type, in year 2013 dollars. The estimates are conceptual and are not based on preliminary engineering activities for any specific site. The estimates reflect projects awarded on an Engineering, Procurement, and Construction (EPC) basis, with combustion turbines and emissions control systems purchased directly by the owner. The scope includes all site facilities for power generation and distribution, including a ~~345-kV switchyard (138-kV switchyard in New York City and Long Island)~~ [NTD costs for switchyard in the Long Island cases shown in the tables of this draft are based on a 345-kV switchyard; will be revised] and interconnection costs. ~~[NTD: Interconnection cost estimates are under development and are not included in the estimates in this draft of the report; will be included later.]~~ switchyard and interconnection costs.

1. Principal Assumptions

The key assumptions are discussed below.

a. Technology and Emissions Controls

Pursuant to the discussion in the previous section, estimates were prepared using Siemens SGT6-PAC5000F(5) – 1x1x1 combined-cycle combustion turbine (1 unit), General Electric LMS100-PA simple-cycle combustion turbines (2 units), and Wartsila 18V50SG reciprocating internal combustion engines (12 units) with an SCR and Oxidation Catalyst in all zones.

Selective Catalytic Reduction is a post-combustion control technology in which injected ammonia reacts with NO_x in the presence of a catalyst to form water vapor and nitrogen. The geometric configuration of the catalyst body is designed for maximum surface area and minimum back-pressure on the combustion turbine. An ammonia injection grid is located upstream of the catalyst body and is designed to disperse ammonia uniformly throughout the exhaust flow before it enters the catalyst unit. The level of NO_x emission reduction is a function of the catalyst volume, ammonia-to-NO_x (NH₃/NO_x) ratio, and flue gas temperature.

Selective Catalytic Reduction is a widely accepted post-combustion control technology for combined-cycle combustion turbines, and is becoming more common on simple-cycle combustion turbines. Selective Catalytic Reduction on a combined-cycle unit consists of a passive reactor located in the heat recovery steam generator (HRSG) in an area where flue gas temperatures support the NH₃/NO_x reduction reactions. Selective Catalytic Reduction on simple-cycle units can be more complicated, as tempering air may be needed to reduce the temperature of the combustion turbine exhaust to the levels required for NO_x control. Selective Catalytic Reduction on a simple-cycle unit consists of a passive reactor located downstream of the tempering air and catalytic oxidation systems, if present.

Catalytic oxidation system is a post-combustion control technology that has been designed for use on simple- and combined-cycle units. A catalytic oxidation system on a simple-cycle unit consists of a passive reactor located immediately downstream of the combustion turbine exhaust. Catalytic oxidation control on a combined-cycle unit consists of a passive reactor located in the HRSG within the temperature window required for CO/VOC control. The reactor vessel is fitted with a honeycomb grid of metal panels coated with a precious metal catalyst (usually platinum, palladium, or rhodium). Exhaust gas passes over the catalyst surface, promoting the oxidation reaction of CO + ½O₂ → CO₂. This reaction occurs spontaneously without the need to inject reactants, such as ammonia, into the exhaust gas.

b. Site Conditions

In all zones except Zone J, the study is based on greenfield site conditions to incorporate all of the normally expected costs to develop a new entrant peaking plant. Land and water requirements for greenfield conditions are summarized in Table II-5 and Table II-1, respectively. Although brownfield sites exist, there are a limited number in these zones

In Zone J, greenfield site conditions are rarely found and brownfield sites are the norm for new generating facilities. For this study, it is assumed that an existing generating or industrial site would be developed, but that no common facilities were available for use. Costs were included to remove existing structures and provide for site remediation of contaminated soils.

c. Inlet Air Cooling

Inlet air evaporative cooling was assumed for all gas turbine technologies because it increases overall capacity for operation in hot ambient conditions. Evaporative cooling does not increase power production for reciprocating internal combustion engines. Wet cooling was assumed for the intercooler for the LMS100 in all zones except zone J which assumes dry cooling. Inlet air chillers were not included in the configuration due to cost considerations.

d. Dual vs. Single Fuel

The capability to burn natural gas or fuel oil reduces the risk of not having peaking capacity available, when needed, due to fuel supply interruption, and adds capital cost while lowering operating costs. However, current NYISO rules do not require dual-fuel capability. Gas availability is more likely a problem in the winter when reliability is less an issue. In New York City, Consolidated Edison Service Classification No. 9 appears to require dual fuel capability to qualify for Power Generation Transportation Service.³⁵ [On Long Island, National Grid \(formerly Keyspan\) Service Classification No. 14 appears to limit eligibility for gas transportation service for electric generation to dual fuel electric generators having capacity of at least 50 MWs.](#)³⁶ Given that obtaining new firm gas transportation is prohibitively expensive ~~in New York City~~, a new peaking

³⁵ Consolidated Edison Company of New York, Inc. (Con Edison), Service Classification No. 9, Transportation Service (TS), Leaf 266.

³⁶ [Keyspan Gas East Corporation, DBA Brooklyn Union of Long Island, Service Classification No. 14, Electric Generation Service, Leaf 187. Firm gas transportation is also available under this tariff if feasible, and the cost of system improvements is covered by the generator.](#)

unit ~~in New York City~~ would realistically have this capability; therefore, dual fuel capability has been assumed for ~~Zone~~Zones G, J, and K. *[NTD: The cost of dual fuel capability for the three technologies in Zones G and J is provided in this report. The cost of dual fuel capability in Zone K will be included in the next revision of the report]* Firing only with natural gas was assumed for ~~Long Island (Zone K) and~~ the balance of the NYCA.

e. Gas Compression

Fuel gas compressors have been included based on a local supply pressure of 250 psig in New York City and 450 psig elsewhere.

f. Contingency

Contingency is added to cover undefined variables in both scope definition and pricing that are encountered within the original scope parameters. Contingency should always be treated as “spent money.” Examples of where it is applied would include nominal adjustments to material quantities in accordance with the final design, items clearly required by the initial design parameters that were overlooked in the original estimate detail, and pricing fluctuations like the run-up in copper prices. A contingency of 10% was applied to the total of direct and indirect project costs, which is consistent with industry custom and practice, is typical for construction projects of this type.

g. Basis for Equipment, Materials, and Labor Costs

All equipment and material costs are based on S&L in-house data, vendor catalogs, or publications. Labor rates have been developed based on union craft rates in 2010.³⁷ Costs have been added to cover FICA, fringe benefits, workmen’s compensation, small tools, construction equipment, and contractor site overheads. Work is assumed to be performed on a 50-hour work week by qualified craft labor available in the plant area. Labor rates are based on Onondaga County for Zone C, Albany County for Zone F, Dutchess County and Rockland County for Zone G, New York County for Zone J, and Suffolk County for Zone K. An allowance to attract and keep labor was included. A labor productivity adjustment of 1.40 has been applied to Zone J, 1.35 for Zone K and 1.10 for

³⁷ Base pay and supplemental (fringe) benefits were obtained from the Prevailing Wage Rate Schedules – New York State Department of Labor using the latest available data as of ~~March 2010~~[February 2013](#).

other zones.³⁸ Materials costs are based on data for Syracuse in Zone C, Albany in Zones F and G, New York City in Zone J, and Riverhead in Zone K.

h. Interconnection Costs

Interconnection costs are comprised of System Deliverability Upgrades (SDU) and Minimum Interconnection Standard (MIS) costs. NYISO staff analyzed the deliverability of up to 400 MWs at eight points of interconnection (POI) that were representative of locations available for capacity additions in Zones F, G, J and K. NYISO identified no SDUs for the capacity levels of the LMS100 and Wartsila technologies. *[NTD: The need for and cost of SDUs for the SGT6-5000F(5) – 1x1x1 combined-cycle technology is not available and will be included in the next draft].*

MIS costs were based on the sum of individual estimates of the following component cost categories: 1- Electrical System Upgrade Facilities (SUF); 2) Protection SUFs; 3) Headroom payments; and 4) Connecting Transmission Owner (CTO) Attachment Facilities (AF). Costs for Protection SUFs, Headroom payments, and CTO AFs were based on an average of these costs for representative projects from class year (CY) studies for CY09, CY10 and CY11. Costs for Electrical SUFs were based on the cost to expand the substation at the point of interconnection (POI). The type (open air or gas insulated) and voltage (138 kV, 230 kV or 345 kV) of each substation were the same as the POIs analyzed in NYISO deliverability studies. S&L used the same cost estimating assumptions as for each generating technology, with the exception of the contingency. A contingency of 20 percent was assumed for interconnection because, in addition to expected uncertainties due to price variations in labor, materials and equipment, and adjustments in materials quantities, the site conditions, configuration of the existing substation equipment, and specific equipment configuration needed for interconnection, are uncertain.

h.i. Miscellaneous

Black start capability has not been included because NYISO offers a proxy payment to black start generators, or a generator can submit its actual costs for reimbursement. Pile foundations were assumed for Zone J because most available sites are along the East River. Spread footing foundations were assumed elsewhere. Use of rental trailer-mounted water treating equipment was assumed. Potable water is available from a municipal supply. Wastewater treatment is not

³⁸ Based on ranges obtained from the 2010 Global Construction Cost Yearbook published by Compass International.

included; contaminated wastewater will be collected locally for tanker truck disposal. A control/administration building is included.

2. Capital Investment Costs

Capital investment costs for each peaking unit option include direct costs, owner's costs, financing costs during construction, and working capital and inventories:

- Direct costs are costs typically within the scope of an EPC contract. These costs are estimated in detail in Appendix 1.
- Owner's costs include items not covered by the EPC scope such as development costs, oversight, legal fees, financing fees, startup and testing, and training. On the basis of data extracted from recent independent power projects, these costs have been estimated as 9% of direct capital costs, plus the cost of ERCs. In addition, social justice costs were estimated to be 0.9% of EPC costs in New York City and 0.2% of EPC costs elsewhere;
- ERC's were included in the owner's costs for the LMS100 in Zones J and K, for the SGT6-5000F(5) in Zones F, G, J, and K, and for the 18V50DF/18V50SG in Zones C, G, F, and J. ERCs are based on no restrictions in annual operating hours and an allowance for startup and shutdown emissions based on one startup per week day.³⁹ For dual fuel units, ERCs include 30 days per year of Ultra Low Sulfur Diesel fuel operation and 11 months of natural gas operation.
- Financing costs during construction refer to the cost of debt and equity required over the periods from each construction expenditure date through the plant in-service date. These costs have been calculated from the monthly construction cash flows associated with the capital cost estimates in Appendix 1, and the cost of debt and equity presented in Section IV.B. For the LMS100, a 20-month construction period is assumed, with cash flows peaking in the 14th month. For the SGT6-5000F(5) combined cycle, a 39-month construction period is assumed, with cash flows peaking in the 28th month. For the

³⁹ GE LMS100 = 260 start-ups and 260 shut-downs; Siemens 1x1x1 combined cycle = 8 cold start-ups, 52 warm start-ups, 200 hot start-ups and 260 shut-downs; Wartsila engines = 8 cold start-ups, 252 warm start-ups and 260 shut-downs.

18V50DF/18V50SG, a 24-month construction period is assumed, with cash flows peaking in the 20th month. In each case, over 70% of the total cash flow occurs in the second half of the construction period.

- Working capital and inventories refer to the initial inventories of fuel, consumables, and spare parts that are normally capitalized. It also includes working capital cash for the payment of monthly operating expenses. On the basis of recent independent power projects, these costs have been estimated as 2% of direct capital costs. [In the case of dual fuel, this amount includes an inventory of Ultra Low Sulfur Diesel fuel equivalent to 2.5 - 3.5 days of full load operation priced at \\$25/mmBtu.](#)

Capital investment costs for each location and combustion turbine option are summarized below in **Error! Reference source not found.**Table II-5.

Table II-5 — Capital Investment Costs for Greenfield Site (2013 \$)

	2xGE LMS100 PA	1x1x1 Siemens SGT6-5000(F)	12xWartsila 18V50
Zone C - Syracuse			
Direct Costs	203,836,000	322,413,000	300,962,000
Owner's Costs	18,753,000	30,891,000	32,989,000
Financing Costs During Construction	10,397,000	33,253,000	15,391,000
Working Capital and Inventories	4,077,000	6,448,000	6,019,000
Total	237,063,000	393,005,000	355,361,000
Net Degraded ICAP MW	186.25	301.67	197.94
\$/kW	\$1,273	\$1,303	\$1,795
Zone F - Albany			
Direct Costs	206,628,000	329,639,000	305,895,000
Owner's Costs	19,009,000	32,706,000	32,622,000
Financing Costs During Construction	10,540,000	34,104,000	15,603,000
Working Capital and Inventories	4,133,000	6,593,000	6,118,000
Total	240,310,000	403,042,000	360,238,000
Net Degraded ICAP MW	187.414	303.24	188.30
\$/kW	\$1,282	\$1,329	\$1,913

	2xGE LMS100 PA	1x1x1 Siemens SGT6-5000(F)	12xWartsila 18V50
Zone G - Hudson Valley (Dutchess County)			
Direct Costs	215,313,000	356,197,000	322,556,000
Owner's Costs	19,809,000	35,150,000	34,156,000
Financing Costs During Construction	10,982,000	36,833,000	16,441,000
Working Capital and Inventories	4,306,000	7,124,000	6,451,000
Total	250,410,000	435,304,000	379,604,000
Net Degraded ICAP MW	188.256	303.81	188.30
\$/kW	\$1,330	\$1,433	\$2,016
Zone G - Hudson Valley (Rockland County)			
Direct Costs	221,049,000	370,850,000	331,689,000
Owner's Costs	20,335,000	36,500,000	34,995,000
Financing Costs During Construction	11,275,000	38,339,000	16,901,000
Working Capital and Inventories	4,421,000	7,417,000	6,634,000
Total	257,080,000	453,106,000	390,219,000
Net Degraded ICAP MW	188.256	303.81	188.30
Net Degraded ICAP Heat Rate (Btu/kWh)	9,331	9,332	9,335
\$/kW	\$1,366	\$1,491	\$2,072

	2xGE LMS100 PA	1x1x1 Siemens SGT6-5000(F)	12xWartsila 18V50
Zone J - NYC			
Direct Costs	275,910,000	477,757,000	407,739,000
Owner's Costs	28,455,000	50,079,000	46,606,000
Financing Costs During Construction	14,217,000	49,679,000	20,941,000
Working Capital and Inventories	5,518,000	9,555,000	8,155,000
Total	324,100,000	587,070,000	483,441,000
Net Degraded ICAP MW	184.00	303.89	188.30
\$/kW	\$1,761	\$1,932	\$2,567
Zone K - Long Island			
Direct Costs	240,997,000	425,232,000	369,520,000
Owner's Costs	23,312,000	41,820,000	39,056,000
Financing Costs During Construction	12,346,000	43,959,000	18,831,000
Working Capital and Inventories	4,820,000	8,505,000	7,390,000
Total	281,475,000	519,516,000	434,797,000
Net Degraded ICAP MW	189.394	305.97	188.30
\$/kW	\$1,486	\$1,698	\$2,309

	2xGE LMS100 PA	1x1x1 Siemens SGT6-5000(F)	12xWartsila 18V50
Zone C - Syracuse			
Direct Costs	215,173,000	331,986,000	310,535,000
Owner's Costs	19,796,000	31,774,000	33,871,000
Financing Costs During Construction	10,976,000	34,238,000	15,874,000
Working Capital and Inventories	4,303,000	6,640,000	6,211,000
Total	250,248,000	404,638,000	366,491,000
Net Degraded ICAP MW	186.25	301.67	197.94
\$/kW	\$1,344	\$1,341	\$1,852
Zone F - Albany			
Direct Costs	228,078,000	352,005,000	315,468,000
Owner's Costs	20,983,000	34,764,000	33,520,000
Financing Costs During Construction	11,634,000	36,403,000	16,085,000
Working Capital and Inventories	4,562,000	7,040,000	6,309,000
Total	265,257,000	430,212,000	371,382,000
Net Degraded ICAP MW	183.6	303.24	188.30
\$/kW	\$1,445	\$1,419	\$1,972

Zone G - Hudson Valley (Dutchess County)			
Direct Costs	244,839,000	386,104,000	344,213,000
Owner's Costs	23,871,000	37,902,000	37,186,000
Financing Costs During Construction	12,551,000	39,907,000	17,579,000
Working Capital and Inventories	4,897,000	7,722,000	6,884,000
Total	286,158,000	471,635,000	405,862,000
Net Degraded ICAP MW	184.402	303.81	188.30
\$/kW	\$1,552	\$1,552	\$2,155
Zone G - Hudson Valley (Rockland County)			
Direct Costs	251,140,000	401,319,000	353,487,000
Owner's Costs	24,450,000	39,302,000	38,041,000
Financing Costs During Construction	12,873,000	41,471,000	18,045,000
Working Capital and Inventories	5,023,000	8,026,000	7,070,000
Total	293,486,000	490,118,000	416,643,000
Net Degraded ICAP MW	184.402	303.81	188.30
\$/kW	\$1,592	\$1,613	\$2,213

Zone J - NYC			
Direct Costs	288,480,000	492,940,000	420,748,000
Owner's Costs	29,703,000	51,580,000	48,088,000
Financing Costs During Construction	14,862,000	51,251,000	21,608,000
Working Capital and Inventories	5,770,000	9,859,000	8,415,000
Total	338,815,000	605,630,000	498,859,000
Net Degraded ICAP MW	184.00	303.89	188.30
\$/kW	\$1,841	\$1,993	\$2,649
Zone K - Long Island			
Direct Costs	261,528,000	444,824,000	380,851,000
Owner's Costs	25,205,000	43,623,000	40,097,000
Financing Costs During Construction	13,393,000	45,973,000	19,401,000
Working Capital and Inventories	5,231,000	8,896,000	7,617,000
Total	305,357,000	543,316,000	447,966,000
Net Degraded ICAP MW	185.516	305.97	188.30
\$/kW	\$1,646	\$1,776	\$2,379

G. Other Plant Costs

Other costs associated with each peaking unit option include fixed O&M costs, variable O&M costs, and fuel costs. These costs are estimated in detail in Appendix 1, Table A-2. The basis for these estimates is described in the following subsections.

1. Fixed O&M Costs

Fixed O&M costs include costs directly related to the turbine design (labor, materials, contract services for routine O&M, and administrative and general costs) and other fixed operating costs related to the location (site leasing costs, property taxes, and insurance). Design-related costs were derived from a variety of sources, including the State-of-the-Art Power Plant Combustion Turbine Workstation, v 8.2, developed by the Electric Power Research Institute (EPRI), data for existing plants reported on FERC Form 1, and confidential data from other operating plants. The number of operating staff was estimated based on projected number of operating hours from Section III results. The number of maintenance staff for the LMS100 in Zone J was increased by one FTE due to onsite fuel oil storage requirements. The resulting cost assumptions are summarized in Table II-6.

Table II-6 — Fixed O&M Assumptions (2013 \$)

	Long Island	NYC	ROS
	LMS100 PA	LMS100 PA	LMS100 PA
Average Labor Rate, incl. Benefits (\$/hour)	\$71.40	\$71.40	\$50.10 to \$72.40
Operating Staff (full-time equivalents)	5	5	5
Maintenance Staff (full-time equivalents)	3	4	3
Routine Materials and Contract Services	\$340,000	\$340,000	\$340,000
Administrative and General	\$370,000	\$370,000	\$370,000

	Long Island	NYC	ROS
	PAC5000F(5) 1 x 1 x 1 CC	PAC5000F(5) 1 x 1 x 1 CC	PAC5000F(5) 1 x 1 x 1 CC
Average Labor Rate, incl. Benefits (\$/hour)	\$71.40	\$71.40	\$50.10 to \$72.40
Operating Staff (full-time equivalents)	15	15	15
Maintenance Staff (full-time equivalents)	8	8	8
Routine Materials and Contract Services	\$3,140,000	\$3,140,000	\$3,140,000
Administrative and General	\$620,000	\$620,000	\$620,000

	Long Island	NYC	ROS
	18V50	18V50	18V50
Average Labor Rate, incl. Benefits (\$/hour)	\$71.40	\$71.40	\$50.10 to \$72.40
Operating Staff (full-time equivalents)	6	6	6
Maintenance Staff (full-time equivalents)	6	6	6
Routine Materials and Contract Services	\$1,050,000	\$1,050,000	\$1,050,000
Administrative and General	\$400,000	\$400,000	\$400,000

	Long Island	NYC	Hudson Valley (Dutchess)	Hudson Valley (Rockland)	Albany	Syracuse
	LMS100 PA	LMS100 PA	LMS100 PA	LMS100 PA	LMS100 PA	LMS100 PA
Average Labor Rate, incl. Benefits (\$/hour)	\$86.20	\$88.88	\$74.15	\$75.65	\$56.51	\$52.33
Operating Staff (full-time equivalents)	5	5	5	5	5	5
Maintenance Staff (full-time equivalents)	3	4	3	3	3	3
Routine Materials and Contract Services	\$362,000	\$367,000	\$340,000	\$343,000	\$308,000	\$300,000
Administrative and General	\$394,000	\$399,000	\$370,000	\$373,000	\$335,000	\$326,000

	Long Island	NYC	Hudson Valley (Dutchess)	Hudson Valley (Rockland)	Albany	Syracuse
	1 x 1 x 1 SGT6-5000F(5)	1 x 1 x 1 SGT6-5000F(5)	1 x 1 x 1 SGT6-5000F(5)	1 x 1 x 1 SGT6-5000F(5)	1 x 1 x 1 SGT6-5000F(5)	1 x 1 x 1 SGT6-5000F(5)
Average Labor Rate, incl. Benefits (\$/hour)	\$86.20	\$88.88	\$74.15	\$75.65	\$56.51	\$52.33
Operating Staff (full-time equivalents)	15	15	15	15	15	15
Maintenance Staff (full-time equivalents)	8	8	8	8	8	8
Routine Materials and Contract Services	\$3,344,000	\$3,390,000	\$3,140,000	\$3,165,000	\$2,841,000	\$2,770,000
Administrative and General	\$660,000	\$669,000	\$620,000	\$625,000	\$561,000	\$547,000

	Long Island	NYC	Hudson Valley (Dutchess)	Hudson Valley (Rockland)	Albany	Syracuse
	18V50	18V50	18V50	18V50	18V50	18V50
Average Labor Rate, incl. Benefits (\$/hour)	\$86.20	\$88.88	\$74.15	\$75.65	\$56.51	\$52.33
Operating Staff (full-time equivalents)	6	6	6	6	6	6
Maintenance Staff (full-time equivalents)	6	6	6	6	6	6
Routine Materials and Contract Services	\$1,118,000	\$1,133,000	\$1,050,000	\$1,058,000	\$950,000	\$926,000
Administrative and General	\$426,000	\$432,000	\$400,000	\$403,000	\$362,000	\$353,000

Other fixed operating costs are described below and summarized in Table II-7.

a. Site Leasing Costs

Site leasing costs are equal to the annual lease rate (\$/acre-year) multiplied by the land requirement in acres. The values used for all zones were from the 2010 Demand Curve Reset Study, escalated by inflation. These values are shown in Table II-7.

b. Property Taxes and Insurance

Property taxes are equal to the unadjusted property tax rate for the given jurisdiction, multiplied by an assessment ratio, and multiplied by the market value of the plant. The assessment ratio is the percentage of market value applied in the tax calculation. The property tax rates and assessment ratios for this analysis were selected as typical values currently in effect for jurisdictions in each location, as follows:

NYC: (City of New York website), Class 4 Property (10.288%) x 45% assessment ratio = 4.63% effective rate. Power plant equipment that is not rate regulated by the New York Public Service Commission should be treated as general commercial real property (Class 4).⁴⁰

LI: Each town in Suffolk County sets its own property tax rate.^{41,42} The limit on the effective rate is 1.5% in the county, but villages have a 2.0% limit, and towns have no limit. An effective value of 2.00% was chosen as representative for LI.

ROS: Locations in Rest of State: We examined data from the New York State Office of Real Property Tax Services ((www.tax.ny.gov/research/property) and county websites. From the wide

⁴⁰ In the Matter of Astoria Gas Turbine Power, LLC v. Tax Commission of City of New York, 7 NY3d 451, 857 N.E.2d 510, 824 N.Y.S.2d 189 (2006).

⁴¹ <http://www.osc.state.ny.us/localgov/orptbook/taxrates.htm>

⁴² <http://www.osc.state.ny.us/localgov/orptbook/taxrates.htm>

range of values posted for Ulster County (in the Hudson Valley) and Onondaga County (Syracuse area) on their websites, a typical rate and assessment ratio of: 4.0% and 50%, respectively, were chosen for a 2.00% effective rate.

Under the New York State real property tax exemption law enacted in May 2011, an exemption from property taxes for the first 15 years is available for new peaking units constructed in New York City.⁴³⁴⁴ Real levelized carrying charge rates, which include property taxes and insurance, are provided both with and without the A07511 provisions.

Insurance costs are estimated to be 0.30% of the initial capital investment, escalating each year with inflation, on the basis of actual data for recent independent power projects.

Property taxes and insurance are commonly considered to be part of the carrying charge rate because their value is directly related to the plant capital cost. The carrying charge rates in Section II.F.3 of this report are derived both with and without property taxes and insurance.

Table II-7 — Other Fixed Operating Cost Assumptions (2013 \$)

	NYC	Long Island	ROS
Land Requirement - 2 x LMS100 PA (acres)	6.0	6.0	6.0
Land Requirement - Combined Cycle (acres)	20.00	20.00	20.00
Land Requirement - Reciprocating Engines (acres)	10.00	10.00	10.00
Lease Rate (\$/acre-year)	240,000	23,000	19,000
Property Tax Rate *	10.288%	2.00%	4.00%
Assessment Ratio	45.00%	100.00%	50.00%
Effective Property Tax Rate	4.63%	2.00%	2.00%
Insurance Rate	0.30%	0.30%	0.30%

	NYC	Long Island	Lower Hudson	ROS
Land Requirement - 2 x LMS100 PA (acres)	6.0	6.0	6.0	6.0
Land Requirement - Combined Cycle (acres)	15.00	15.00	20.00	20.00
Land Requirement - Reciprocating Engines (acres)	10.00	10.00	10.00	10.00
Lease Rate (\$/acre-year)	240,000	23,000	19,000	19,000
Property Tax Rate *	10.288%	2.00%	4.00%	4.00%
Assessment Ratio	45.00%	100.00%	50.00%	50.00%
Effective Property Tax Rate	4.63%	2.00%	2.00%	2.00%
Insurance Rate	0.30%	0.30%	0.30%	0.30%

⁴³ Chapter 28 of the Laws of 2011 of New York, amending Title 2-F of Article 4 of the New York Real Property Tax Law.

⁴⁴ Chapter 28 of the Laws of 2011 of New York, amending Title 2-F of Article 4 of the New York Real Property Tax Law.

* The effective property tax rate in NYC excludes the NYC real property tax exemption granted during the first 15 years of operation under Title 2-F of Article 4 of the New York Real Property Tax Law¹.

H. Variable O&M Costs

Over the long-term operating life of a peaking facility, the largest component of variable O&M is the allowance for major maintenance expenses. Each major maintenance cycle for a combustion turbine typically includes regular combustor inspections, periodic hot gas path inspections, and one major overhaul. For the aeroderivative units, a major maintenance overhaul every 50,000 factored operating hours was assumed. For the frame units, major overhauls were assumed to be every 48,000 operating hours or 2,400 factored starts, whichever occurs first. Normal operating hours and normal starts are factored, that is, increased to account for severe operating conditions. For example, operating hours are factored for operation on fuel oil instead of natural gas and starts are factored as a result of trips or emergency starts. For peaking duty, major maintenance intervals thus tend to be hours-based for the aeroderivative units and starts-based for the frame units.

Since major maintenance activities and costs are spaced irregularly over the long-term, the cost in a given year represents an annual accrual for future major maintenance. For hours-based maintenance, the average major maintenance cost in \$/MWh is equal to the total cost of parts and labor over a complete major maintenance interval divided by the factored operating hours between overhauls, divided by the unit capacity in megawatts. For starts-based maintenance, the average major maintenance cost in \$/factored start is equal to the total cost of parts and labor over a complete major maintenance interval divided by the factored starts between overhauls.

Other variable O&M costs are directly proportional to plant generating output, such as unscheduled maintenance, selective catalytic reduction catalyst and ammonia, oxidation catalyst, water, and other chemicals and consumables. Selective Catalytic Reduction and oxidation catalyst costs were applied to the technologies and locations identified in Section II.C. Variable O&M assumptions for each turbine model and location are summarized in Table II-8.

Table II-8 — Variable O&M Assumptions (2013 \$)*

	All Regions	All Regions	All Regions
	2 x LMS100 PA	1 x 1 x 1 SGT6-PAC5000F(5)	12 Units - 18V50
Major Maintenance Interval (Operating Hours)	50,000	48,000	n/a
Major Maintenance Interval (Factored Starts)	n/a	2,400	n/a
Cost of Parts Required for Complete Major Maintenance Interval:			
- Combustion Turbines (per turbine)	13,500,000	20,200,000	-
- Balance of Plant	-	3,800,000	-
Man-Hours Required for Complete Major Maintenance Interval:			
- Combustion Turbines (per turbine)	14,000	15,000	-
- Balance of Plant			
Unscheduled Maintenance (\$/MWh)	0.86	0.26	0.34
SCR Catalyst and Ammonia (\$/MWh)	1.00	0.15	1.00
CO Oxidation Catalyst (\$/MWh)	0.40	0.05	0.30
Other Chemicals and Consumables	0.18	0.18	0.18
Water (\$/MWh)	0.08	0.09	0.08
	All Regions	All Regions	All Regions
	2 x LMS100 PA	1 x 1 x 1 SGT6-PAC5000F(5)	12 Units - 18V50
Major Maintenance Interval (Operating Hours)	50,000	48,000	n/a
Major Maintenance Interval (Factored Starts)	n/a	2,400	n/a
Cost of Parts Required for Complete Major Maintenance Interval:			
- Combustion Turbines (per turbine)	13,500,000	20,200,000	-
- Balance of Plant	-	3,800,000	-
Man-Hours Required for Complete Major Maintenance Interval:			
- Combustion Turbines (per turbine)	14,000	15,000	-
- Balance of Plant			
Unscheduled Maintenance (\$/MWh)	0.86	0.26	0.34
SCR Catalyst and Ammonia (\$/MWh)	1.00	0.15	1.00
CO Oxidation Catalyst (\$/MWh)	0.40	0.05	0.30
Other Chemicals and Consumables	0.18	0.18	0.18
Water (\$/MWh)	0.08	0.09	0.08

* Includes combustion inspections, hot gas path inspections, and major inspection required, on average, for one complete interval.

1. Fuel Costs

The fuel costs for each peaking unit option are derived from the delivered price of fuel in each region, the net plant heat rate, and the plant dispatch. Fuel prices are derived on a statistical basis, using the historical correlation between daily New York gas costs by location and load and electricity price, as presented in Section III. The statistical approach is used to capture the effects of extreme conditions in the electricity markets on daily and seasonal gas prices. This approach

incorporates fuel prices that are consistent with the hours of the year the peaking unit is actually dispatched.

The fuel price forecasts in Section III account for the transportation cost differences by location. These prices are tied to commodity pricing at delivery points in New York from a major interstate pipeline system that transports natural gas from producing regions along the U.S. Gulf Coast. Local fuel transportation charges were added to the price at the nearest trading point. The applicable local transportation rates include the rate set forth in the following gas distribution company tariff leaves: Con Edison PSC No. 9-Gas (Leaf 277) for New York City, Keyspan PSC No. 1-Gas, Service Classification No. 14 (Leaf 189) for Long Island, Central Hudson Gas & Electric PSC No. 12 – Gas, Service Classification No. 14 (Leaf 196) for Lower Hudson Valley, and Niagara Mohawk PSC No. 219 – Gas, Service Classification No. 14 (Leaf 217) for Albany and Syracuse. In those regions, the total delivered fuel price to an end user for interruptible service is the sum of the following:

- Transco Z6, for NYC, [Transco Z6](#) and [Iroquois Zone 2 for](#) LI, Tennessee Zone 6 for the Capital Region, ~~[Iroquois Zone 2 for the Lower Hudson Valley, or](#)~~ Texas Eastern Transmission Market Area 3 (TET-M3) [and Iroquois Zone 2 for the Lower Hudson Valley, or TET-M3](#) for ROS
- System Cost Component
- Marginal Cost Component
- Value Added Charge
- Taxes
- Imbalance Charges

The System Cost Component, Marginal Cost Component, Value Added Charge, and Taxes are all subject to a minimum monthly bill that is based upon a 55% capacity factor for Long Island and a 50% capacity factor for New York City and the Rest of State. If Imbalance Charges are incurred in the current Rest of State, however, there would be no minimum bill. Conversely, if a minimum bill

(at least 50% capacity factor) is incurred in the Rest of State, then Imbalance Charges would not apply.

According to discussions with representatives from Con Edison and National Grid (with respect to its Keyspan New York City tariffs), the Imbalance Charges are minimal in the day-ahead market. Imbalance Charges for the real-time market would be proportional to the degree of imbalances above a 10% threshold. The imbalances are measured by the difference between the customer's nomination schedule for the next day's deliveries and the actual quantity of gas transported. Those same representatives indicated that firm transportation service is not commonly provided because of the prohibitive costs of system reinforcement. Interruptible gas service gives Con Edison and National Grid (in NYC) the right to curtail gas supply up to 720 hours per year. The risk of gas supply interruption is greatest in the winter months when electric system reliability is less of an issue.

Local fuel transportation charges for each study region are summarized in Table II-9. The tariffs for NYC and Long Island are unchanged from the 2010 Demand Curve Reset Study.

Table II-9 — Fuel Transportation Charges (2013 \$)

	NYC	Long Island	ROS
Gas Transportation Service (\$/mmBtu) *			
— System Cost Component	0.100	0.100	0.100
— Marginal Cost Component	0.092	0.140	0.170
— Value Added Charge	0.005	0.005	—
— Taxes	0.007	0.008	—

	NYC	Long Island	Hudson Valley (Dutchess)	Hudson Valley (Rockland) **	ROS
Gas Transportation Service (\$/mmBtu) *					
System Cost Component	0.100	0.100	0.100	0.100	0.100
Marginal Cost Component	0.092	0.140	0.170	0.170	0.170
Value Added Charge	0.005	0.005	-	-	-
Taxes	0.007	0.008	-	-	-

* The minimum bill must be based on a capacity factor of 55% in Long Island and 50% in NYC, [Hudson Valley](#), and ROS. For a peaking unit, the effective \$/mmBtu cost is thus higher than the indicated rates.

** [Marginal cost component for Orange & Rockland Utilities, Service Classification No. 14, would be \\$0.050/mmBtu if the facility were located adjacent to the company's gas distribution mains.](#)

The net plant heat rates and startup fuel consumption rates for each peaking unit option are summarized in Appendix 1, Table A-2.

The modeling of the peaking unit dispatch in connection with the derivation of energy and ancillary service revenues, and the associated fuel consumption and costs, are discussed in Section III.

I. Development of Real Levelized Carrying Charges

Capital investment costs are converted to annual capacity charges using annual carrying charge rates. The annual carrying charge rate multiplied by the original capital investment yields the annual carrying charges. Carrying charges typically include all annual costs that are a direct function of the capital investment amount: principal and interest payments on project debt, equity returns, income taxes, property taxes, and insurance. The assumptions used for property taxes were discussed above. Income tax and financing assumptions are presented in the following subsections.

1. Income Tax Assumptions

Income taxes are a significant component of carrying charge rates. A portion of these charges must be grossed up to account for the income taxes due on plant revenues such that the desired return on equity is achieved. Income taxes include the federal corporate tax rate of 35.00%, the New York State corporate tax rate of 7.10%, and the New York City income tax rate of 8.85%. The composite tax rate is the sum of these rates, reduced by the portion that is deductible from taxable income. Income tax assumptions for each region are summarized in Table II-10.

Table II-10 — Income Tax Assumptions

	NYC	Long Island and ROS
Federal Tax Rate	35.00%	35.00%
State Tax Rate	7.10%	7.10%
City Tax Rate	8.85%	0.00%
Composite Tax Rate *	45.37%	39.62%

	NYC	Long Island	Lower Hudson	ROS
Federal Tax Rate	35.00%	35.00%	35.00%	35.00%
State Tax Rate	7.10%	7.10%	7.10%	7.10%
City Tax Rate	8.85%	0.00%	0.00%	0.00%
Composite Tax Rate *	45.37%	39.62%	39.62%	39.62%

* Federal tax rate + State tax rate + City tax rate – [Federal tax rate x (State tax rate + City tax rate)], to account for the deductibility of state and local taxes from federal taxable income.

2. Financing Assumptions

Financing assumptions for each region are discussed in Section IV.B and summarized in Table **Error! Reference source not found.II-11**. The values are identical for each region except for the after-tax weighted average cost of capital, which is lower in New York City because of the city income tax. The costs of debt and equity are shown on a nominal basis and a real basis. Real rates are derived by removing the inflation component of 2.30%, and are subsequently used to calculate the real weighted average cost of capital (WACC) and the real levelized carrying charge rates.

Table II-11 — Financing Assumptions

	NYC	Long Island and ROS
Equity Fraction	0.50	0.50
Debt Fraction	0.50	0.50
Cost of Equity (nominal)	12.00%	12.00%
Cost of Debt (nominal)	6.50%	6.50%
Cost of Equity (real)	9.48%	9.48%
Cost of Debt (real)	4.11%	4.11%
Weighted Average Cost of Capital *		
Before-Tax (nominal)	9.25%	9.25%
After-Tax (nominal)	7.78%	7.96%
Before-Tax (real)	6.79%	6.79%
After-Tax (real)	5.86%	5.98%
Amortization Period (years)	25 years (debt); 30 years (equity)	25 years (debt); 30 years (equity)
Tax Depreciation **	15-year MACRS (simple cycle); 20- year MACRS (other)	15-year MACRS (simple cycle); 20- year MACRS (other)
Inflation Rate	2.30%	2.30%

	NYC	Long Island	Lower Hudson Valley	ROS
Equity Fraction	0.50	0.50	0.50	0.50
Debt Fraction	0.50	0.50	0.50	0.50
Cost of Equity (nominal)	12.00%	12.00%	12.00%	12.00%
Cost of Debt (nominal)	6.50%	6.50%	6.50%	6.50%
Cost of Equity (real)	9.48%	9.48%	9.48%	9.48%
Cost of Debt (real)	4.11%	4.11%	4.11%	4.11%
Weighted Average Cost of Capital *				
Before-Tax (nominal)	9.25%	9.25%	9.25%	9.25%
After-Tax (nominal)	7.78%	7.96%	7.96%	7.96%
Before-Tax (real)	6.79%	6.79%	6.79%	6.79%
After-Tax (real)	5.86%	5.98%	5.98%	5.98%
Amortization Period (years)	30 years	30 years	30 years	30 years
Tax Depreciation **	15-year MACRS (simple cycle); 20-year MACRS (other)	15-year MACRS (simple cycle); 20-year MACRS (other)	15-year MACRS (simple cycle); 20-year MACRS (other)	15-year MACRS (simple cycle); 20-year MACRS (other)
Inflation Rate	2.30%	2.30%	2.30%	2.30%

* $(\text{Equity Fraction} \times \text{Cost of Equity}) + (\text{Debt Fraction} \times \text{Cost of Debt})$, before tax; and $(\text{Equity Fraction} \times \text{Cost of Equity}) + [(\text{Debt Fraction} \times \text{Cost of Debt}) \times (1 - \text{Composite Tax Rate})]$, after tax.

** Federal tax code schedule (Modified Accelerated Cost Recovery System or MACRS) adjusted for residual depreciation if the amortization period is less than the number of years indicated.

Consistent with the 2010 Demand Curve Reset Study, this study uses a methodology that determines a separate amortization period for each region. The difference by region considers the risk of excess capacity, the slope of the Demand Curve, and the slope of the energy and ancillary service net revenue function. This method from the prior Demand Curve reset ties together the risk and the slope of the Demand Curve and provides for an internally consistent consideration of the Demand Curve slope, which affects risk, and the amortization period.

3. Levelized Cost Results

For each case, the annual carrying charges were calculated over the amortization period. Annual carrying charges are equal to the sum of the following components:

- **Principal.** Based upon mortgage style amortization.
- **Interest.** Equal to the cost of debt multiplied by the loan balance for the given year.
- **Target Cash Flow to Equity.** Equal to the initial equity investment multiplied by an annuity factor over the amortization period, using the cost of equity as the annuity rate.
- **Income Taxes.** Calculated by the formula: $[t/(1-t)] \times [\text{Target Cash Flow to Equity} + \text{Principal} - \text{Annual Tax Depreciation}]$, where t = Composite Tax Rate. Annual tax depreciation is based on the MACRS depreciation schedule in accordance with the federal tax code for the applicable technology.
- **Property Taxes.** The effective property tax rate multiplied by the original capital investment amount, escalating each year with inflation.
- **Insurance.** The insurance rate multiplied by the original capital investment amount, escalating each year with inflation.

Annual carrying charge rates on a hypothetical \$1,000,000 capital investment are derived in Appendix 2, Table B-1. Carrying charges derived on this basis result in the specified target cash flow to equity, as verified by the income statement shown in Table **Error! Reference source not found.** II-12.

Table II-12 — Income Statement

	Carrying Charges
minus	Tax Depreciation
minus	Interest
=	Taxable Income
minus	Taxes
minus	Principal
Add back	Depreciation
=	Target Cash Flow to Equity

The levelized carrying charge is equal to the annual carrying charges over the amortization period converted to an annuity using the after-tax WACC. In other words, the annual carrying charges are considered to be “revenue requirements” that are discounted at the after-tax WACC. The real levelized carrying charges are expressed in reference year price levels. Nominal carrying charge rates for future years are equal to the reference year real rate escalated by the inflation rate of 2.30%/year.

The real levelized carrying charge rates as a function of amortization period are summarized in Table II-13. The rates are shown without property taxes and insurance. For reference, the rates in NYC with property taxes and with tax abatement under the Real Property Tax Law are shown.

Table II-13 — Real Levelized Carrying Charge Rates

Based on 15-Year MACRS (IC Engine and Simple Cycle CT)			
	LI and ROS without Insurance and Property Taxes	NYC without Insurance and Property Taxes	NYC without Insurance and with Property Taxes and A07511 Tax Exemption Policy
10-year amortization	10.32	10.81	12.19
15-year amortization	9.96	10.40	11.79
20-year amortization	9.65	10.05	11.43
25-year amortization	9.37	9.73	11.12
30-year amortization	9.14	9.46	10.84
35-year amortization	8.70	8.97	10.35

Based on 20-Year MACRS (Combined Cycle)			
	LI and ROS without Insurance and Property Taxes	NYC without Insurance and Property Taxes	NYC without Insurance and with Property Taxes and A07511 Tax Exemption Policy
10-year amortization	10.64	11.21	12.60
15-year amortization	10.28	10.81	12.19
20-year amortization	9.97	10.45	11.83
25-year amortization	9.70	10.14	11.52
30-year amortization	9.46	9.87	11.25
35-year amortization	9.03	9.37	10.75

Based on 15-Year MACRS (IC Engine and Simple Cycle CT)			
	LI and ROS without Insurance and Property Taxes	NYC without Insurance and Property Taxes	NYC without Insurance and with Property Taxes and A07511 Tax Exemption Policy
10-year amortization	16.48	17.09	17.09
15-year amortization	12.76	13.26	13.26
20-year amortization	10.87	11.28	12.00
25-year amortization	9.80	10.16	11.29
30-year amortization	9.14	9.46	10.84
35-year amortization	8.70	9.00	10.55

Based on 20-Year MACRS (Combined Cycle)			
	LI and ROS without Insurance and Property Taxes	NYC without Insurance and Property Taxes	NYC without Insurance and with Property Taxes and A07511 Tax Exemption Policy
10-year amortization	16.72	17.39	17.39
15-year amortization	13.11	13.69	13.69
20-year amortization	11.26	11.76	12.48
25-year amortization	10.15	10.60	11.72
30-year amortization	9.46	9.87	11.25
35-year amortization	9.00	9.38	10.93

In addition to the effects of region and property taxes and insurance, the sensitivity of the carrying charge rates over a range of amortization periods (10 to 35 years) and for higher costs of debt and equity (base case, base case + 200 basis points, and base case + 400 basis points) are shown in Appendix 2, Table B-2.

IV.III. Estimating Energy Net Operating Revenues

The next task is to estimate the annual net operating revenues of the reference peaking facility. The net operating revenues are required by the Services Tariff to be based on conditions in which the available capacity is equal to the minimum installed capacity requirement (*i.e.*, the NYCA Minimum Installed Capacity Requirement, the Locational Minimum Installed Capacity Requirement (LCR) for Localities J and K, and the Indicative NCZ Locational Minimum Installed Capacity Requirement (Indicative NCZ LCR) for NCZ G-J) plus the capacity of the reference peaking plant.⁴⁵

A. Approach

We used historical data for zonal day-ahead and real-time LBMP values from November 1, 2009 through October 31, 2012 to benchmark the operation of the NYISO system. We then statistically estimated the effect of various cost drivers on the observed zonal LBMP values. This statistical model allows us to conceptually vary any identified causal variable – one that affects LBMPs either directly or indirectly – to create an estimate of price under differing conditions, with respect to that variable. ~~A causal variable is a variable that affects LBMPs.~~ The primary causal variables we identified were load, temperature, daily natural gas prices and the addition of two major plants in New York City during the historical period. The statistical model was employed to develop hourly forecasts of real-time and day-ahead LBMPs for each NYISO zone that reflected forecast load levels for the period from May 2014 to April 2017. Those forecasts do not reflect conditions in which the available capacity is equal to the minimum installed capacity requirement plus the capacity of the reference peaking plant, nor the expected resource mix, but by necessity reflect capacity actually available in the historical period, adjusted to reflect the two new major plant additions in New York City as operating for the entire historical period.

In order to adjust these forecasts to reflect the expected resource mix, as well as conditions in which the available capacity is equal to the minimum installed capacity requirement plus the capacity of the reference peaking plant we arranged for GE Energy Consulting (GE Energy) to

⁴⁵ Services Tariff §5.14.1.2.

conduct production costs simulations of the NYISO dispatch in the May 2014 to April 2017 period. GE Energy conducted these simulations using their Multi-Area Production System (MAPS). MAPS is a detailed production costs simulation system that models the NYISO and interconnected ISOs accounting for the impact of the transmission configuration on dispatch. MAPS produces, among other outputs, zonal LBMPs by hour. We compared the LBMPs from various cases and developed a detailed set of ratios that measured the relationship between the MAPS simulated LBMPs in various cases and used these ratios to adjust LBMPs developed from the statistical model. One of the MAPS cases corresponded to conditions in which the available capacity is equal to the minimum installed capacity requirement plus the capacity of the reference peaking plant.⁴⁶ We then adjusted the LBMPs forecast by the statistical model at conditions which reflected actual available capacity in the historic period by the ratios between the zonal LBMPs developed from these two MAPS simulations. These adjustments yield LBMPs developed using the statistical model that reflect the expected resource mix, and conditions in which the available capacity is equal to the minimum installed capacity requirement plus the capacity of the reference peaking plant.

The table below shows how various major resources are represented in the statistical analysis and the GE MAPS modeling. As discussed below, the GE MAPS modeling utilized the NYISO's 2011 "CARIS 2" data base.

Resource	CARIS 2 As Found	Statistical Analysis	CARIS 2 Matching Statistical Analysis	CARIS 2 Target Case
Athens SPS	Out	In	In	In
HTP	In	Out	Out	In
Danskammer	In	In	In	Out

⁴⁶ This was implemented to reflect an excess level equal to 190 MW above the minimum required installed capacity level for NYCA and each locality. Hence, the excess level is greater the lower the LCR for any locality. In order to populate the Demand Curve model used by NERA, GE Energy also provided NERA a series of MAPS runs in which the excess levels of each locality were increased or decreased in 2% increments through change to load levels.

Resource	CARIS 2 As Found	Statistical Analysis	CARIS 2 Matching Statistical Analysis	CARIS 2 Target Case
Dunkirk 3 & 4	Out	In	In	Out
Astoria 2	Out	In	In	Out
Astoria 4	Out	In	In	Out
Far Rockaway 4	Out	In	In	Out
Glenwood 4	Out	In	In	Out
Glenwood 5	Out	In	In	Out
Nine Mile 2 Update	In	Out	Out	In
Astoria Energy 2	In	In	In	In
Bayonne Energy Center	In	In	In	In

Below is information about each case that will help in reviewing the above table.

- The CARIS 2 As Found case is the basic data set provided by NYISO. It is intended to be a realistic representation of the future. Two items in this data base, however, changed since it was developed. First, an agreement was reached to continue operation of the Athens SPS. Second, the retirement of Danskammer was announced and to our understanding will not lead to any reliability problems that would require continued operation of the plant. The resulting case reflects the system with the expected resource mix.
- The statistical analysis reflects history. With respect to Astoria Energy 2 and Bayonne Energy Center, the plants operated for part of the historical period, but are considered in for the entire analysis as they were modelled as operating through the use of dummy variables. For all other resources except the Athens SPS, HTP and Danskammer, the In

or Out designation reflects the status of the plants for most all of the period. The Athens SPS, Danskammer, and HTP designations apply to the entire period.

- The CARIS 2 Matching Statistical Analysis Case was developed to represent the relative MAPS LBMP results of the statistical analysis. It contains the historical resource mix comparable to that reflected in the statistical analysis.
- The CARIS 2 target case, on which the net energy revenues for this reset are to be based, was developed utilizing a resource mix reflecting the expected resource mix with load levels adjusted so that excess levels were equal to the capacity of the reference peaking plant. Various capacity level cases were developed from this case by adjusting peak and energy load levels.

Having predicted the LBMPs corresponding to the tariff excess level requirement, we must next create a hypothetical operating strategy for this specified plant. To accomplish this, we must decide upon what degree of foresight we assume the plant operator will have; in choosing between commitments to the ~~day-ahead~~[Day-Ahead](#) Market versus opportunistic behavior in the ~~real-time~~[Real-Time](#) Market. In addition, we must be mindful of real operating constraints on the plant with regard to start-up cost and start times. The dispatch and operation analysis is performed by zone considering LBMPs and gas prices applicable to each zone. In general, we assume that the plant will make cost based offers in the day-ahead market and will be selected to operate in that market when economic considering all costs including start-up costs.

Furthermore, we assume that if the plant is scheduled to operate in the day-ahead market if it is economic and is permitted by its start time, it can start-up and operate in response to prices in the real-time market. When examining combined cycle units, for informational purposes, we also allow them to operate at minimum load during periods of loss between starts, to avoid incurring additional start-up costs and so long as those losses do not exceed the plant's start-up costs. We evaluate the plant's operating cost on a daily basis, using day-ahead natural gas prices applicable to the location of the plant and from two days prior to the actual day. We also use variable O&M costs provided by S&L and emissions costs based on market prices for emission allowances for this evaluation. The end result is a forecast of the net energy revenues that the hypothetical plant

could earn over the reset period, at conditions in which the available capacity is equal to the minimum installed capacity requirement plus the capacity of the reference plant.

In the two previous Demand Curve reset analyses we used only a statistical model. The model specification included the level of capacity (reserve margin) as a causal variable. The forecast prices were an adjustment to the capacity level specified in the Services Tariff through use of the reserve margin coefficient. For this reset, we augmented the methodology so that an adjustment to the capacity level specified by the tariff is made based upon information developed using a production cost model – MAPS. We proposed this methodology to address the fact that the historical period would contain very few, if any, observations under conditions in which the available capacity was equal to the minimum installed capacity requirement plus the capacity of the reference peaking plant. Adjusting to that capacity level using the statistical model would involve extrapolation, which, for the reasons which we will present, is undesirable.

Extrapolation is a methodology to forecast outside the range of observed data upon which a model is based. Extrapolation implicitly assumes that the relationship between the causal variable(s) and the predicted variable(s), outside the range of the observed data, remains the same as within that range. To avoid the need to make this potentially inaccurate assumption, we instead combined the statistical approach and production cost modelling, such that the primary forecasts were developed using the statistical approach and then adjusted to conditions developed from production costs model analyses. In addition to avoiding extrapolation, this approach has another positive attribute: the combined approach allows for a capacity level adjustment that can also account for changes in the resource mix composition. In particular, using MAPS to adjust the statistical results to the conditions as described, we also can specifically adjust for events such as the addition of the HTP intertie between PJM and New York City; the retirement of the Danskammer, Far Rockaway and the Glenwood Landing plants; and the mothballing of the Dunkirk plants, Astoria 2, and Astoria 4, in a way that considers not just the capacity of the resource, but also how the resource affects dispatch. Given the high volume of resource changes that have occurred in the NYISO system during the current reset period, this capability is desirable.

In conducting the MAPS analyses, GE Energy used the MAPS data base developed by NYISO for the 2011 Congestion Assessment and Resource Integration Study (CARIS). CARIS is the

economic planning process used by NYISO to evaluate the benefits of proposed economic transmission projects developed and submitted to the NYISO to relieve transmission congestion. The “2” designation indicates that the data base was from the second and final round of the CARIS process and was updated from the 2011 CARIS 1 data base in the latter half of 2012. Hence the data base was recent, had been through review and validation by NYISO and stakeholders, and was being used to consider transmission investments. This data base had already accounted for many of the resource changes described above. The only changes made to the data base were to change the resource mix to reflect the retirement of Danskammer and the continued operation of the Athens SPS, neither of which was reflected in CARIS 2. GE Energy also conducted a “baseline” MAPS simulation that reflected the historical resources consistent with NERA’s statistical analyses. Finally, MAPS simulations were conducted with adjusted peak and energy so that these values on a locational basis reflected conditions in which the available capacity is equal to the minimum installed capacity requirement plus the capacity of the reference peaking plant.⁴⁷ As the CARIS 2 data base had recently been reviewed and validated by NYISO and stakeholders, they were taken as found and we did not repeat the review and validation process.

In our approach we only use the LBMPs from MAPS to adjust the projected LBMPs developed from the statistical model. We do this for several reasons. First, while MAPS and the CARIS 2 data base have been validated by NYISO as reasonable for planning purposes, it can be very difficult to implement any model which is a detailed simulation of electric system operation in a way that will precisely forecast absolute prices. Literally thousands of inputs are required and it is impossible to reflect isolated actual events that may impact price. A simulation model is well suited to viewing the magnitude of significant load or resource change on price and likely can produce good estimates of price but cannot be expected to produce absolute prices that will necessarily match actual experience. The statistical approach on the other hand begins with the actual distribution of prices for each zone. These prices are changed in response to changes in

⁴⁷ This was implemented to reflect an excess level equal to 190 MW above the minimum required installed capacity level for NYCA and each locality. Hence, the excess level is greater the lower the minimum required installed capacity level for any locality. In order to populate the Demand Curve model used by NERA, GE energy also provided NERA a series of MAPS runs in which the excess levels of each locality were increased or decreased in 2% increments through change to load levels.

the ~~casual~~causal variables. We also further adjust our predictions to amount for the errors observed in developing the regression equation and we apply these errors to the predictions of the statistical model. While the statistical analysis is only as accurate as the coefficient related to the ~~casual~~causal variables, the validity of these coefficients and the explanatory power of the generation can be measured. When the errors are retained and applied to the new predictor, the forecast is, in our opinion, as accurate a forecast as can be reasonably be developed for a three year forward period as it affects many unique and idiosyncratic events that could not possibly be simulated using a model. While these exact events will not concur in the forecast period, we believe it is reasonable to assume that events with similar impacts will occur.

Second, the statistical approach incorporates hourly detail for both real-time and day-ahead LBMPs. Additionally, the statistical model uses the day-ahead, location-specific gas prices that are consistent with the hourly real-time and day-ahead electricity prices. MAPS, on the other hand, does not model daily gas prices and does not produce distinct day-ahead and real-time prices.

Third, a simulation model such as MAPS is primarily designed to provide very useful information on the relative impact of system changes such as changes in transmission configuration, resource mix and changes in the ratio between the installed capacity and load level. By contrast, a statistical approach is limited in these capabilities. By combining the two approaches we draw upon the strengths of each and given the significant changes to the supply resource anticipated over this reset period this combination approach can be expected to be more accurate than either approach alone.

We note that there is no method to generate a forecast that can be guaranteed to be perfectly accurate. Because the net revenue calculation is hypothetical, we strive to model the important parts of the problem, but recognize that there are numerous small effects which are not modeled and which, by the law of large numbers, should roughly cancel one another out. Excessive focus on particular small issues raises the possibility of an unbalanced look at the problem in which the noise generated by the estimation process exceeds the effect of the primary drivers in the estimate. Consequently, the generation of net revenue estimates, while scientific, nonetheless calls for the exercise of professional judgment, as does almost any hypothetical modelling. We

will discuss later in this section of the report various factors which we attempt to capture and those factors which we do not believe it is feasible or desirable to attempt to capture.

B. Data

The hourly day-ahead and real-time hourly integrated zonal LBMPs are publicly available at the NYISO website, as are zonal loads. These prices were augmented by daily gas prices from two days before the day examined taken from Bloomberg (Texas Eastern Transmission M3 price for Zones A-E, Tennessee Zone 6 for Zone F, Iroquois Zone 2 for Zones G-I and Transco Z6 prices for NYC and Long Island) which were then linearly interpolated across non-trading days. The use of two day prior gas prices was a better fit than one day prior gas prices and we used these previously. For [plants in](#) New York City, the Transco Z6 prices were increased by 6.9 percent to reflect fuel taxes. Temperatures were from data supplied by National Oceanic and Atmospheric Administration. Temperatures for Long Island and New York were taken at JFK airport, temperatures for Load Zones F and G were taken at Albany airport and temperatures for Zone C were taken at Syracuse Airport.

C. Statistical Estimation

The fitting of a statistical equation to predict electricity prices is a reasonably straightforward exercise. Electricity price in any hour in any zone is determined by the intersection of offers to supply power and the estimated (if day-ahead) or actual (if real-time) demand for power, adjusted for limitations, if any, of the transmission system to minimize total resource costs. The supply curve of electricity is largely fixed, but moves somewhat from hour-to-hour as transmission conditions change, the availability of plants change, and because of other transient factors, *e.g.*, temperature. If, as a first approximation, we regard the supply curve is fixed, then varying demand traces out the supply curve. Thus, our estimation strategy is to use load to identify the supply curve while varying the supply curve from hour-to-hour to reflect underlying technical supply differentials. The remainder of unmeasured effects, which are substantial, are left as residuals in the underlying model. Thus,

$$\text{Log}(\text{LBMP}_{hz}) = f(\text{NYCA Load, Zonal Load, Attributes of Hour } h, \text{ Attributes of Zone } z, \text{ Gas Price, Other Known Supply Shifters, Temperature}) + \varepsilon$$

We choose to use the logarithm of LBMP rather than raw LBMP for several reasons:

- Prices are normally thought of as behaving multiplicatively – external drivers on price are, for the most part, expected to affect those prices in percentage terms rather than absolute terms, and a logarithmic specification reflects this.
- Logarithmic specifications reduce inherent issues in heteroskedasticity in the observed data, in which large errors are far more likely at high prices than at low prices.
- Logarithmic models prevent prices from being estimated as below zero. While the LBMP can in theory fall below zero, it did not in the reference period and is unlikely to do so ever, given the structure of the NYISO market. Even very good regressions in levels have the undesirable (though not for our purposes, fatal) objection that they occasionally predict substantial negative prices. This effect is particularly prevalent when the regression has underpredicted price and the observed absolute residual is applied to a hypothetical variation around that price.

The complete specification is given in Appendix 3. The standard indicia of model fit are quite good. The basic regression model explains about 87 percent of the underlying variation in electric prices⁴⁸. This result implies that given the zone, the hour, the NYCA and zonal load, Gas Price, and temperature, we can capture about 87 percent of the variation in electricity price around its mean. The remaining 13 percent of the variation that is unexplained is implicitly accounted for by a combination of variables excluded from the estimation process; these might include levels of outages, transient system conditions, among other qualitative and quantitative factors.

Almost all causal factors, except temperature work as expected. Thus, for example, price increases as load increases, and increases faster the more load increases.⁴⁹ Prices are generally higher on the weekends and in the shoulder months (adjusting for load differences) to reflect

⁴⁸ The equivalent figure for the similarly structured 2007 and 2010 models respectively, were 83 and 88 percent. Removing the reserve margin variable from the equation has thus not diminished the explanatory power of the equation.

⁴⁹ This result follows from the strongly positive effects on the cube of load.

outage patterns on deferrable maintenance. Temperature has a slightly anomalous effect, in that one would expect high temperatures to lead to higher prices. Instead, there is a moderately small effect in which higher minimum temperatures lead to lower prices, while the maximum temperature effect is small and insignificant.

In their report on the New York capacity market, FTI Consulting (FTI) presented two critiques of the statistical future price estimation process that we used in the prior reset and use again in this reset. First, they suggest that the use of a logarithmic prediction method “could” mask the predictive accuracy of the ultimately important thing being forecast, namely prices. Second, they suggest that the assessment of the model needs to be based on “how well the model predicts prices in high priced hours.”⁵⁰

We agree in general with these observations, but believe the methodology should be based on a logarithmic specification as it is more accurate, and it does predict prices in high priced hours as we retain and reapply the residuals.

First, FTI’s observation that when a logarithmic model accurately predicts some underlying variable, the percentage of variation explained in the underlying level variable will always be lower is true but not germane to which model specification should be utilized. If the underlying relationship is better explained by a logarithmic relationship, which it is, it is that logarithmic relationship that should be used in estimation. There are roughly linear effects in price percentages, not in prices themselves. When we then transform the predictions back to prices, the percentage of variance explained will be lower, because the correlation is no longer linear, but that does not mean that directly using a statistical model to predict prices would be more accurate. FTI seems to be implying that if what you want to know is Y, your forecast method must forecast Y. But if Y is not linearly related to the predictors, this view is not correct. What is appropriate to do is to use an accurate linear method to predict, and then make sure that the error structure is preserved on transformation back to Y. This is exactly what we have done. In our modelling, we save the underlying residuals (the errors) of the model and reapply them in

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http://www.nyiso.com/public/webdocs/markets_operations/documents/Studies_and_Reports/Studies/Market_Studies/Final_New_York_Capacity_Report_3-13-2013.pdf -- pages 54 to 59

every prediction. Thus, the underlying error structure, whatever it is, is precisely preserved when going from the log model to the level model. This nullifies the objection that our model does not preserve or somehow artificially narrows a realistic distribution of price and price movements that occur randomly and infrequently.

We are happy to report the percentage variations in underlying prices instead of the log percentages, but caution that the two estimates are not commensurate and that therefore the percentage of variation explained is not comparable between the two models. As it happens, the difference between the two is not very large: while the log model explains 87 percent of underlying logarithmic variation, the transformed predictions explain 80 percent. Note that these two figures are not directly comparable, and that there is no absolute standard of predictability.

As to whether or not the model is in general accurate as to the size of causal effects, or as to whether or not it predicts accurately at particular times, we have carried out extensive experimentation to try and fulfil exactly these criteria. But stakeholders do not need to rely on our say-so. As in past resets we have turned over to stakeholders both the raw data used to generate the results, the computer programs used to generate the estimates, and the estimated model and stakeholders can experiment with alternate model specifications.

D. Specific Items Reflected in Implementing the Approach

While we have described the approach above, we believe it is useful to provide a more detailed discussion of specific items reflected in the application of the approach. This section discusses these items.

1. Resource Mix

The biggest change in the New York resource mix over the last three years was the additions of Astoria Energy 2 ([AE 2](#)) and the Bayonne Energy Center, ([BEC](#)), which have been fully adjusted for in the econometric model. There are a number of other changes that either occurred too late in the historic period to have had a meaningful effect on energy prices (*e.g.* the retirement or mothballing of steam plants in Queens and Long Island and the uprate on Nine Mile 2) or did not take place until the beginning of the forecast period, *e.g.*, the Hudson Transmission Partners 660 MW line connecting NYC to PJM. [Comments on the initial draft were offered that suggested](#)

that resource mix changes related to the addition of AE 2 and BEC were not appropriate and that the impact of these resources would be sufficiently captured by accounting for their effect on prices in the next reset period. We understand the comment, and agree that many random factors are best accounted for by letting their impact be reflected in prices over time as such impacts become observable. However, these additions, combined with HTP, provide over 1600 MW of new and potentially lower energy cost capacity directly to NYC. As the average load in NYC is under 7500 mw per hour, these additions can potentially supply 20% of average load in NYC which has the potential to have a very significant impact on LBMPs. As an adjustment for these additions is possible and can be based on data observed for a decent part of the historic period is possible, we recommend accounting for this change in the resource mix. For the AE2 unit, the fact that the regression period fairly neatly divides into an early period without it and a later period which includes it creates an almost ideal structure for estimating the effect. . While it is true that variables other than AE2 also change across the periods with and without AE2, we have examined the correlations between the periods and other variables such as gas prices and are comfortable that they should not be distorting the AE2 impact. Of the main price drivers, only gas prices are greatly different in the pre- and post-AE2 period. Different specifications in which the AE2 period was interacted with gas prices gave essentially unchanged estimates of gas price elasticity over the two periods, however. Thus, the lower prices observed in the later period are a combined effect of lower gas prices and the existence of AE2, but the constancy of the gas price effect undermines the notion that the AE2 indicator variable is confounding gas price changes. In the post-Bayonne period, while gas prices are low, gas prices are also quite stable, exhibiting much lower volatilities. Consequently, the drop in prices post-BEC entry cannot simply be attributed to lower gas prices, as these prices were not much lower than they were in the period after the entry of AEC and before the entry of Bayonne.

The plausibility of the BEC effect (except on Long Island) derives from the fact that an addition of a slightly less efficient unit of similar size ought to have a slightly lower effect on observed LBMPs. As an additional check, we calculated a load-equivalency for these effects, i.e., how much lower would load have to be to give effects of similar magnitude over this period. The derived results were only slightly larger than the sizes of the two units and propagated appropriately (with the exception of Long Island post-BEC) back through the system from New

York, with larger absolute effects in NYC, smaller effects in the Lower Hudson Valley and even smaller effects further upstate. This pattern is not matched by the pattern of the change in natural gas prices. The BEC unit prediction is not as robust as AE2, because BEC is only in the last five months of data, we have no winter observations and the summer of 2012 experienced extreme weather. BEC has 61 percent of the effect of AE2 in Zone J, and 58 percent of the effect of AE2 in Zones G-H. Given that the plants are roughly the same size, but BEC has a higher heat rate, the BEC adjustment variable appears to be reasonable, even though it is estimated over a period that does not include any winter months. On the other hand, the BEC effect on Long Island was implausibly positive, and we have ignored this effect in the LBMP future modeling. From a statistical perspective, the BEC value was positive because in July 2012, Long Island LBMPs were \$40 per MWh above NYC LBMPs, a magnitude that is very unusual and dominates any other impacts on Long Island prices measured from a short period that includes this month. In our opinion, adjusting for BEC is more indicative of the conditions over the reset period, even if the adjustment may be imperfect.

As described when discussing the approach, we have been able to make adjustments to the future resource mix of elements not captured in the historic period by relative adjustments from the results of the two GE MAPS run. The first MAPS run will set a baseline approximately equal to the historic period. The second run alters the resource mix to reflect the going-forward expected mix. The ratio of prices in these two runs, averaged over 12 months and 24 hours, create 288 multiplicative factors for the prices from the econometric model.

2. Adjustments for Capacity Excess Level

As described previously, MAPS simulations were conducted with adjusted peak and energy so that these values on a locational basis reflected conditions in which the available capacity is equal to the minimum installed capacity requirement plus the capacity of the reference peaking plant. The ratio of prices between these runs and the runs adjusted for resource mix, also averaged over 12 months and 24 hours, creates 288 factors for adjustment of the prices in the econometric model. Additional MAPS simulations were conducted with uniform positive and negative increments from the capacity levels in each locality in order to specify the relationship between prices and capacity excess in the model. These MAPS LBMP derived adjustment factors are utilized to estimate net energy reserves at various installed capacity levels including

conditions where installed capacity is equal to the minimum installed capacity requirement plus the capacity of the reference peaking plant. In past resets, estimates at various installed capacity levels were developed as an econometric coefficient. As previously explained that is no longer desirable due to the need to extrapolate to estimate those coefficients and the ability of GE MAPS to capture the impact of resource mix changes.

The use of the observed excess levels as a causal variable in the prior reset proved controversial, and not without reason. The data from which that estimation was derived, exhibited variation mostly attributable to seasonal changes, and there was no possible adjustment for the resource composition of the units which entered or exited the supply stack. While we still stand behind the derived estimate as a very reasonable estimation of the excess level impact measures using an econometric approach (approximately a 1.3 percentage change in price per percentage point change in excess), we did concede that the specific point estimate was not necessarily robust to alternative specifications. We further conceded that extrapolation of this value far outside of the observed range of excesses raised a separate set of questions. That said, we note that the alternative MAPS-based methodology to estimate the effect of reserve margin changes gives quite similar results for changes of 2-3 percentage points in margin: 3-5 percent in LBMPs. Larger changes in excess levels do seem to have smaller changes in LBMP than our previous results, but this effect is true for both large excesses and large deficits; thus, the weighted average of results from our Monte Carlo simulations should be similar.

{NTD – the MAPS runs we used begin with a base where each region and NYCA has an excess of 190 MW over the ICR/LCR. This is appropriate as for all regions the peaking plant is roughly 190 MW in ICAP value. Plus and minus sensitivities were intended to vary around this level, but in fact actually varied around the ICR/LCR. The results are not what was fully intended. For example when we look up results for NYC at minus 6%, the excess level in all locations and in NYCA is minus 6%. We had intended that the minus 6% case would be 6% less than the ICR/LCR plus 190 in all regions in the minus 6% case. This case would then have a different value in each region. For example, for LI the minus 6 case would be roughly minus 3% (where 190 MW in LI is a 3% excess to start) and for NYCA the minus 6% case would be a 5.5% deficit in NYCA (where a 190 MW excess is about 0.5 % to start). If the cases are rerun so minus 6% was minus 6% from the 190 MW excess level, we would take the minus 6% case for example.

which is in as minus 6% in all regions now and represent it as a different deficit level in each region. We plan to further examine if a rerun is needed. We are confident that any rerun to modify for this factor would have a very minor impact on results (less than \$ 5 per kW year at the extreme) as energy revenues are strongly influenced by the case at a 190 MW excess in each region and this case is correct. We also note that the energy revenue cases for the peaking plant assume a 190 MW excess while the CC has an ICAP capacity of 300 MW. This would also produce an extremely small impact on results and as the CC cases are informational, the value of the information would not be enhanced by adding runs at a 300 MW excess level.}

3. Zonal to Nodal Adjustments

The statistical model uses zonal-level prices as the dependent variable. Since generators are paid nodal prices at ~~wherever~~whatever node they are located, it was felt that this factor should also be accounted for. We have chosen nodes in each relevant zone and have calculated, by month and hour of day, 288 factors to make zonal-nodal adjustments. While generators often have some level of choice as to the bus in which they will interconnect with the NYISO system, and would in some sense naturally choose the highest-price buses, we have not simply based these adjustments on the highest-priced buses. The reason is twofold: first, the fact that higher-priced buses are available is a sign of some barrier to entry at those nodes (land availability, upgrade costs, etc.) which implies that the *net* impact of those high-priced buses is less than the zonal-nodal ratios derived at that node. Second, the addition of a substantial generating plant at the node will, all things equal, decrease the price at that node. ~~{Note to Draft (NTD) — The selection of the appropriate node for each Zone is a work in progress}~~

In selecting the nodes, we considered coordination with the deliverability study being conducted by NYISO to support the Demand Curve reset, and if that study was not applicable, we considered the location of recent entry. In New York City, the locations being examined included East 179th St. in the Bronx, which the NYISO tied to buses at Astoria; Rainey which the NYISO tied to a Ravenswood bus; and Hudson Avenue, which the NYISO also tied to a specific bus. All of these buses were similar, and we used Rainey as representative, although all would have given the same result. These points are on the 345 KV system and have an average basis just over 2% below the zone. In Zone G the points being examined were tied by the NYISO to the Bowline and Roseton buses. The Bowline bus has a basis of just less than 1% below the

Zone while Roseton is nearer to 2%. As both locations were studied for deliverability, we used the Bowline basis for the nodal adjustment. In Zone F, NYISO is studying Rotterdam for deliverability. A price node was not available for Rotterdam. We used Bethlehem, a relatively recent addition with three years of history and a nearly identical basis to the most recent addition Empire, which did not have a full three years of history. For Zones C and K, we also did not have price data at the points studied for deferability. We used the Sithe Independence node in Zone C and the Holtsville node in Zone K.

4. Gas Prices

In the last two reset analyses, we recommended against adjusting for forecast gas prices over the reset period. Effectively this means that when developing hourly prices from the statistical model, the actual daily gas prices from the historical period are used. There are several positive attributes of this approach. First, actual historical gas prices reflect daily and monthly variability. However, we could use a forecast average gas price and still reflect this historical variability. Were we to use a forecast, we would recommend using current gas future prices on average and reflecting volatility based on actual daily historical prices. A second positive attribute of not adjusting for gas prices is that any forecast will, with virtual certainty, not match actual outcomes, while actual gas prices will exactly match outcomes experienced. This does not mean that a forecast should not be used. There are many applications in which the use of a forecast is preferred even recognizing that any forecast is unlikely to exactly reflect actual experience. In our view the Demand Curve is not one of those applications. The responses to price signals given by the Demand Curve are both short run and long run. On a short run basis, plants may decide whether to mothball or not and Special Case Resources may decide whether to offer capacity for periods as short as a month. On a long run basis, decisions to construct new capacity are made in response to the Demand Curve. These long run decisions may well be more efficient if entities making these decisions know that over the life of the facility the Demand Curves will reflect the actual gas prices that are experienced and not a forecast made every three years based on then current gas futures. Further, these long run decisions are of a larger magnitude than the short run decisions. While the timing with respect to gas prices being actually experienced and being reflected in the Demand Curve will not perfectly align, over the

life of the plant, the gas prices experienced will be reflected in the Demand Curve over time, and deviations from forecast will not influence results.

The specific gas price indices we use have been discussed in the Data portion of this Section of the report. Historical gas prices average around \$4.50/MMBtu over the study period, which is quite close to currently-observed future prices for natural gas over the forecast period. Historic prices ranged as high as \$21.71 and as low as \$1.96. While again, we do not propose to adjust for forecast gas prices, given the fact that the historic and future prices are similar, any adjustments we would make would be relatively small.

In the Sensitivity Analysis section of this report we show how using future gas prices would affect results.

{NTD – Market participants have expressed concern that the statistical approach underestimates the impact of gas prices on electricity prices. We understand this concern and the intuition expressed by market participants that there should be a relatively direct link, but also recognize that changes in gas prices can lead to substitution effects which would lessen the link. We are continuing to look into this.}

{NTD – We intend to change the LI gas price to be an average of Iroquois Zone 2 and Transco Zone 6, but have not implemented that yet. This was suggested in LIPA's comments.}

{NTD – The Zone G to J parameters we use in this draft are not yet fully consistent. We are using Dutchess county construction costs, a Rockland county node to zone basis and Iroquois Zone 2 costs. We intend to update. We will test Rockland costs, Bowline basis and Tetco M3 against Dutchess cost, Roseton basis and Iroquois Zone 2 and select lowest cost.}

5. Maintaining the day-ahead and real-time Relationship

We estimate real-time prices after having produced forecasts of day-ahead prices. We do this for each hour by adding the difference between the observed day-ahead LBMP and the regression produced day-ahead LBMP to the observed real-time LBMP.

6. Scarcity Pricing

Scarcity pricing will be implemented when NYISO calls on Special Case Resources. There are two reasons these calls are made. The first reason is that load is approaching available capacity levels and Special Case Resources are needed to serve load and provide operating reserves. This impact should be reflected in the MAPS analyses, as MAPS uses a price of \$500 per MWh when load approaches capacity. Hence, the adjustment of day-ahead prices based on MAPS analyses from current installed capacity levels to installed capacity levels reflecting the minimum required capacity level plus the capacity of the hypothetical peaking plant should capture this element of scarcity pricing. The second reason to dispatch Special Case Resources is that even though there may be adequate capacity that could have been operated if the need was anticipated, due to an unforeseen operational incident including but not limited to transmission outages, Special Case Resources are required. As our real-time LBMPs already include the impact of scarcity pricing events of this nature, and hours in which real-time prices are well above day-ahead prices, our net revenue estimates, which include a supplement for operation in the real-time market as prices spike (if the plant was not dispatched in the day-ahead market) will capture this impact. As this impact is operational, and should not be related to installed capacity level, there is no need to change this impact on net energy revenue as a function of the installed capacity level. Hence, no additional adjustment is needed to capture scarcity pricing.

7. Miscellaneous Factors

There are variety of factors and developments in the market that cannot practically be modeled with confidence and it may be that making an estimate would introduce more error than not adjusting for the factor. Similarly, if we were to take a subset of these factors that moved results in only one direction and ignore factors that moved results in the other direction, we would not only be possibly introducing error but would also be introducing bias. We discuss here items we are aware of, but have not modeled. The first item is that we use a dispatch that implicitly contains perfect foresight of prices. This could lead to an overstatement of net energy revenues. However, as the plant will be able to bid its start-up costs and will be made whole for losses if dispatched by NYISO, we anticipate that any overstatement would be small and note that we could not practically model this. The second item going in the same direction is that we implicitly assume that all gas can be purchased at the two day-ahead price and do not model the

intra-day gas market or cost of deviating from scheduled gas purchases. This impact is offset to some degree by the fact that we do not consider opportunities for a plant scheduled in the day-ahead market to reduce output and provide its day-ahead commitment from the real-time market if more economic than operating. Going in the other direction we have used RGGI allowance prices from the most recent auction which are reflective of the RGGI floor price and history. Changes to the RGGI program are generally viewed as leading to higher RGGI allowance prices over the reset period. As the hypothetical plant is more efficient than the plants that will be setting LBMPs when the hypothetical plant is dispatched, accounting for increased RGGI prices would be expected to increase LBMP by more than the plant's operating cost and lead to somewhat higher net energy revenue. Additionally market evolutions and improvements are made over time. Two current examples are a change in Ancillary Service markets that should increase Ancillary Service revenues⁵¹ and a change to scarcity pricing rules that should increase the number of dispatch intervals in which scarcity pricing applies. Market evolutions, which are very hard to model, appear to most often work in the direction of increasing revenue opportunities for generators. Hence, not accounting for market evolutions will also mitigate the impact of not accounting for factors which work to possible overstate net energy revenues. On balance when we consider the impracticality of adjusting our forecast of net energy revenues for these factors and the fact that such factors have offsetting impacts we recommend not adjusting the forecast for any of these factors.

8. Ancillary Service Revenues

~~Finally, we have included adjustments for Ancillary Services revenues for operating reserves, voltage support service, and regulation. The NYISO supplied us with average Ancillary Service revenues over the last several years for similar units, and we have added these values in.~~
~~{NTD—update will be made when data is analyzed.}~~

Finally, for the LMS 100, we have included adjustments for Ancillary Services revenues for operating reserves and voltage support service (VSS). The NYISO supplied us with average

⁵¹ NERA has discussed the AS market changes with the MMU and has been advised that the proposed change to the AS market would be unlikely to have a significant impact on the 10 minute non spinning revenues that could be earned by the LMS 100.

Ancillary Service revenues for units capable of providing 10 minute non spinning reserves. The Ancillary Service revenues earned by these units would be similar in type to those that could be earned by the LMS 100. The analysis showed that these units (in the East – Zones F to K) earned on average \$11.11 in 10 minute non spinning reserves per KW of ICAP capacity and \$0.97 per KW of ICAP capacity for VSS. However, these units were considerably older and less efficient than the LMS 100 and would be expected to earn more in non spinning reserve revenues since they would operate less. Thus, the value of \$ 11.11 was multiplied by a factor that was the sum of the 10 minute non spinning price over the hours that the unit did not operate in the simulated dispatch divided by the sum of the 10 minute non spinning price over all hours. The factor was calculated over the three year historical period used in the regression. This ensured that non spin reserve revenues could only be earned when not operating, and that the price for non spinning reserves could be lower in such hours. As an example, the LMS 100 units in Long Island earn just under \$ 4 per KW in non spinning reserve revenue, the LMS 100 unit earn just under \$6 per KW in non spinning reserve revenues and the values for Zones G to J and Zone F are around \$ 7.00 per KW. These values are at the minimum required capacity level plus 190 MW. Ancillary Service revenues vary with the dispatch and excess level under this method. The Zone C LMS 100 earns only \$ 0.27 cents per KW year in Ancillary Service revenue from 10 minute non spinning reserve revenues. NYISO indicated that VSS revenues in the west would likely be zero. S&L has determined that the LMS 100 units can start in 10 minutes; however, the SCR will not achieve full emissions compliance until approximately 20 minutes after start. The units would need an allowance for start-up emissions to operate this way, but we have assumed that this could be obtained as the alternative - to have older units without SCRs provide the service - would lead to higher emissions when such units were called to start.

At the time the model run prepared for this report was finalized, information on combined cycle Ancillary Service revenues was still under development. Based on initial data provided by NYISO, we assumed that a combined cycle unit could earn \$ 7 per KW year, albeit in large part from spinning reserve and regulation revenue as opposed to non spinning reserve revenue. For the sensitivity case where the CC in NYC runs less, but gets tax abatement, the Ancillary Service value was reduced to \$ 3.50 per KW year, as combined cycle units earn Ancillary Service revenues when they are operating at reduced load, which would not happen if operations were

[limited to 18 hours per start. Additionally, for all units we have added a Schedule 1 Ancillary Service cost of \\$ 0.27 per MWH to the operating cost prior to the dispatch analysis and profit calculations. The STATA analysis showing the computation of factors for the LMS 100 and CC units have been posted to the NYISO website.](#)

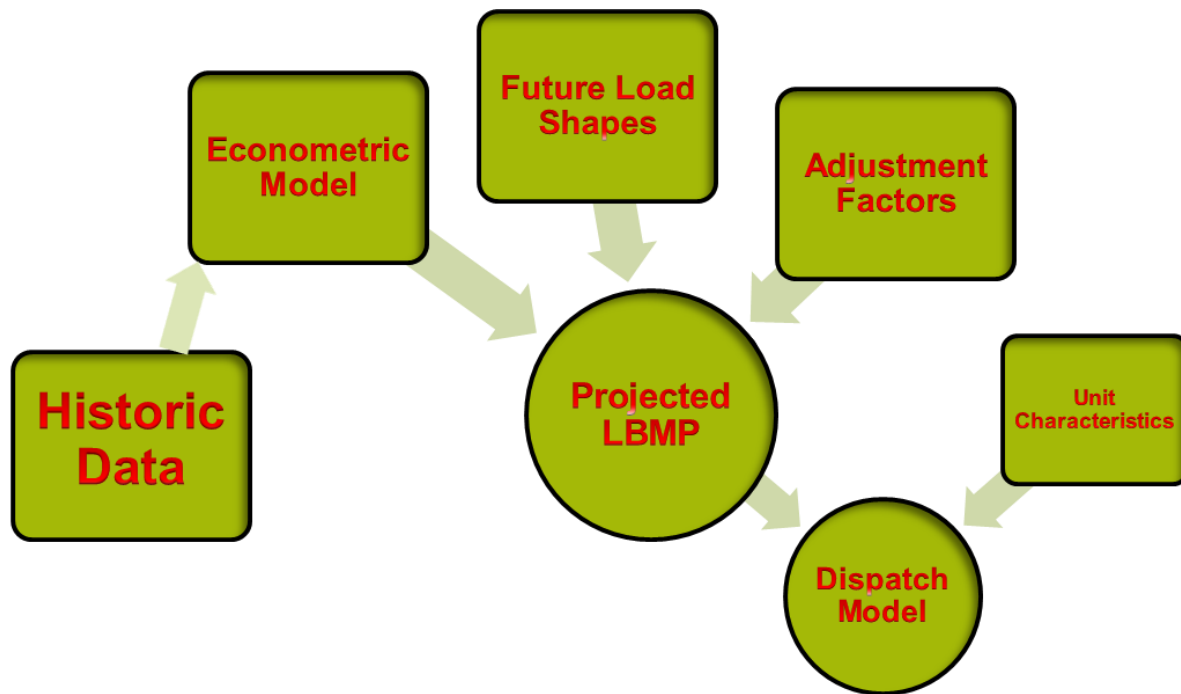
{NTD – CC estimates are preliminary, but we do not expect significant changes.}

E. Results

The net energy revenue results, excluding Ancillary Services revenues, are summarized in the NERA Excel Demand Curve Model, on the tab labelled “Energy Curve Raw.” Presented are the plant type and region, the margin above or below the capacity requirement, and aggregate net revenues, which can be broken down into real-time and net day-ahead revenues, where start-up costs are netted out of gross net revenues. The value for “profit” is the annual net energy operating revenue estimated per MW per year assuming constant annual capability. The adjustments further made to these values are as follows: 1) the values are multiplied by the average of the summer and winter capability over the ICAP capability to adjust for the fact that all costs are stated per kW of ICAP and the plant will participate in energy markets at higher levels; 2) profits are reduced by the Equivalent Demand Forced Outage Rate (EFORd); and, 3) the Ancillary Services revenues are added to the energy profits. ~~NTD—We expect that the complete~~[The energy results will be available by April 22. At that time, after NYISO review, the NERA Excel model used to develop the Demand Curve Model will be in this report has been posted to the NYISO website.](#)

F. Calibration

We have attempted to ensure that the energy and ancillary service revenues we derive are reasonable through a series of calibration checks. All of the feasible calibrations are at best partial, checking one aspect of the entire process against another. Schematically, the full process is described in the following figure:



The historic data is used as an input to the econometric model, which, combined with the future load shapes and various adjustment factors (zonal-to-nodal, resource mix adjustment and excess adjustment) are combined to produce future year LBMPs. These LBMPs are then combined with the unit characteristics to produce energy and ancillary service revenues.

We have produced energy revenues using three different sources for LBMPs:

- a) Historic prices with no adjustments
- b) The econometric model adjusted for future load shape with no other adjustments

c) The final set of LBMPs after all adjustments.

This will yield three different set of projected net energy revenues in each of five relevant zones (NYC, LI, HV, Central, Capital) for each of two technologies (LMS100 and CCGT). These profits can then be compared with the MMU estimates of profits for each of these technologies. The results of these comparisons are presented in the following table:

Estimates of Net Energy and Ancillary Service Revenues

Using Three Sources for LBMP Projections

	<u>LMS100</u>					<u>CCGT</u>				
	<u>LI</u>	<u>NYC</u>	<u>LHV</u>	<u>CPTL</u>	<u>CNTR</u>	<u>LI</u>	<u>NYC</u>	<u>LHV</u>	<u>CPTL</u>	<u>CNTR</u>
	-	-	-	-	-	-	-	-	-	-
	<u>Based on Actual LBMPs</u>									
<u>2010</u>	<u>74.62</u>	<u>49.30</u>	<u>38.29</u>	<u>28.04</u>	<u>16.56</u>	<u>126.85</u>	<u>88.33</u>	<u>81.80</u>	<u>68.30</u>	<u>36.88</u>
<u>2011</u>	<u>74.40</u>	<u>43.35</u>	<u>35.82</u>	<u>25.80</u>	<u>19.04</u>	<u>136.70</u>	<u>91.06</u>	<u>83.56</u>	<u>60.11</u>	<u>39.16</u>
<u>2012</u>	<u>94.74</u>	<u>33.43</u>	<u>26.87</u>	<u>13.69</u>	<u>15.29</u>	<u>148.04</u>	<u>80.18</u>	<u>67.43</u>	<u>41.54</u>	<u>55.17</u>
<u>Average</u>	<u>81.25</u>	<u>42.03</u>	<u>33.66</u>	<u>22.51</u>	<u>16.96</u>	<u>137.20</u>	<u>86.52</u>	<u>77.60</u>	<u>56.65</u>	<u>43.74</u>
	-	-	-	-	-	-	-	-	-	-
	<u>Based on Regression Prior to Any MAPS Adjustments</u>									
<u>2014-2015</u>	<u>113.80</u>	<u>53.38</u>	<u>45.00</u>	<u>30.70</u>	<u>26.25</u>	<u>188.59</u>	<u>93.53</u>	<u>79.88</u>	<u>64.73</u>	<u>59.21</u>
<u>2015-2016</u>	<u>116.52</u>	<u>54.98</u>	<u>46.42</u>	<u>30.95</u>	<u>26.75</u>	<u>192.27</u>	<u>95.21</u>	<u>81.28</u>	<u>65.52</u>	<u>59.81</u>
<u>2016-2017</u>	<u>120.10</u>	<u>56.71</u>	<u>47.92</u>	<u>31.77</u>	<u>27.40</u>	<u>198.30</u>	<u>99.42</u>	<u>84.83</u>	<u>68.14</u>	<u>62.03</u>
<u>Average</u>	<u>116.81</u>	<u>55.02</u>	<u>46.45</u>	<u>31.14</u>	<u>26.80</u>	<u>193.05</u>	<u>96.05</u>	<u>82.00</u>	<u>66.13</u>	<u>60.35</u>
	-	-	-	-	-	-	-	-	-	-
	<u>Estimates by MMU</u>									
<u>2010/11/12</u>										
<u>Average</u>	<u>98.16</u>	<u>40.61</u>	<u>38.53</u>	<u>9.98</u>	<u>na</u>	<u>164.65</u>	<u>88.49</u>	<u>90.72</u>	<u>73.73</u>	<u>na</u>
	-	-	-	-	-	-	-	-	-	-
	<u>Based on Regression Adjusted by MAPS Factor for Resource Mix and 190MW Excess</u>									
<u>2014-2015</u>	<u>94.56</u>	<u>39.86</u>	<u>32.19</u>	<u>22.44</u>	<u>17.07</u>	<u>165.62</u>	<u>73.85</u>	<u>61.68</u>	<u>49.70</u>	<u>39.50</u>
<u>2015-2016</u>	<u>96.72</u>	<u>40.91</u>	<u>33.34</u>	<u>23.05</u>	<u>17.53</u>	<u>168.94</u>	<u>75.21</u>	<u>62.90</u>	<u>50.43</u>	<u>39.65</u>
<u>2016-2017</u>	<u>99.95</u>	<u>41.82</u>	<u>34.25</u>	<u>23.41</u>	<u>17.97</u>	<u>174.71</u>	<u>78.74</u>	<u>66.00</u>	<u>52.73</u>	<u>41.38</u>
<u>Average</u>	<u>118.20</u>	<u>53.79</u>	<u>45.82</u>	<u>31.64</u>	<u>29.53</u>	<u>192.89</u>	<u>99.82</u>	<u>80.73</u>	<u>64.65</u>	<u>67.60</u>

V.IV. Developing the Demand Curves and Calculating Carrying Charges

A. Approach Overview

The Demand Curve Model is designed to find the annual cost of new entry (CONE) at the reference point that will provide for the full recovery of capital costs over a thirty-year capital recovery period, using the financial assumptions of a 50%/50% capital structure and 6.50%/12.00% debt/equity cost. The CONE consists of two components. The first component is an implied annual capital cost that will provide for the full recovery described above, recognizing that there will be a tendency to clear at capacity values above the reference value and at prices below the reference value, as well as a tendency in the long term to earn energy revenues consistent with a degree of excess capacity. The second component is an energy revenue offset based on energy revenues over the three-year reset period, assuming capacity levels at the minimum required level⁵² plus the capacity of the hypothetical peaking plant.

The model allows for a wide array of scenarios by incorporating numerous variables that can be changed to accommodate different market conditions, target levels of capacity, and Demand Curve shapes (intercept and shape). In addition, two types of generator units (the LMS100 and a combined cycle unit) can be simulated. This flexibility allows the user to compare the effect of a variable over multiple scenarios. The combined cycle unit is presented for informational purposes. The model includes results for the New Capacity Zone (G to J Locality) that is proposed to be established for the reset period.

The model reports the CONE at the reference point, the implied annual capital cost, the carrying charge and the implied amortization period. The zero crossing point affects all of these values. A lower zero crossing point (i.e., closer to 100%) produces a shorter amortization period and higher carrying charge, as demand revenues go down faster for a given level of excess capacity.

Many of the inputs to the Demand Curve Model requirements are based on judgment. The inputs used will be described below. As a result of the judgmental nature of the inputs, it is important to note that in selecting inputs, we are guided also by the result produced. The results produced using the [current recommended](#) shape and slope of the Demand [Curve Curves](#) show implied amortization

⁵² We sometimes will use the term target when referring to the minimum required level of installed capacity.

periods of ~~just over xx years in ROS, just over ww~~22.5 years in the LHV, ~~just over yy~~Capital and Central zones, 20.5 years in Zones G to J, 15.5 years in NYC and ~~just over zz~~20.5 years in LI.-

These results reflect measurable, but not extreme implied merchant risks. Were the zero crossing points closer to the origin, the amortization periods would decrease, raising the reference point to reflect added merchant risk. ~~{NTD—values to be inserted after analysis is complete}~~The zero crossing point is not only the factor affecting the implied amortization period. The period increases as more revenue is earned from the energy market as opposed to the capacity market because the change in energy revenues as a result of capacity excesses is less than the change in capacity revenues. The period also decreases as the ICR/LCR increases in MW terms relative to the size of the proxy plant. The implied amortization periods reflect all these factors. When all factors are considered, the amortization periods of 22.5 years in ROS and 20.5 years in Long Island are similar. NYC has the lowest implied amortization period at 15.5 years.

B. Financial Parameters

The development of financial parameters, including the capital structure and costs of capital, is an issue over which stakeholders hold multiple and sharply conflicting perspectives. NERA's review with stakeholders began at the March 11, 2013 ICAP Working Group meeting, where NERA proposed using a weighted average nominal pre-tariff cost of capital (WACC) of 9.25% for merchant generators to establish the Demand Curve. This WACC is based on an assumed corporate capital structure for a generation company, consisting 50% debt and 50% equity with a 6.5% cost of debt and a 12% cost of equity. The cost of capital estimate is premised on the assumption that the merchant generator is able to finance the hypothetical peaking plant at the corporate level, and will consider the investment as part of diversified portfolio with exposure to different geographic markets.

The cost of debt is based upon a range of observed yields for companies in the industry that range from 2.71%¹ to 7.41%, and recognizing that BB and BBB rated corporate bonds are yielding approximately 4.98% and 3.43% respectively as of February 19, 2013. Our recommendation recognizes the fact that several merchant generators currently fall at the lower end of the speculative-grade ratings level, and that the yields cited above are for bond indices where the average duration of the underlying bonds is 7 to 10 years. Bond financing of a longer duration

would carry a higher yield. The selection of 6.5% reflects the yield on long duration (15 to 25) year bonds that are currently outstanding.

The recommended cost of equity is derived using the capital asset pricing model (CAPM). The CAPM relies upon a risk-free rate of 3.18% (30-year US treasury yield as of February 18, 2013)⁵³ and an equity beta of 1.2. This is the same beta used in the prior demand curve resets. Due to consolidation in the industry, NERA did not update the beta, as the small sample size this year was overly limiting. [While comments on the initial draft have requested an update of the beta, NERA does not see that as advisable given the current small sample size of trade merchant generation companies.](#) A market risk premium of 6.62% was used in the CAPM calculation.⁵⁴ The recommended 12% return on equity is above the calculated cost of equity of 11.12 %. The rationale for this recommendation is the inherent riskiness of the merchant generation sector relative to the more stable price-regulated electricity businesses whose current allowed return on equity (ROEs) tend to fall in the 10% to 11% range. With merchant power plants posing greater investment risks to investors, the generation sector has always carried a risk premium relative to regulated utilities. At the working group meeting, it was noted that regulated utilities in New York are allowed lower returns than regulated utilities in other states. NERA considered this feedback and continues to believe that the assumed return on equity of 12% is reasonable, since it provides an appropriate risk premium relative to the price-regulated firms against whom merchant generators broadly compete to raise capital. Indicative data on the cost of capital for regulated entities is provided in the table below as a point of reference.

⁵³ Federal Reserve Statistical Release. Selected Interest Rates. <http://www.federalreserve.gov/releases/h15/update/>.

⁵⁴ Ibbotson Associates Stocks, Bonds, Bills and Inflation 2012 Yearbook. (Long Horizon Equity Risk Premium from 1926 to 2011).

Returns for Price-Regulated Public Utilities Compared to NERA Assumption for Merchant

	ROE	Common Equity Ratio
State-Regulated Electric Utility	10.15	50.55
State-Regulated Gas Utility	9.94	51.33
FERC Regulated Electric Utility	10.81 (without incentives) 12.32 (with incentives)	
Demand Curve Merchant Assumption	12.00	50%

Notes & Sources: The state-regulated returns and common equity ratios have been obtained from Regulatory Research Associates, *Major Rate Cases – 2012*. Regulatory Research Associates is a division of SNL Energy. The FERC-regulated electric allowed ROEs were obtained from the individual FERC orders in recent electricity transmission rate cases including: *RITELine Illinois, LLC*, 137 FERC ¶ 61,039 (2011), *Desert Southwest Power, LLC*, 135 FERC ¶ 61,143 (2011), *Northern Pass Transmission LLC*, 134 FERC ¶ 61,095 (2011), *Central Maine Power Co.*, 135 FERC ¶ 61,136 (2011), *New England Conference of Public Utilities Commissioners, Inc. v. Bangor Hydro-Electric Co.*, 135 FERC ¶ 61,140 (2011), *Green Power Express LP*, 135 FERC ¶ 61,141 (2011), *Ameren Services Co.*, 135 FERC ¶ 61,142 (2011), *Atlantic Grid Operations A LLC*, 135 FERC ¶ 61,144 (2011), *Central Transmission, LLC*, 135 FERC ¶ 61,145 (2011), *Pepco Holdings, Inc.*, 124 FERC ¶ 61,176 (2008), and *Bangor Hydro-Electric Co.*, 111 FERC ¶ 63,048 (2005).

In prior Demand Curve resets, generators have taken issue with NERA's election to base the cost of capital on a corporate capital structure rather than a stand-alone project financing. This reset, NERA received similar comments, together with comments that the merchant cost of capital should consider risks specific to New York, and the potential for concentration of those risks in a single project or set of projects. We address each consideration in turn.

Corporate versus project financing – We believe that in equilibrium conditions a merchant generator project would most efficiently be financed on balance sheet as part of a larger corporate entity, rather than as a stand-alone project entity. In the current capital market conditions, a merchant project would not be financed most economically as a stand-alone project. Project financing would likely require a long term contract with a credit worthy counterparty, which would likely be an entity with ratepayer support and hence not merchant. NERA reviewed the financing costs for stand-alone merchant projects, as reported in Project Finance magazine, and observed for facilities with merchant characteristics very high financing cost (premiums of 700 to 900 basis points above LIBOR), low \$/kW loan levels and tenors of less than ten years. These assumptions

would lead to extremely high estimates of CONE, which would be correct assuming project financing, but would not represent the most economical form of entry, which is a corporately financed facility. As a result, we believe the appropriate point for determining financing assumptions is to consider the capital structure and cost of capital for a publicly traded corporation with an unregulated generation portfolio. We also note that the FERC has accepted this approach both in previous NYISO Demand Curve resets. **Risks Specific to New York and Undiversified Generators** – As stated at the outset of this section, we believe it is unreasonable for the purposes of defining financial assumptions to consider a single power plant in isolation. Diversification across fuel types, technologies and geographic markets reduces risks for investors in the sector. A core premise of the CAPM, the model we have chosen to model the cost of equity, is that investors only require a higher risk adjusted return for risks that cannot be diversified away. As such, we do not believe it is appropriate to set the Demand Curve assuming risks are concentrated in an undiversified single facility or group of facilities without the benefit of diversification.

The assumption NERA makes for the cost of equity provides a reasonable premium over less risky investments to accommodate the risks borne by investors in merchant power plants. In addition, the way NERA has structured the Demand Curve model has factored in certain specific risk factors faced by generators including:

- The tendency toward excess capacity integrated with the slope of the Demand Curve;
- The risk of regulatory intervention resulting in lower clearing prices than that determined by market forces; and,
- Technological improvement trends.

These risks are specifically accounted for, and are in addition to risk reflected in the assumed debt and equity cost levels. On balance, we believe this approach provides a reasonable solution for the establishment of the Demand Curve reset parameters. In the last reset we used a zero probability that regulatory intervention would result in a lower clearing price for capacity than that determined by market forces. We have revisited that assumption and, as will be explained later, recommend reflecting such risk in the reset with a non-zero probability.

The specific components of the WACC calculation are detailed below:

Developing the Demand Curves and Calculating Carrying Charges

Debt/Capital	50%
Debt Cost	6.50%
Asset Beta	0.60
Equity Beta	1.20
Equity Risk Premium	6.62%
Risk-Free Rate (30 yr)	3.18%
Calculated Cost of Equity	11.12%
Recommended Equity Cost	12.00%
WACC	9.25%
Tax Rate (illustrative)	40.0%

To illustrate the consistency of these assumptions with the financial characteristics of entities that operate in the generation sector, we provide sample financial statistics for such entities below.

Sample Leverage Ratios for Power Generators

COMPANY	TOTAL DEBT TO TOTAL CAPITAL	DEBT TO ENTERPRISE VALUE
NRG ENERGY INC	55%	62%
PUBLIC SERVICE ENTERPRISE GP	44	35
AES CORP	70	71
TRANSALTA CORP	53	
CALPINE CORP	70	58
EXELON CORP	47	44
DOMINION RESOURCES INC/VA	66	40
TRANSCANADA CORP	55	

COMPANY	TOTAL DEBT TO TOTAL CAPITAL	DEBT TO ENTERPRISE VALUE
NRG ENERGY INC	55%	62%
PUBLIC SERVICE ENTERPRISE GP	44	35
AES CORP	70	71
TRANSALTA CORP	53	
CALPINE CORP	70	58
EXELON CORP	47	44
DOMINION RESOURCES INC/VA	66	40
TRANSCANADA CORP	55	

Sample Debt Costs for Power Generators

Company	Ticker	Mty Type	Crncy	Bid Yld to Mty	Amount Issued	Collateral Type	Issue Date	Mty(Yrs from 2day)
AES Corp/VA	AES	CALLABLE	USD	5.50	1,000,000,000	SR UNSECURED	6/15/2011	8.35
AES Corp/VA	AES	CALLABLE	USD	5.50	1,000,000,000	SR UNSECURED	6/15/2011	8.35
AES Corp/VA	AES	CALLABLE	USD	5.45	999,500,000	SR UNSECURED	8/1/2012	8.35
AES Corp/VA	AES	CALLABLE	USD	5.39	625,000,000	SR UNSECURED	5/20/2009	7.27
Allegheny Energy Supply Co LLC	FE	CALLABLE	USD	6.35	250,000,000	SR UNSECURED	10/1/2009	26.64
Allegheny Energy Supply Co LLC	FE	CALLABLE	USD	6.35	250,000,000	SR UNSECURED	10/1/2009	26.64
Allegheny Energy Supply Co LLC	FE	CALLABLE	USD	3.81	350,000,000	SR UNSECURED	10/1/2009	6.64
Allegheny Energy Supply Co LLC	FE	CALLABLE	USD	3.81	350,000,000	SR UNSECURED	10/1/2009	6.64
Calpine Corp	CPN	CALLABLE	USD	6.50	1,200,000,000	SR SECURED	1/14/2011	9.89
Calpine Corp	CPN	CALLABLE	USD	6.45	1,200,000,000	SR SECURED	1/14/2011	9.89
Calpine Corp	CPN	CALLABLE	USD	6.25	2,000,000,000	SR SECURED	10/22/2010	7.98
Calpine Corp	CPN	CALLABLE	USD	6.19	2,000,000,000	SR SECURED	10/22/2010	7.98
Calpine Corp	CPN	CALLABLE	USD	6.32	1,100,000,000	SR SECURED	7/23/2010	7.44
Calpine Corp	CPN	CALLABLE	USD	5.74	1,100,000,000	SR SECURED	7/23/2010	7.44
Calpine Corp	CPN	CALLABLE	USD	6.81	400,000,000	SR SECURED	5/25/2010	6.48
Calpine Corp	CPN	CALLABLE	USD	6.81	400,000,000	SR SECURED	5/25/2010	6.48
CE Generation LLC	CEGENE	CALL/SINK	USD	7.41	400,000,000	SR SECURED	3/6/2000	5.81
Exelon Generation Co LLC	EXC	CALLABLE	USD	5.14	788,203,000	SR UNSECURED	6/18/2012	29.31
Exelon Generation Co LLC	EXC	CALLABLE	USD	5.14	788,203,000	SR UNSECURED	6/18/2012	29.31
Exelon Generation Co LLC	EXC	CALLABLE	USD	5.06	788,203,000	SR UNSECURED	2/12/2013	29.31
Exelon Generation Co LLC	EXC	CALLABLE	USD	5.12	350,000,000	SR UNSECURED	9/30/2010	28.61
Exelon Generation Co LLC	EXC	CALLABLE	USD	5.12	900,000,000	SR UNSECURED	9/23/2009	26.60
Exelon Generation Co LLC	EXC	CALLABLE	USD	3.68	523,303,000	SR UNSECURED	6/18/2012	9.31
Exelon Generation Co LLC	EXC	CALLABLE	USD	3.68	523,303,000	SR UNSECURED	6/18/2012	9.31
Exelon Generation Co LLC	EXC	CALLABLE	USD	3.68	523,303,000	SR UNSECURED	2/12/2013	9.31
Exelon Generation Co LLC	EXC	CALLABLE	USD	3.30	550,000,000	SR UNSECURED	9/30/2010	7.61
Exelon Generation Co LLC	EXC	CALLABLE	USD	3.07	600,000,000	SR UNSECURED	9/23/2009	6.60

Developing the Demand Curves and Calculating Carrying Charges

Company	Ticker	Mty Type	Crcy	Bid Yld to Mty	Amount Issued	Collateral Type	Issue Date	Mty(Yrs from 2day)
AES Corp/VA	AES	CALLABLE	USD	5.50	1,000,000,000	SR UNSECURED	6/15/2011	8.35
AES Corp/VA	AES	CALLABLE	USD	5.50	1,000,000,000	SR UNSECURED	6/15/2011	8.35
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Allegheny Energy Supply Co LLC	FE	CALLABLE	USD	6.35	250,000,000	SR UNSECURED	10/1/2009	26.64
Allegheny Energy Supply Co LLC	FE	CALLABLE	USD	3.81	350,000,000	SR UNSECURED	10/1/2009	6.64
Allegheny Energy Supply Co LLC	FE	CALLABLE	USD	3.81	350,000,000	SR UNSECURED	10/1/2009	6.64
Calpine Corp	CPN	CALLABLE	USD	6.50	1,200,000,000	SR SECURED	1/14/2011	9.89
Calpine Corp	CPN	CALLABLE	USD	6.45	1,200,000,000	SR SECURED	1/14/2011	9.89
Calpine Corp	CPN	CALLABLE	USD	6.25	2,000,000,000	SR SECURED	10/22/2010	7.98
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Calpine Corp	CPN	CALLABLE	USD	5.74	1,100,000,000	SR SECURED	7/23/2010	7.44
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Exelon Generation Co LLC	EXC	CALLABLE	USD	5.14	788,203,000	SR UNSECURED	6/18/2012	29.31
Exelon Generation Co LLC	EXC	CALLABLE	USD	5.14	788,203,000	SR UNSECURED	6/18/2012	29.31
Exelon Generation Co LLC	EXC	CALLABLE	USD	5.06	788,203,000	SR UNSECURED	2/12/2013	29.31
Exelon Generation Co LLC	EXC	CALLABLE	USD	5.12	350,000,000	SR UNSECURED	9/30/2010	28.61
Exelon Generation Co LLC	EXC	CALLABLE	USD	5.12	900,000,000	SR UNSECURED	9/23/2009	26.60
Exelon Generation Co LLC	EXC	CALLABLE	USD	3.68	523,303,000	SR UNSECURED	6/18/2012	9.31
Exelon Generation Co LLC	EXC	CALLABLE	USD	3.68	523,303,000	SR UNSECURED	6/18/2012	9.31
Exelon Generation Co LLC	EXC	CALLABLE	USD	3.68	523,303,000	SR UNSECURED	2/12/2013	9.31
Exelon Generation Co LLC	EXC	CALLABLE	USD	3.30	550,000,000	SR UNSECURED	9/30/2010	7.61
Exelon Generation Co LLC	EXC	CALLABLE	USD	3.07	600,000,000	SR UNSECURED	9/23/2009	6.60

Sample Debt Costs for Power Generators (Continued)

Company	Ticker	Mty Type	Crncy	Bid Yld to Mty	Amount Issued	Collateral Type	Issue Date	Mty(Yrs from 2day)
PPL Energy Supply LLC	PPL	CALLABLE	USD	5.27	300,000,000	SR UNSECURED	12/14/2006	23.81
PPL Energy Supply LLC	PPL	CALLABLE	USD	3.76	712,415,000	SR UNSECURED	12/16/2011	8.81
PPL Energy Supply LLC	PPL	CALLABLE	USD	2.71	400,000,000	SR UNSECURED	3/14/2008	5.19
PSEG Power LLC	PEG	CALLABLE	USD	4.89	499,720,700	COMPANY GUARNT	12/10/2001	18.14
PSEG Power LLC	PEG	CALLABLE	USD	4.88	500,000,000	COMPANY GUARNT	4/16/2001	18.14
PSEG Power LLC	PEG	CALLABLE	USD	4.88	500,000,000	COMPANY GUARNT	4/16/2001	18.14
PSEG Power LLC	PEG	CALLABLE	USD	3.25	250,000,000	COMPANY GUARNT	9/19/2011	8.56
PSEG Power LLC	PEG	CALLABLE	USD	3.06	406,004,000	COMPANY GUARNT	4/5/2010	7.14
PSEG Power LLC	PEG	CALLABLE	USD	3.06	406,004,000	COMPANY GUARNT	4/5/2010	7.14
PSEG Power LLC	PEG	CALLABLE	USD	2.95	406,004,000	COMPANY GUARNT	8/11/2010	7.14
TransAlta Corp	TACN	CALLABLE	USD	6.32	300,000,000	SR UNSECURED	3/12/2010	27.06
TransAlta Corp	TACN	AT MATURITY	CAD	6.66	141,100,000	SR UNSECURED	11/15/2005	17.73
TransAlta Corp	TACN	CALLABLE	CAD	6.61	110,000,000	SR UNSECURED	10/22/1999	16.66
TransAlta Corp	TACN	CALLABLE	USD	4.30	400,000,000	SR UNSECURED	11/7/2012	9.73
TransAlta Corp	TACN	AT MATURITY	CAD	4.37	400,000,000	SR UNSECURED	11/18/2009	6.74
TransAlta Corp	TACN	CALLABLE	USD	3.50	500,000,000	SR UNSECURED	5/9/2008	5.22

Company	Ticker	Mty Type	Crncy	Bid Yld to Mty	Amount Issued	Collateral Type	Issue Date	Mty(Yrs from 2day)
PPL Energy Supply LLC	PPL	CALLABLE	USD	5.27	300,000,000	SR UNSECURED	12/14/2006	23.81
PPL Energy Supply LLC	PPL	CALLABLE	USD	3.76	712,415,000	SR UNSECURED	12/16/2011	8.81
PPL Energy Supply LLC	PPL	CALLABLE	USD	2.71	400,000,000	SR UNSECURED	3/14/2008	5.19
PSEG Power LLC	PEG	CALLABLE	USD	4.89	499,720,700	COMPANY GUARNT	12/10/2001	18.14
PSEG Power LLC	PEG	CALLABLE	USD	4.88	500,000,000	COMPANY GUARNT	4/16/2001	18.14
PSEG Power LLC	PEG	CALLABLE	USD	4.88	500,000,000	COMPANY GUARNT	4/16/2001	18.14
PSEG Power LLC	PEG	CALLABLE	USD	3.25	250,000,000	COMPANY GUARNT	9/19/2011	8.56
PSEG Power LLC	PEG	CALLABLE	USD	3.06	406,004,000	COMPANY GUARNT	4/5/2010	7.14
PSEG Power LLC	PEG	CALLABLE	USD	3.06	406,004,000	COMPANY GUARNT	4/5/2010	7.14
PSEG Power LLC	PEG	CALLABLE	USD	2.95	406,004,000	COMPANY GUARNT	8/11/2010	7.14
TransAlta Corp	TACN	CALLABLE	USD	6.32	300,000,000	SR UNSECURED	3/12/2010	27.06
TransAlta Corp	TACN	AT MATURITY	CAD	6.66	141,100,000	SR UNSECURED	11/15/2005	17.73
TransAlta Corp	TACN	CALLABLE	CAD	6.61	110,000,000	SR UNSECURED	10/22/1999	16.66
TransAlta Corp	TACN	CALLABLE	USD	4.30	400,000,000	SR UNSECURED	11/7/2012	9.73
TransAlta Corp	TACN	AT MATURITY	CAD	4.37	400,000,000	SR UNSECURED	11/18/2009	6.74
TransAlta Corp	TACN	CALLABLE	USD	3.50	500,000,000	SR UNSECURED	5/9/2008	5.22

Source: Bloomberg Finance, L.P.

Our scope of work calls for us to identify the inflation rate consistent with our development of CONE and financing assumptions. For this task we have utilized the First Quarter 2013 Survey of Professional Forecasters, assembled and published by the Philadelphia Federal Reserve Bank.⁵⁵

⁵⁵ <http://www.phil.frb.org/research-and-data/real-time-center/survey-of-professional-forecasters/2013/survq113.cfm>

The long term CPI median forecast is a rate of 2.3%. Embedded in that rate is a rate of 2.0% for 2103, 2.2% for 2014 and 2.3 % for 2015. ~~Given the similarity between the near term and long term rates, we~~We recommend that 2.3% be used ~~both~~ as the long term inflation rate consistent with the financing cost assumptions, and 2.2% be used as the short term inflation rate used to escalate the Demand Curve over the reset period. We have utilized the 2.2% rate in this report as the short term inflation rate.

C. Model Description

The Demand Curve Model works by simulating revenues and expenditures given a set of input parameters, energy functions, zone and type of unit. The revenues are cash flows that the owner of a new unit would expect to receive over the thirty-year economic life of the unit. Similarly, the expenditures represent expenses and the required return on equity and debt. The Model solves for the Demand Curve by finding capacity payments (also referred to as demand payments in the model) that satisfy the zero supernormal profit criteria (revenues equal expenditures). Supernormal net revenues are those above the cost of equity capital.

A new generating unit can expect to receive revenues from two main sources. Energy and Ancillary Service net revenues represent sales in the NYISO energy and Ancillary Service markets. The model uses the user-defined expected value and standard deviation of supply to generate 100 possible values for capacity. These capacity values are put through an energy and ancillary service net revenue function. The function is zone and unit-specific and calculates expected energy and ancillary services net revenue given a level of supply. The revenues will be lower when there is surplus capacity, and higher when there is not enough capacity. The model is designed to simulate this scenario and to adjust the Demand Curve so that, given an expectation of surplus capacity, the new entrant will be able to fully recover costs over thirty years. The mean assumed level of excess capacity is set as the MW capacity of the hypothetical peaking plant. As discussed previously, net energy revenues are derived from a combined econometric and GE MAPS modeling approach.

Demand Curve payments approximate payments the owner of a new unit could expect to receive through NYISO ICAP Spot Market Auctions. Like the Energy and Ancillary Service payments, they are determined through a Monte Carlo analysis. User-defined parameters are used to

determine possible values for supply in the auction from which an expected capacity value payment is derived. Since these payments are simulated by the Demand Curve, which is also an output of the Model, the demand payments are endogenous to the Model. The model includes a Summer Capability Period and Winter Capability Period demand simulator. We compute Summer and Winter demand revenues using the NYISO formula to adjust the annual Demand at Reference to a Demand Curve Monthly value. We then simulate forecast demand revenues against this curve clearing at Summer and Winter capacity values. The Summer to Winter capacity ratios (WSRs) for NYCA and each locality reflect ~~the~~ values for WSRs in the relevant locations that are consistent with ~~the assumed average levels of excess capacity used~~ a [Deliverability Study performed by NYISO for this report and also consistent with FERC's final order in the prior Demand Curve reset proceeding. The spreadsheet developing the factors has been posted](#) to ~~calculate the other components of net CONE.~~ [\[NTD—WSRs NYISO website. The factors for each zone are being developed\]](#) as follows:

<u>NYC</u>	<u>G-J</u>	<u>LI</u>	<u>NYCA/ROS</u>
<u>1.0863</u>	<u>1.0675</u>	<u>1.0676</u>	<u>1.0540</u>

Expenditures are fixed O&M, property tax and insurance, and levelized fixed charges (carrying charge). Fixed O&M and property tax and insurance are defined by input parameters and the cost of new entry. The carrying charge is calculated by Sargent & Lundy assuming a 50% debt share cost of capital at 6.50% and a 50% equity share at 12.00%.

From these revenues and expenditures, a Demand Curve is derived such that revenues equal expenditures (binding constraint). As the Demand Curve in part determines demand payments, which is one of the sources of revenue, the model solves for both using a goal seek.

Once the model solves for the Demand Curve, it calculates net revenues as percentage of the cost of new entry. The model then looks up the amortization period that matches this percentage in the

table of levelized fixed charges. The real levelized carrying charge is determined using this amortization period.⁵⁶

While the approach is complex, we believe the complexity is necessary. Although a new peaking plant will likely physically last thirty years or more, investors will use a shorter time horizon in determining the levelized cost. PJM uses a single assumption of 20 years in setting CONE. A single assumption is not suitable for the NYISO as the NYISO is commonly acknowledged by stakeholders to have a bias toward excess and that bias presents different risk depending upon the shape and slope of the Demand Curve. Hence, we believe that a model that considers the interaction between the Demand Curve shape and slope and the amortization period is required.

D. Model Inputs

The model's thirty plus variables can be broken down into the following categories: Demand Curve, Technological Progress, Plant, Residual Value, Monte Carlo, Regulatory Risk, Net Energy and Ancillary Services (AS) revenues, Property Taxes and Deliverability. Each of these categories is explained in more detail below.

Demand Curve variables determine the x-axis intercept of the curve and can also be used to kink the Demand Curve.

As [discussed in the Executive Summary and](#) described [in more detail](#) later, we believe that it is appropriate to ~~continue using~~[retain](#) the ~~existing~~ shape ~~and of the current Demand Curves and move~~ the zero crossing ~~point and use 4 yypoints toward levels consistent with the reliability analysis~~ conducted by NYISO and FTI. We recommend using 113.5% for NYCA, ~~1xx115%~~ for the ~~Lower Hudson Valley, 1wwG-J Zone, 116.5%~~ for NYC and ~~1zz118%~~ for LI. ~~{NTD—Analysis of zero crossing point is not complete at time of this draft. NERA will need to complete energy analysis and examine model results and will consider FTI report before recommending these parameters.}~~

Technological progress variables can be used to determine how the real cost of a technology increases or decreases over time. We use a factor of 0.25 percent. We base this on the 2012 U.S.

⁵⁶ As will be described below, the model has been expanded to allow the user to input a vector of property taxes. When used in this mode, the model can produce the correct value for the demand at reference, but does not have the information to report the amortization rate correctly.

DOE Energy Information Agency Annual Energy Outlook which has minimum learning factors for advanced combustion turbines and advanced combined cycles of about 0.5% per year through 2025.⁵⁷ We discount the value to 0.25% to reflect other factors that could offset decreases in technology costs.

Plant variables determine the location, type and performance of the generating unit and are used to select the appropriate cost of new entry from those provided by Sargent & Lundy.

Residual value is the value of the unit at the end of the thirty-year life. For both the LMS 100 and the combined cycle unit, we use a residual value of 5% of the initial investment adjusted for inflation. This is the same value assumed in the prior reset.

Monte Carlo variables used to calculate expected values for Capacity payments and Energy and Ancillary Service revenue. These values are the assumed level of excess and the standard deviation of that excess. For the assumed level of excess we use the capacity of the hypothetical peaking plant divided by the minimum installed capacity level for each locality and or for NYCA. When analyzing a combined cycle we utilize the capacity of the hypothetical combined cycle unit. For the standard deviation we assume 50% of the level of assumed excess consistent with prior reset assumptions.

~~**Regulatory Risks**—In the prior reset we noted that the Demand Curve was then in place for seven years and did not appear to have been artificially suppressed by arbitrary intervention. Hence, we recommended that an adjustment for such risk not be added—i.e., that a zero probability be assumed. In ICAP Working Group meetings it has been noted that uneconomic entry faces a mitigation bidding value equal to 75% of net Cone and that the State of New York is actively considering through the Energy Highway initiative the development of resources that may be in addition to what market forces would lead to. While, it is not clear that any such actions will result from this initiative, we do recommend that this possibility be at least considered. Hence we use in the model an assumption that 10% of the time the Demand Curve will clear at the 75% of the reference value, representing the point at which a unit could bid and clear without any further mitigation even if not developed in response to market forces. The assumption of 10% is~~

⁵⁷ <http://www.eia.gov/forecasts/aeo/assumptions/pdf/0554%282012%29.pdf> – pages 94-95

admittedly judgmental as this type of assumption is not subject to empirical verification. [NTD – NERA is open to consideration of other values for this variable and to ideas as to how such a value could be developed from data] We apply this in New York City, the NCZ (the proposed G-J Locality), and the balance of the NYCA (Load Zones A-F), except for Long Island **Regulatory Risk** – The regulatory risk variable was allowed for in the model to recognize that by necessity, the capacity market is affected by regulatory actions and that the impact of these actions may be non-symmetrical. In 2007, NERA recommended a regulatory risk equal to a ten percent probability that the capacity payment would only be 50% of the value it would otherwise be due to non-symmetrical regulatory risk. The factor was not used in NYISO's filing. In 2010, NERA did not include the regulatory risk factor, noting that the markets did not seem to have experienced regulatory risk and seemed to be maturing. Regulatory actions could in theory affect the Demand Curve in both directions. Buyer side mitigation rules are unlikely to be perfect. In theory, such rules could limit economic entry or allow uneconomic entry by virtue of the fact that mitigation determinations, in order to be objective, must be rule based, yet reflective of forecast conditions, and no set of rules can be developed from a perfect forecast. Arguments could be made that regulatory risk is symmetrical in direction albeit not necessarily in magnitude. For example a merchant entrant that was planning to enter based on the view that older plants would retire, may be mitigated by rules that do not consider in the analysis forecasts that such retirements will occur. In this way the buyer side mitigation rules would result in higher capacity prices. In the other direction, an entrant will not be mitigated below 75% of Net Cone even if it has a higher cost. This could result in capacity prices that never rise above 75% of Net Cone. NYISO is working to remedy the first example, by allowing a merchant exemption for buyer side mitigation. NYISO has also indicated that it is open to consider moving the offer floor under the buyer side mitigation rules from 75% of mitigation Net Cone to 100%. While it is likely that regulatory risk will always exist, there do appear to be efforts to address risk when it arises and alleviate the market effect of risk. We have modified the model to allow for the regulatory risk factor to have a sunset date. In this report we use a regulatory risk factor of 10%, which sets capacity prices 10% below that which they would otherwise be and that persists for six years or two resets. After six years, the risk is set at zero, assuming it is symmetrical and that any asymmetries are corrected. The impact of the regulatory risk variable is shown below.

Effect of Regulatory Risk Adjustment on Net Costs in 2014\$ per kW-year

	<u>W/O Regulatory Risk</u>	<u>W/ Regulatory Risk</u>
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	<u>Annual Net Cost</u>	<u>Implied Amortization Period</u>	<u>Annual Net Cost</u>	<u>Implied Amortization Period</u>
<u>LMS100</u>				
<u>LI</u>	<u>110.48</u>	<u>21.5</u>	<u>114.58</u>	<u>20.5</u>
<u>NYC</u>	<u>212.98</u>	<u>16.5</u>	<u>220.90</u>	<u>15.5</u>
<u>G to J</u>	<u>165.51</u>	<u>21.5</u>	<u>171.67</u>	<u>20.5</u>
<u>Capital</u>	<u>157.66</u>	<u>24.5</u>	<u>163.55</u>	<u>22.5</u>
<u>Central</u>	<u>156.01</u>	<u>24.5</u>	<u>161.83</u>	<u>22.5</u>
<u>CCGT</u>				
<u>LI</u>	<u>69.80</u>	<u>21.5</u>	<u>72.35</u>	<u>21.5</u>
<u>NYC</u>	<u>329.42</u>	<u>14.5</u>	<u>341.59</u>	<u>13.5</u>
<u>G to J</u>	<u>159.15</u>	<u>19.5</u>	<u>165.05</u>	<u>18.5</u>
<u>Capital</u>	<u>133.88</u>	<u>24.5</u>	<u>138.87</u>	<u>22.5</u>
<u>Central</u>	<u>138.55</u>	<u>23.5</u>	<u>143.72</u>	<u>22.5</u>

The impacts of considering regulatory risk are on the order of 3% on annual net cost, and the impact on implied amortization period is generally 1 year or less. It appears that NYISO is further along in allowing a merchant exemption for buyer side mitigation than in moving toward a change in the buyer side mitigation rules, which influences the decision to allow for a regulatory risk adjustment for a period of time. We will monitor developments and potentially remove the regulatory risk factor if proposals are advanced that would modify the buyer side mitigation rules or if the merchant exemption is not moving along. ~~While currently only Zone J is subject to buyer side mitigation, the NYISO has proposed buyer side mitigation rules apply to new entry in the NCZ. Buyer side mitigation would impact the NYCA clearing price. For Long Island, we assign a 100% probability to the price being only 75% of the reference level. This is premised on the fact that for Long Island, most entry is not market determined, but is done planned on a long term resource need basis by LIPA and by that fact that due to limited interconnections and relatively high cost local energy resources it has been economic to maintain capacity at a relatively high level. (NTD—NERA is open to consideration of other values for this variable and to ideas as to how such a value could be developed from data. Additionally we are open to using an assumption that LI should be treated similarly to the other locations if stakeholders find that our reasoning on this issue is not right.)~~

Net Energy and Ancillary Services Revenues are input for each technology and location at various installed capacity levels. The energy net revenue functions are described in Section ~~HH~~III.

In developing the recommendation, we use a net energy revenue offset that on average reflects the minimum required installed capacity level for each location plus the capacity of the hypothetical unit. As noted above, we have adjusted net revenues to account for Ancillary Service revenue opportunities based on historical data for similar units provided by NYISO. The model allows for the user to determine net energy revenues over the three year reset period using alternate levels of installed capacity. That functionality remains in the model, but is not used as FERC resolved the assumed excess capacity level by accepting tariff revisions that require that for all years it should be based on the minimum required installed capacity level for each location plus the capacity of the hypothetical peaking plant. Our reserve margin adjustment is designed so that each location has on average a 190 MW capacity excess which reflects the capacity of the LMS 100 plant under ICAP conditions.

Property taxes for NYC may be used with or without tax abatement. The effect is very significant. We model the tax abatement scenario using the May 6, 2011 legislation which provides for 15 years of zero property tax, and full property tax at year 16. This scenario and the no abatement scenario use the current effective rate of 4.63% of plant value. The law grants an abatement as a matter of right to the type of unit designated by NYISO as the hypothetical peaking unit or a unit which has an annual average operation during the preceding year of less than eighteen hours following each start. Hence the LMS 100 qualifies for the abatement, assuming that the hypothetical peaking unit would obtain its building permit by April 1, 2015. ~~While our base case results assume that this is the case, we show a “no abatement” alternative as a sensitivity. Our dispatch analyses indicate that a combined cycle unit would optimally operate significantly more than 18 hours per start and would not qualify for abatement. There are many ways the operating hours for each start could be reduced to qualify for abatement—including at one extreme shutting down for a short interval (e.g., 15 minutes) as the 18 hour point nears and doing a hot start and repeating this every 18 hours and at the other extreme limiting operation to no more than 18 hours per start and allowing the unit to cool down and restart after a full cycle. The first alternative would have very little impact on net energy revenues, while the second would likely have a major impact. However, it would seem risky to assume that the first alternative would lead to a tax abatement, which appears to be a determination made retrospectively on a year by year basis. Additionally, attempts to restrict operation in more meaningful ways could lead to large declines in net energy revenues. For these reasons, we have assumed no tax abatement would be given to the combined cycle unit in the case we develop for~~

~~informational purposes. Stakeholders have been provided access to the model and can examine what the results would be with tax abatement. Additionally stakeholders have been provided with access to the net energy revenue model and data and can examine how various operating strategies may affect net energy revenues. Our dispatch analyses indicate that a combined cycle unit would optimally operate significantly more than 18 hours per start and would not qualify for abatement. We perform a Sensitivity Analysis where the NYC CCGT plant receives abatement. We approximate net energy revenues by a dispatch that does not allow overnight operation to optimize net energy revenues. This drops the average hours per start to a value in the low 20 hours per start. We also reduce AS revenues. Even under this sensitivity, the LMS 100 has a lower net cost in NYC.~~

~~**Deliverability**—The technology specific estimates developed by S&L all include system upgrade and deliverability costs as determined by NYISO. {NTD—the draft report states this as the final values will. These data are not yet available.} We have deleted this section instead of leaving in old text. Gloria had edits to old text and they raised valid points, but we would rather not edit text that we say is~~

~~E.~~ **Analysis of Results**

~~{NTD—As the energy analysis is not yet complete, this section has not been included.}~~

~~**Deliverability**—NYISO’s Deliverability Study did not identify any deliverability costs.~~

~~F.E.~~ **Demand Curve Shape and Slope Recommendations**

The Demand Curves that are recommended for each technology and region have been presented in the Executive Summary. We describe in this section our recommendations for the Demand Curve zero crossing points or slopes. We use the term slope to refer to the zero crossing point. ~~-As discussed in the Executive Summary, based on the FTI Report’s economic analysis and the FTI/NYISO analysis of the relationship between incremental generating capacity and New York electric system reliability, we recommend retaining the shape of the Demand Curves and moving the zero crossing points (slopes) in the direction indicated by the FTI Report. We also, however, considered the factors discussed below.~~

The method that we use to develop the Demand Curves produces curves that contain a consistent slope and reference point that are expected to yield the same present value of revenue to generators as any other consistent combination given the tendency toward not letting the market go short. Hence, if we increase the zero crossing point we would reduce the reference point and vice versa. These consistent combinations also yield the same expected value of payments to generators. Hence, alternate zero crossing points would all have the same expected price impact. As the zero crossing point is moved in towards the origin, the reference price will rise and as the zero crossing point is pushed away from the origin, the reference price will decline. With neither buyer cost nor generator revenue being a deciding factor, the basis for slope selection is narrowed. -This does not, however, present a reason not to move as the FTI Report indicates.

One criterion for slope selection in the past has been market power. As NYISO's market power mitigation rules for NYC are well established, -and the NYISO's monitoring of capacity market activity including offers and offering behavior in other locations, we do not believe that market power is any longer a driving rationale for slope and shape determination. Again, this does not present a reason not to move as the FTI Report indicates.

~~We do remain concerned, however, that moving the zero crossing point towards the origin increases the importance of the assumptions with respect to the average excess capacity level and standard deviation of that level. With a steep slope, if there is an understatement of the average level of excess and standard deviation, the demand curve will be under-compensatory and sufficient capacity may not develop. Similarly if there is an overstatement of the average level of excess, a steep slope will exaggerate the required increase in demand at reference. Steeper slopes increase risk and uncertainty for both the buyer and seller. Steeper slopes can also be counterproductive if a little excess in additions or a decline in growth leads to clearing at prices well below the reference point. At such prices, retaining existing plants may be difficult as the economics of mothballing and retirement could become attractive for older marginal plants. To the extent that such scenarios occur, any decrease in payments that would arise from a steeper slope may well be offset by retirements or mothballing. The same applies to Special Case Resources. Changes in the slope and shape which reduce the capacity price at these excess levels would be expected to lower Special Case Resource participation.~~

Most importantly we look at the rationale underlying the Demand Curve construct. The Demand Curve is designed to induce new capacity when required by supplementing the shortfall in the energy market and providing a reasonably predictable stream of revenue to new generators based on the entry costs of a new peaking unit. The payment is set exactly to that level at the target capacity level and to a linearly higher level at lower capacity values and a linearly lower value at higher capacity levels. As the value of capacity on either side of the target is not linear but exponential, the Demand Curve was clearly not constructed to approximate the value of capacity, but to reduce the volatility of capacity payments and to provide a framework for encouraging investment. Although it may be possible to change the slope and still provide proper investment signals, it would also need to be recognized that steeper slopes increase risk and entry costs.

{NTD—The red highlighted text from the last reset is left in this draft only to show the type of discussion anticipated. It will be updated in the next draft after the net energy revenue analysis is complete. Additionally, we will consider the recommendation in the FTI report.}

The slopes in the current Demand Curves are reasonable as they result in implied amortization periods just ~~over 19, 15 and 15~~ 21.5 years in in NYCA, NYC and LI, 19.5 years in Zones G to J and 14.5 years in NYC, respectively, resulting in a sustainable market system. ~~Note that despite the more gradual slope in NYC and LI, the risk evidenced by the implied amortization period is actually greater due the size of the respective markets.—We~~ By this, we mean one where prices are not unreasonably high. We would hesitate to recommend slopes that yield shorter implied amortization periods. Much like a mortgage payment, the annual cost begins to flatten out at 15 years and by 20 years is in a gradual trajectory toward its lowest point. Hence, slopes that yield amortization periods of 15 to 20 years are as steep as is advisable if the point to develop a reasonable cost of entry and a sustainable market system. ~~We noted above that PJM uses a single assumption of a 20 year amortization period. Hence, we conclude that the current slopes should not be increased by moving the zero crossing point toward the origin. Further, even if the amortization periods were indicating implied amortization periods that equaled or exceeded 30 years and indicated room to adjust the slope, we would not recommend such an adjustment at this time. As we show above excess capacity levels for 2009 are already near the zero crossing point. We would expect that similar levels would apply in the reset period. Adjusting the curve to steepen the slope when it is almost certain to depress revenues would appear opportunistic and would likely undermine confidence in the objectivity of the capacity market. Any significant adjustment to the slope is best~~

done at a time when the immediate impact will be relatively neutral so that it is clear that the adjustment is being made to improve the market not to reach a desired outcome. In summary, we recommend against any adjustments to the slope of the Demand Curve as the implied amortization periods produced by the current slopes are reasonable, and would, even if the desirability of an adjustment was observed, recommend deferring it until such time as the impact would be relatively neutral. The fact that curves developed using the FTI value of excess capacity study (FTI Study) yield reasonable amortization periods is another factor we consider in recommending a move toward zero crossing points recommended in the FTI Report.

The same applies to the shape of the curve. While a kink could be placed in the curve beyond the point where the model recognizes excess and the amortization period unaffected, a kink in the curve which would reduce capacity payments beyond the kink point would clearly be expected to significantly lower capacity revenues during the reset period. This is the case because the average 2009 ROS excess of 9% would likely be well beyond any kink that has a zero crossing point at 12%; the average NYC and LI excesses of 13% and 16%, respectively, would be beyond any kink that has a zero crossing point of 18%. A kink would be nearly certain to lower capacity payments. As past investment was induced without such a kink we view this as opportunistic and likely to add significantly to investment risk. We recommend that the implementation of a kink be considered when the near-term impact would be neutral. Further, we are concerned over the stability of the price signals particularly for Special Case Resources. The impact of a kinked Demand Curve, which could result in sharp changes in capacity clearing prices around the kinked point could result in a non-stable price environment and discourage these resources. While the kink feature remains in the model, we recommend that it be used with caution as the way in which NYISO translate an annual net costs to the Demand Curve reference point with a kink is not known.

We do recognize that in NYC and Long Island the 18% crossing point does mean that at a 0% excess capacity level, customers pay half the net annual cost of a new peaking unit through the Demand Curves. Even at a 12% excess capacity level, customers pay one-third of the net annual cost of a new peaking unit through the Demand Curve. At these excess levels, from a reliability perspective, there is almost no value to Capacity. Hence, there are valid arguments that a steeper Demand Curve slope would lower customer costs and provide stronger signals for older units to retire for fewer MW of new supply entry, and would better align what customers pay for Capacity with the marginal value of Capacity. On the other hand we also recognize that the gradual slope

was intended to eliminate the problems of the vertical Demand Curve and ensure a degree of revenue stability. A kinked Demand Curve that maintains the gradual slope for levels of excess capacity up to, by way of example only, 8%, would serve the purpose of revenue stability and also align customer payments in time of large excesses with the marginal value of Capacity, while providing for better price signals for retirement and demand response program participation. Additionally, as the Demand Curves are based on the net costs of a new peaking unit and not the net cost of a the lowest net cost entrant, and as it appears that the lowest net cost entrant is not a peaking unit, but is a combined cycle unit, a steeper or kinked Demand Curve would reduce the incentive for excess entry by combined cycle units. While there are attractive features of a kinked Demand Curve, weighing all factors is complex, especially when the dynamic effects are difficult to predict. Reducing expected Capacity payments at larger excess levels by steepening the slope after a kink point may appear to reduce customer payments but could have the opposite effect if it reduces entry by new combined cycle units, which would in turn lower energy costs and environmental exposure, and also result in retirements of existing units and lower participation in demand response programs. Hence, it is not clear that a kinked curve would reduce customer payments for energy and Capacity combined. When we consider the uncertainty of the dynamic impacts with the fact that we believe that a change in the slope when there are large excesses would lead to an increased perception of regulatory risk, we do not recommend a change at this time. However, as noted above the kinked Demand Curve does appear to provide a way to achieve both revenue stability and to better reflect the marginal value of Capacity at higher excess levels. We recommend that analysis of the shape and slope issue, and consideration thereof, begin before the initiation of the next Demand Curve reset process. That earlier timing would provide an opportunity to consider the dynamic effects including customer total energy and Capacity payments, and an opportunity if appropriate, to implement the change if approved in the reset process. For example, beginning that analysis five years from the next Demand Curve determination would provide an opportunity so that the result would be knowable with relative certainty at the time of the decision and the decision could be made on its long term merits.

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VI.V. Sensitivity Analyses

NTD—In the last reset this section, which was two pages, focused primarily on the impact of the level of excess assumption and zero crossing point. We intend this year to discuss the zero crossing point impact in our analysis of the shape and slope of the Demand Curve and as FERC approved the tariff revision to set the level of excess assumption at the MW capacity level of the hypothetical unit we will not discuss the impact of alternate levels of excess. We will include a “no abatement” sensitivity for the LMS 100.

NERA examined a variety of sensitivity analyses to demonstrate the impact of alternate assumptions on the Demand Curve results. These cases and impacts on results are described below. While stakeholders have the model and can perform any sensitivity they desire, we have selected some that we believe would be of interest.

A. Zero Crossing Point

Decreases in the zero crossing point increase the slope of the demand curve and increase the clearing price. Increases in the zero crossing point decrease the slope of the demand curve and reduce the clearing price. NERA examined the sensitivity of the annual reference value to several changes in the zero crossing point as we are recommending changes in this area. The cases we examined and results are shown below.

Region	Unit	Zero Crossing Point	Reference Price 2014\$/KW-Year
C - Central	LMS100	112.0%	163.18
C - Central	LMS100	113.5%	161.83
C - Central	LMS100	115.0%	160.83
C - Central	CC	112.0%	145.71
C - Central	CC	113.5%	143.72
C - Central	CC	115.0%	142.24
F - Capital	LMS100	112.0%	164.90
F - Capital	LMS100	113.5%	163.55
F - Capital	LMS100	115.0%	162.54
F - Capital	CC	112.0%	140.80
F - Capital	CC	113.5%	138.87
F - Capital	CC	115.0%	137.45
G - J	LMS100	112.0%	180.14
G - J	LMS100	113.5%	175.18
G - J	LMS100	115.0%	171.67
G - J	CC	112.0%	180.06
G - J	CC	113.5%	171.12

<u>Region</u>	<u>Unit</u>	<u>Zero Crossing Point</u>	<u>Reference Price</u> <u>2014\$/KW-Year</u>
<u>G – J</u>	<u>CC</u>	<u>115.0%</u>	<u>165.05</u>
<u>J - New York City</u>	<u>LMS100</u>	<u>115.0%</u>	<u>226.87</u>
<u>J - New York City</u>	<u>LMS100</u>	<u>116.5%</u>	<u>220.90</u>
<u>J - New York City</u>	<u>LMS100</u>	<u>118.0%</u>	<u>216.45</u>
<u>J - New York City</u>	<u>CC</u>	<u>115.0%</u>	<u>359.40</u>
<u>J - New York City</u>	<u>CC</u>	<u>116.5%</u>	<u>341.59</u>
<u>J - New York City</u>	<u>CC</u>	<u>118.0%</u>	<u>328.66</u>

B. Gas Prices

Econometric estimates of energy revenues have been developed using both historical and futures gas prices. The table below shows these results.

<u>Region</u>	<u>Unit</u>	<u>Zero Crossing Point</u>	<u>Historical Gas</u> <u>Reference Price</u> <u>2014\$/KW-Year</u>	<u>Futures Gas</u> <u>Reference Price</u> <u>2014\$/KW-Year</u>
<u>C – Central</u>	<u>LMS100</u>	<u>113.5%</u>	<u>161.83</u>	<u>163.47</u>
<u>C – Central</u>	<u>CC</u>	<u>113.5%</u>	<u>143.72</u>	<u>157.27</u>
<u>F – Capital</u>	<u>LMS100</u>	<u>113.5%</u>	<u>163.55</u>	<u>168.70</u>
<u>F – Capital</u>	<u>CC</u>	<u>113.5%</u>	<u>138.87</u>	<u>158.48</u>
<u>G – J</u>	<u>LMS100</u>	<u>115.0%</u>	<u>171.67</u>	<u>176.41</u>
<u>G – J</u>	<u>CC</u>	<u>115.0%</u>	<u>165.05</u>	<u>180.56</u>
<u>J - New York City</u>	<u>LMS 100</u>	<u>116.5%</u>	<u>220.90</u>	<u>224.99</u>
<u>J - New York City</u>	<u>CC</u>	<u>116.5%</u>	<u>341.59</u>	<u>358.06</u>
<u>K - Long Island</u>	<u>LMS100</u>	<u>118.0%</u>	<u>114.58</u>	<u>111.59</u>
<u>K - Long Island</u>	<u>CC</u>	<u>118.0%</u>	<u>72.35</u>	<u>79.89</u>

C. NYC Property Tax Abatement

In New York City, a unit may qualify for property tax abatement if it runs no more than 18 hours on average after each start. The base case has no abatement as the unit runs well over 100 hours per start. The sensitivity case assumes tax abatement. To estimate net energy revenues, we do not allow for overnight running to avoid startup costs. The result is operation of roughly twenty hours per start and reduced net energy revenues. Ancillary service revenues are cut in half as the plant will not be able to earn 10 minute spinning revenues if it is not operating at minimum load overnight.

The energy and AS revenue estimates are reasonable approximations and we would make them more precise if the calculations were not illustrative. Even with tax abatement, a combined cycle plant is not the least cost plant in NYC.

<u>Region</u>	<u>Unit</u>	<u>Zero Crossing Point</u>	<u>Reference Price 2014\$/KW-Year</u>
<u>J - New York City</u>	<u>CC</u>	<u>116.5%</u>	<u>341.42</u>
<u>J - New York City with tax abatement</u>	<u>CC</u>	<u>116.5%</u>	<u>259.93</u>

D. Alternate Nodal Location in NYC

In response to comments that the NYC location for the nodal to zonal adjustment should look at higher costs bus, we examined net energy revenues looking at an Astoria 138 KV bus. Our base results and the results for the base case which uses Rainey (Ravenswood 345 KV Bus) are shown below.

<u>Region</u>	<u>Unit</u>	<u>Zero Crossing Point</u>	<u>Reference Price 2014\$/KW-Year</u>
<u>J - New York City</u>	<u>LMS 100</u>	<u>116.5%</u>	<u>220.84</u>
<u>J - New York City Astoria 138 Bus</u>	<u>LMS 100</u>	<u>116.5%</u>	<u>217.74</u>
<u>J - New York City</u>	<u>CC</u>	<u>116.5%</u>	<u>341.42</u>
<u>J - New York City Astoria 138 Bus</u>	<u>CC</u>	<u>116.5%</u>	<u>334.05</u>

E. Rockland County Location for Zone G

As noted in previous sections of the report, for Zones G to J we use the Dutchess County cost characteristics for the plants, the Iroquois Zone 2 gas price and Bowline nodal to zonal factors. To develop a cost estimate that would represent a Rockland County location we use Rockland County cost characteristics for the plants, the TET M-3 gas price and Bowline nodal to zonal factors.

<u>Region</u>	<u>Unit</u>	<u>Zero Crossing Point</u>	<u>Reference Price 2014\$/KW-Year</u>
<u>G - J -</u>	<u>LMS 100</u>	<u>115.0%</u>	<u>171.73</u>
<u>G - J – All Rockland</u>	<u>LMS 100</u>	<u>115.0%</u>	<u>169.54</u>
<u>G - J</u>	<u>CC</u>	<u>115.0%</u>	<u>165.15</u>
<u>G m- J –All Rockland</u>	<u>CC</u>	<u>115.0%</u>	<u>142.93</u>

F. Scale of Plant

Comments have questioned plant scale. Larger plants could potentially have a lower per KW cost, but would result in larger excesses. The lower costs will reduce the Demand Curve, while the larger excess will increase the costs. We performed a sensitivity where the plant size was doubled, doubling the excess MW from approximately 190 MW to 380 MW. We examined this case for a 5% and a 10% reduction in over KW investment costs. The results are shown below.

<u>Region</u>	<u>Unit</u>	<u>Zero Crossing Point</u>	<u>Standard Plant Size – 0% Reduction in Investment Cost Reference Price 2014\$/KW-Year</u>	<u>Double Plant Size – 5% Reduction in Investment Cost 2014\$/KW-Year</u>	<u>Double Plant Size – 10% Reduction in Investment Cost 2014\$/KW-Year</u>
C – Central	LMS100	113.5%	161.83	162.83	153.02
C – Central	CC	113.5%	143.72	151.44	140.88
F – Capital	LMS100	113.5%	163.55	163.53	152.81
F – Capital	CC	113.5%	138.87	144.73	133.58
G – J	LMS100	115.0%	171.67	189.28	176.08
G – J	CC	115.0%	165.05	208.83	192.43
J - New York City	LMS 100	116.5%	220.90	259.98	242.82
J - New York City	CC	116.5%	341.59	482.78	450.09
K - Long Island	LMS100	118.0%	114.58	157.80	138.25
K - Long Island	CC	118.0%	72.35	143.83	109.19

VII.VI. Appendices

A. Appendix 1 – Construction Cost and Unit Operating Cost Details

Appendix 1 provides more detailed information about the capital and operating costs and performance characteristics of the peaking technologies evaluated in this study.

Table A-1 provides information on the assumptions used to estimate the performance characteristics of the Siemens SGT6-5000F(5), GE LMS100, and Wartsila 18V50DF/18V50SG technologies in each Zone⁵⁸. Table A-2 provides information on the capacity and heat rates of each technology by location, as a function of elevation, temperature, and humidity based on the assumptions in Table A-1. Table A-2 also shows data for outage rates, start-up fuel, annual fixed O&M cost, annual site leasing, property taxes and insurance costs, and variable O&M costs.

Tables A-3 through A-5 provide capital cost estimates for each technology by location. Cost breakdown is provided for both EPC and non-EPC costs. The definition of most cost categories is self-evident. Owner's Project Management and Miscellaneous Engineering refer to the cost of preliminary engineering, owner's engineer during construction, and general oversight. Owner's Development Costs refer to the owner's internal costs for all development activities from the initial feasibility studies through start-up. Financing Fees are sometimes built into the interest rate, but here are explicitly broken out.

Table A-6 provides a comparison of LMS100 capital cost estimates in New York City for this study with the published cost estimates of the previous Demand Curve Resets (DCR) in 2007 and 2010.

[Table A-7 shows conventional startup times for each technology for cold, warm and hot starts. Fast startup times are shown for the combined cycle technology.](#)

⁵⁸ Capital and O&M costs were estimated for two locations in Zone G--Dutchess and Rockland Counties. The elevation, temperature and humidity assumptions for Poughkeepsie, in Dutchess County, were used to estimate the capacity and heat rate of each technology in both Dutchess and Rockland Counties.

Table A-1 — Site Assumptions for Capacity and Heat Rate Calculations

Load Zone	Weather Basis	Elev. (Feet)	Season	Ambient Temp. °F	Relative Humidity
C – Central	Syracuse	421	Summer	79.7	67.7
			Winter	17.3	73.7
			Spring-Fall	59.0	60.0
			ICAP	90.0	70.0
F – Capital	Albany	275	Summer	80.7	67.2
			Winter	15.3	70.7
			Spring-Fall	59.0	60.0
			ICAP	90.0	70.0
G - Hudson Valley	Poughkeepsie	165	Summer	82.3	77.7
			Winter	19.3	74.0
			Spring-Fall	59.0	60.0
			ICAP	90.0	70.0
J - New York City	New York City	20	Summer	83.0	64.3
			Winter	28.0	61.7
			Spring-Fall	59.0	60.0
			ICAP	90.0	70.0
K - Long Island	Long Island	16	Summer	80.7	69.3
			Winter	28.0	66.2
			Spring-Fall	59.0	60.0
			ICAP	90.0	70.0

Table A-2— Performance and Operating Cost Characteristics by Technology and Location

	Zone K (LI) 2 x LMS100 PA	Zone J (NYC) 2 x LMS100 PA	Zone G (HV) - Dutchess 2 x LMS100 PA	Zone G (HV) - Rockland 2 x LMS100 PA	Zone F (Alb) 2 x LMS100 PA	Zone C (Syr) 2 x LMS100 PA	Comments
Combustion Turbine Model							
Plant Performance (per Unit)*							
Net Plant Capacity - Summer (MW)	100.01	97.26	97.83	97.83	99.21	99.03	Avg. degraded value; with evaporative
Net Plant Capacity - Winter (MW)	100.06	99.26	100.26	100.26	100.45	100.85	Avg. degraded value; evaporative cooler
Net Plant Capacity - Summer/Winter Avg. (MW)	100.03	98.26	99.05	99.05	99.83	99.94	Avg. degraded value.
Net Plant Capacity - ICAP (MW)	94.70	92.00	94.13	94.13	93.71	93.13	Avg. degraded value; with evaporative
Net Plant Capacity - ICAP (MW)	96.14	93.40	95.56	95.56	95.13	94.54	New and clean value; with evaporative
Net Plant Heat Rate - Summer (Btu/kWh)	9,234	9,313	9,264	9,264	9,232	9,224	Avg. degraded value; with evaporative
Net Plant Heat Rate - Winter (Btu/kWh)	9,086	9,159	9,068	9,068	9,056	9,046	Avg. degraded value; evaporative cooler
Net Plant Heat Rate - Summer/Winter Avg.	9,160	9,236	9,166	9,166	9,144	9,135	Avg. degraded value.
Net Plant Heat Rate - ICAP (Btu/kWh)	9,330	9,424	9,331	9,331	9,332	9,335	Avg. degraded value; with evaporative
Net Plant Heat Rate - ICAP (Btu/kWh)	9,190	9,283	9,191	9,191	9,192	9,195	New and clean value; with evaporative
Equivalent Forced Outage Rate - Demand	2.17%	2.17%	2.17%	2.17%	2.17%	2.17%	Long-term average.
Natural Gas Consumed During Start (mmBtu/start, per Unit)	215	215	215	215	215	215	Cold start for simple cycle. Warm start for combined cycle, thru steam turbine max. load.

	Zone K (LI) 2 x LMS100 PA	Zone J (NYC) 2 x LMS100 PA	Zone G (HV) - Dutchess 2 x LMS100 PA	Zone G (HV) - Rockland 2 x LMS100 PA	Zone F (Alb) 2 x LMS100 PA	Zone C (Syr) 2 x LMS100 PA	Comments
Combustion Turbine Model							
Fixed O&M (\$/year)							
Labor - Routine O&M	1,188,000	1,337,000	1,023,000	1,205,000	908,000	782,000	
Materials and Contract Services - Routine	340,000	340,000	340,000	340,000	340,000	340,000	
Administrative and General	370,000	370,000	370,000	370,000	370,000	370,000	
Subtotal Fixed O&M	1,898,000	2,047,000	1,733,000	1,915,000	1,618,000	1,492,000	
\$/kW-year	10.02	11.13	9.21	10.17	8.63	8.01	Based on net degraded ICAP capacity.
Other Fixed Costs (\$/year)							
Site Leasing Costs	138,000	1,440,000	114,000	114,000	114,000	114,000	
Total Fixed O&M without Insurance and Property Taxes	2,036,000	3,487,000	1,847,000	2,029,000	1,732,000	1,606,000	
\$/kW-year	10.75	18.95	9.81	10.78	9.24	8.62	Based on net degraded ICAP capacity.
Property Taxes (without tax abatement)	5,630,000	14,788,000	5,008,000	5,142,000	4,806,000	4,741,000	Full amount, not accounting for UTEP
Insurance	844,000	958,000	751,000	771,000	721,000	711,000	
Total Fixed O&M with Insurance and Property Taxes	8,510,000	19,233,000	7,606,000	7,942,000	7,259,000	7,058,000	
\$/kW-year	44.93	104.53	40.40	42.19	38.73	37.90	Based on net degraded ICAP capacity.
Variable O&M (\$/MWh)							
Major Maintenance Parts	2.70	2.75	2.73	2.73	2.70	2.70	
Major Maintenance Labor	0.20	0.20	0.17	0.20	0.16	0.14	Labor rates consistent with capital cost
Unscheduled Maintenance	0.86	0.86	0.86	0.86	0.86	0.86	
SCR Catalyst and Ammonia	1.00	1.00	1.00	1.00	1.00	1.00	
CO Oxidation Catalyst	0.40	0.40	0.40	0.40	0.40	0.40	
Other Chemicals and Consumables	0.18	0.18	0.18	0.18	0.18	0.18	
Water	0.08	0.08	0.08	0.08	0.08	0.08	
Total Variable O&M (\$/MWh)	5.42	5.47	5.42	5.45	5.38	5.36	Based on net degraded summer/winter
Variable O&M - Cost per Start:							Excluding natural gas consumed (shown
Major Maintenance Parts	n/a	n/a	n/a	n/a	n/a	n/a	.
Major Maintenance Labor	n/a	n/a	n/a	n/a	n/a	n/a	Labor rates consistent with capital cost
Total (\$/factored start)	n/a	n/a	n/a	n/a	n/a	n/a	Factored starts include representative

	Zone K (LI) 2 x LMS100 PA	Zone J (NYC) 2 x LMS100 PA	Zone G (HV) - Dutchess 2 x LMS100 PA	Zone G (HV) - Rockland 2 x LMS100 PA	Zone F (Alb) 2 x LMS100 PA	Zone C (Syr) 2 x LMS100 PA	Comments
Combustion Turbine Model							
NOx emissions lb/hr per CT or per Engine							
Summer	8.4	8.3	8.3	8.3	8.3	8.3	
Winter	8.3	8.3	8.3	8.3	8.3	8.3	
Spring-Fall	8.5	8.5	8.5	8.5	8.5	8.5	
Average	8.4	8.4	8.4	8.4	8.4	8.4	
ICAP	8.1	7.9	8.0	8.0	8.0	7.9	
CO2 emissions lb/hr per CT or per Engine							
Summer	110,941	108,827	108,871	108,871	110,023	109,727	
Winter	109,260	109,266	109,275	109,275	109,345	109,640	
Spring-Fall	111,759	111,769	112,058	112,058	112,283	112,611	
Average	110,930	110,408	110,565	110,565	110,984	111,147	
ICAP	106,140	104,154	105,514	105,514	105,053	104,431	

	Zone K (LI)	Zone J (NYC)	Zone G (HV) - Dutchess	Zone G (HV) - Rockland	Zone F (Alb)	Zone C (Syr)	Comments
Combustion Turbine Model	1 x 1 x 1 SGT6 PAC5000F(5)	1 x 1 x 1 SGT6 PAC5000F(5)	1 x 1 x 1 SGT6 PAC5000F(5)	1 x 1 x 1 SGT6 PAC5000F(5)	1 x 1 x 1 SGT6 PAC5000F(5)	1 x 1 x 1 SGT6 PAC5000F(5)	
Plant Performance (per Unit)*							
Net Plant Capacity - Summer (MW)	317.50	313.96	310.92	310.92	315.22	314.45	Avg. degraded value; with evaporative
Net Plant Capacity - Winter (MW)	329.72	325.90	328.72	328.72	328.13	328.31	Avg. degraded value; evaporative cooler
Net Plant Capacity - Summer/Winter Avg. (MW)	323.61	319.93	319.82	319.82	321.68	321.38	Avg. degraded value.
Net Plant Capacity - ICAP (MW)	305.97	303.89	303.81	303.81	303.24	301.67	Avg. degraded value; with evaporative
Net Plant Capacity - ICAP (MW)	315.43	313.29	313.21	313.21	312.61	311.00	New and clean value; with evaporative
Net Plant Heat Rate - Summer (Btu/kWh)	7,177	7,237	7,217	7,217	7,172	7,168	Avg. degraded value; with evaporative
Net Plant Heat Rate - Winter (Btu/kWh)	7,022	7,104	7,028	7,028	7,037	7,033	Avg. degraded value; evaporative cooler
Net Plant Heat Rate - Summer/Winter Avg.	7,100	7,171	7,123	7,123	7,105	7,101	Avg. degraded value.
Net Plant Heat Rate - ICAP (Btu/kWh)	7,242	7,291	7,253	7,253	7,243	7,240	Avg. degraded value; with evaporative
Net Plant Heat Rate - ICAP (Btu/kWh)	7,025	7,073	7,036	7,036	7,025	7,023	New and clean value; with evaporative
Equivalent Forced Outage Rate - Demand	2.04%	2.04%	2.04%	2.04%	2.04%	2.04%	Long-term average.
Natural Gas Consumed During Start (mmBtu/start, per Unit)	1,688	1,688	1,688	1,688	1,688	1,688	Cold start for simple cycle. Warm start for combined cycle, thru steam turbine max. load.

	Zone K (LI) 1 x 1 x 1 SGT6- PAC5000F(5)	Zone J (NYC) 1 x 1 x 1 SGT6- PAC5000F(5)	Zone G (HV) - Dutchess 1 x 1 x 1 SGT6- PAC5000F(5)	Zone G (HV) - Rockland 1 x 1 x 1 SGT6- PAC5000F(5)	Zone F (Alb) 1 x 1 x 1 SGT6- PAC5000F(5)	Zone C (Syr) 1 x 1 x 1 SGT6- PAC5000F(5)	Comments
Combustion Turbine Model							
Fixed O&M (\$/year)							
Labor - Routine O&M	3,416,000	3,416,000	2,942,000	3,464,000	2,784,000	2,397,000	
Materials and Contract Services - Routine	3,140,000	3,140,000	3,140,000	3,140,000	3,140,000	3,140,000	
Administrative and General	620,000	620,000	620,000	620,000	620,000	620,000	
Subtotal Fixed O&M	7,176,000	7,176,000	6,702,000	7,224,000	6,544,000	6,157,000	
\$/kW-year	23.45	23.61	22.06	23.78	21.58	20.41	Based on net degraded ICAP capacity.
Other Fixed Costs (\$/year)							
Site Leasing Costs	460,000	4,800,000	380,000	380,000	380,000	380,000	
Total Fixed O&M without Insurance and Property Taxes	7,636,000	11,976,000	7,082,000	7,604,000	6,924,000	6,537,000	
\$/kW-year	24.96	39.41	23.31	25.03	22.83	21.67	Based on net degraded ICAP capacity.
Property Taxes (without tax abatement)	10,390,000	26,768,000	8,706,000	9,062,000	8,061,000	7,860,000	Full amount, not accounting for UTEP
Insurance	1,559,000	1,735,000	1,306,000	1,359,000	1,209,000	1,179,000	
Total Fixed O&M with Insurance and Property Taxes	19,585,000	40,479,000	17,094,000	18,025,000	16,194,000	15,576,000	
\$/kW-year	64.01	133.20	56.26	59.33	53.40	51.63	Based on net degraded ICAP capacity.
Variable O&M (\$/MWh)							
Major Maintenance Parts	0.24	0.25	0.25	0.25	0.25	0.25	
Major Maintenance Labor	0.06	0.07	0.06	0.07	0.05	0.05	Labor rates consistent with capital cost
Unscheduled Maintenance	0.26	0.26	0.26	0.26	0.26	0.26	
SCR Catalyst and Ammonia	0.15	0.15	0.15	0.15	0.15	0.15	
CO Oxidation Catalyst	0.05	0.05	0.05	0.05	0.05	0.05	
Other Chemicals and Consumables	0.18	0.18	0.18	0.18	0.18	0.18	
Water	0.09	0.09	0.09	0.09	0.09	0.09	
Total Variable O&M (\$/MWh)	1.04	1.04	1.03	1.04	1.03	1.02	Based on net degraded summer/winter
Variable O&M - Cost per Start:							Excluding natural gas consumed (shown
Major Maintenance Parts	8,795	8,795	8,795	8,795	8,795	8,795	.
Major Maintenance Labor	466	466	402	473	380	327	Labor rates consistent with capital cost
Total (\$/factored start)	9,262	9,262	9,197	9,268	9,176	9,123	Factored starts include representative

	Zone K (LI)	Zone J (NYC)	Zone G (HV) - Dutchess	Zone G (HV) - Rockland	Zone F (Alb)	Zone C (Syr)	Comments
Combustion Turbine Model	1 x 1 x 1 SGT6 PAC5000F(5)	1 x 1 x 1 SGT6 PAC5000F(5)	1 x 1 x 1 SGT6 PAC5000F(5)	1 x 1 x 1 SGT6 PAC5000F(5)	1 x 1 x 1 SGT6 PAC5000F(5)	1 x 1 x 1 SGT6 PAC5000F(5)	
NOx emissions lb/hr per CT or per Engine							
Summer	16.6	16.5	16.4	16.4	16.4	16.4	
Winter	16.5	16.5	16.6	16.6	16.5	16.6	
Spring-Fall	17.2	17.2	17.1	17.1	17.1	17.0	
Average	16.9	16.9	16.8	16.8	16.8	16.7	
ICAP	16.2	16.2	16.1	16.1	16.0	15.9	
CO2 emissions lb/hr per CT or per Engine							
Summer	264,756	264,125	260,891	260,891	262,678	261,777	
Winter	262,124	262,182	266,312	266,312	265,315	266,131	
Spring-Fall	273,998	273,998	272,506	272,506	271,531	270,039	
Average	268,719	268,576	268,054	268,054	267,764	266,996	
ICAP	258,032	258,032	256,583	256,583	255,657	254,208	

	Zone K (LI)	Zone J (NYC)	Zone G (HV) - Dutchess	Zone G (HV) - Rockland	Zone F (Alb)	Zone C (Syr)	Comments
Combustion Turbine Model	18V50	18V50	18V50	18V50	18V50	18V50	
Plant Performance (per Unit)*							
Net Plant Capacity - Summer (MW)	16.51	16.57	16.06	16.06	16.62	17.53	Avg. degraded value; with evaporative
Net Plant Capacity - Winter (MW)	16.62	16.62	16.62	16.62	16.62	18.26	Avg. degraded value; evaporative cooler
Net Plant Capacity - Summer/Winter Avg. (MW)	16.56	16.59	16.34	16.34	16.62	17.89	Avg. degraded value.
Net Plant Capacity - ICAP (MW)	15.69	15.69	15.69	15.69	15.69	16.50	Avg. degraded value; with evaporative
Net Plant Capacity - ICAP (MW)	15.77	15.77	15.77	15.77	15.77	16.58	New and clean value; with evaporative
Net Plant Heat Rate - Summer (Btu/kWh)	8,512	8,512	8,517	8,517	8,512	8,468	Avg. degraded value; with evaporative
Net Plant Heat Rate - Winter (Btu/kWh)	8,512	8,512	8,512	8,512	8,512	8,412	Avg. degraded value; evaporative cooler
Net Plant Heat Rate - Summer/Winter Avg.	8,512	8,512	8,515	8,515	8,512	8,440	Avg. degraded value.
Net Plant Heat Rate - ICAP (Btu/kWh)	8,525	8,525	8,525	8,525	8,525	8,552	Avg. degraded value; with evaporative
Net Plant Heat Rate - ICAP (Btu/kWh)	8,483	8,483	8,483	8,483	8,483	8,509	New and clean value; with evaporative
Equivalent Forced Outage Rate - Demand	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	Long-term average.
Natural Gas Consumed During Start (mmBtu/start, per Unit)	30	30	30	30	30	30	Cold start for simple cycle. Warm start for combined cycle, thru steam turbine max. load.

	Zone K (LI)	Zone J (NYC)	Zone G (HV) - Dutchess	Zone G (HV) - Rockland	Zone F (Alb)	Zone C (Syr)	Comments
Combustion Turbine Model	18V50	18V50	18V50	18V50	18V50	18V50	
Fixed O&M (\$/year)							
Labor - Routine O&M	1,782,000	1,782,000	1,535,000	1,807,000	1,453,000	1,250,000	
Materials and Contract Services - Routine	1,050,000	1,050,000	1,050,000	1,050,000	1,050,000	1,050,000	
Administrative and General	400,000	400,000	400,000	400,000	400,000	400,000	
Subtotal Fixed O&M	3,232,000	3,232,000	2,985,000	3,257,000	2,903,000	2,700,000	
\$/kW-year	17.16	17.16	15.85	17.30	15.42	13.64	Based on net degraded ICAP capacity.
Other Fixed Costs (\$/year)							
Site Leasing Costs	230,000	2,400,000	190,000	190,000	190,000	190,000	
Total Fixed O&M without Insurance and Property Taxes	3,462,000	5,632,000	3,175,000	3,447,000	3,093,000	2,890,000	
\$/kW-year	18.39	29.91	16.86	18.31	16.43	14.60	Based on net degraded ICAP capacity.
Property Taxes (without tax abatement)	8,696,000	22,058,000	7,592,000	7,804,000	7,205,000	7,107,000	Full amount, not accounting for UTEP
Insurance	1,304,000	1,429,000	1,139,000	1,171,000	1,081,000	1,066,000	
Total Fixed O&M with Insurance and Property Taxes	13,462,000	29,119,000	11,906,000	12,422,000	11,379,000	11,063,000	
\$/kW-year	71.49	154.64	63.23	65.97	60.43	55.89	Based on net degraded ICAP capacity.
Variable O&M (\$/MWh)							
Major Maintenance Parts	5.30	5.30	5.30	5.30	5.30	5.30	
Major Maintenance Labor	0.34	0.34	0.34	0.34	0.34	0.34	Labor rates consistent with capital cost
Unscheduled Maintenance	0.34	0.34	0.34	0.34	0.34	0.34	
SCR Catalyst and Ammonia	1.00	1.00	1.00	1.00	1.00	1.00	
CO Oxidation Catalyst	0.30	0.30	0.30	0.30	0.30	0.30	
Other Chemicals and Consumables	0.18	0.18	0.18	0.18	0.18	0.18	
Water	0.08	0.08	0.08	0.08	0.08	0.07	
Total Variable O&M (\$/MWh)	10.98	10.98	10.98	10.98	10.98	10.97	Based on net degraded summer/winter
Variable O&M - Cost per Start:							Excluding natural gas consumed (shown
Major Maintenance Parts	n/a	n/a	n/a	n/a	n/a	n/a	.
Major Maintenance Labor	n/a	n/a	n/a	n/a	n/a	n/a	Labor rates consistent with capital cost
Total (\$/factored start)	n/a	n/a	n/a	n/a	n/a	n/a	Factored starts include representative

	Zone K (LI)	Zone J (NYC)	Zone G (HV) - Dutchess	Zone G (HV) - Rockland	Zone F (Alb)	Zone C (Syr)	Comments
Combustion Turbine Model	18V50	18V50	18V50	18V50	18V50	18V50	
NOx emissions lb/hr per CT or per Engine							
Summer	2.9	3.0	2.8	2.8	2.9	2.6	
Winter	2.9	2.9	2.9	2.9	2.9	2.7	
Spring-Fall	2.9	2.9	2.9	2.9	2.9	2.7	
Average	2.9	2.9	2.9	2.9	2.9	2.7	
ICAP	2.8	2.8	2.8	2.8	2.8	2.5	
CO2 emissions lb/hr per CT or per Engine							
Summer	15,788	16,496	15,562	15,562	15,859	17,311	
Winter	15,788	15,788	15,788	15,788	15,788	17,799	
Spring-Fall	15,788	15,788	15,788	15,788	15,788	17,799	
Average	15,788	15,965	15,732	15,732	15,806	17,677	
ICAP	15,357	15,357	15,357	15,357	15,357	16,553	

	Zone K (LI)	Zone J (NYC)	Zone G (HV) - Dutchess	Zone G (HV) - Rockland	Zone F (Alb)	Zone C (Syr)	Comments
Combustion Turbine Model	2 x LMS100 PA	2 x LMS100 PA	2 x LMS100 PA	2 x LMS100 PA	2 x LMS100 PA	2 x LMS100 PA	
Plant Performance (per Unit)*							
Net Plant Capacity - Summer (MW)	99.00	97.26	96.50	96.50	99.21	99.03	Avg. degraded value; with evaporative cooling.
Net Plant Capacity - Winter (MW)	100.06	99.26	100.26	100.26	100.45	100.85	Avg. degraded value; evaporative cooler off.
Net Plant Capacity - Summer/Winter Avg. (MW)	99.53	98.26	98.38	98.38	99.83	99.94	Avg. degraded value.
Net Plant Capacity - ICAP (MW)	92.76	92.00	92.20	92.20	91.80	93.13	Avg. degraded value; with evaporative cooling.
Net Plant Capacity - ICAP (MW)	94.17	93.40	93.61	93.61	93.20	94.54	New and clean value; with evaporative cooling.
Net Plant Heat Rate - Summer (Btu/kWh)	9,227	9,313	9,271	9,271	9,223	9,224	Avg. degraded value; with evaporative cooling.
Net Plant Heat Rate - Winter (Btu/kWh)	9,086	9,159	9,068	9,068	9,056	9,046	Avg. degraded value; evaporative cooler off.
Net Plant Heat Rate - Summer/Winter Avg. (Btu/kWh)	9,157	9,236	9,170	9,170	9,140	9,135	Avg. degraded value.
Net Plant Heat Rate - ICAP (Btu/kWh)	9,348	9,424	9,351	9,351	9,352	9,335	Avg. degraded value; with evaporative cooling.
Net Plant Heat Rate - ICAP (Btu/kWh)	9,208	9,283	9,210	9,210	9,211	9,195	New and clean value; with evaporative cooling.
Equivalent Forced Outage Rate - Demand Based (EFORd)	2.17%	2.17%	2.17%	2.17%	2.17%	2.17%	Long-term average.
Natural Gas Consumed During Start (mmBtu/start, per Unit)	215	215	215	215	215	215	Cold start for simple cycle. Warm start for combined cycle, thru steam turbine max. load.
NOx emissions lb/hr per CT or per Engine							
Summer	8.3	8.3	8.2	8.2	8.3	8.3	
Winter	8.3	8.3	8.3	8.3	8.3	8.3	
Spring-Fall	8.5	8.5	8.5	8.5	8.5	8.5	
Average	8.4	8.4	8.4	8.4	8.4	8.4	
ICAP	7.9	7.9	7.9	7.9	7.8	7.9	
CO2 emissions lb/hr per CT or per Engine							
Summer	109,745	108,827	107,476	107,476	108,809	109,727	
Winter	109,260	109,266	109,275	109,275	109,345	109,640	
Spring-Fall	111,759	111,769	112,058	112,058	112,283	112,611	
Average	110,631	110,408	110,217	110,217	110,680	111,147	
ICAP	104,170	104,154	103,565	103,565	103,124	104,431	
CO2 emissions lb/MW-hr (gross) per CT or per Engine							
Summer	1,071	1,072	1,076	1,076	1,070	1,070	
Winter	1,055	1,055	1,053	1,053	1,052	1,050	
Spring-Fall	1,060	1,060	1,059	1,059	1,058	1,057	
Average	1,062	1,062	1,062	1,062	1,060	1,059	
ICAP	1,085	1,085	1,085	1,085	1,085	1,083	

	Zone K (LI)	Zone J (NYC)	Zone G (HV) - Dutchess	Zone G (HV) - Rockland	Zone F (Alb)	Zone C (Syr)	Comments
Combustion Turbine Model	2 x LMS100 PA	2 x LMS100 PA	2 x LMS100 PA	2 x LMS100 PA	2 x LMS100 PA	2 x LMS100 PA	
Fixed O&M (\$/year)							
Labor - Routine O&M	1,434,000	1,664,000	1,234,000	1,259,000	882,000	816,000	
Materials and Contract Services - Routine	362,000	367,000	340,000	343,000	308,000	300,000	
Administrative and General	394,000	399,000	370,000	373,000	335,000	326,000	
Subtotal Fixed O&M	2,190,000	2,430,000	1,944,000	1,975,000	1,525,000	1,442,000	
\$/kW-year	11.80	13.21	10.54	10.71	8.31	7.74	Based on net degraded ICAP capacity.
Other Fixed Costs (\$/year)							
Site Leasing Costs	138,000	1,440,000	114,000	114,000	114,000	114,000	
Total Fixed O&M without Insurance and Property Taxes	2,328,000	3,870,000	2,058,000	2,089,000	1,639,000	1,556,000	
\$/kW-year	12.55	21.03	11.16	11.33	8.93	8.35	Based on net degraded ICAP capacity.
Property Taxes (without tax abatement)	6,107,000	15,686,000	5,723,000	5,870,000	5,305,000	5,005,000	Full amount, not accounting for UTEP
Insurance	916,000	1,016,000	858,000	880,000	796,000	751,000	
Total Fixed O&M with Insurance and Property Taxes	9,351,000	20,572,000	8,639,000	8,839,000	7,740,000	7,312,000	
\$/kW-year	50.41	111.81	46.85	47.93	42.16	39.26	Based on net degraded ICAP capacity.
Variable O&M (\$/MWh)							
Major Maintenance Parts	2.71	2.75	2.74	2.74	2.70	2.70	
Major Maintenance Labor	0.24	0.25	0.21	0.22	0.16	0.15	Labor rates consistent with capital cost estimates.
Unscheduled Maintenance	0.86	0.86	0.86	0.86	0.86	0.86	
SCR Catalyst and Ammonia	1.00	1.00	1.00	1.00	1.00	1.00	
CO Oxidation Catalyst	0.40	0.40	0.40	0.40	0.40	0.40	
Other Chemicals and Consumables	0.18	0.18	0.18	0.18	0.18	0.18	
Water	0.08	0.08	0.08	0.08	0.08	0.08	
Total Variable O&M (\$/MWh)	5.47	5.52	5.47	5.48	5.38	5.36	Based on net degraded summer/winter avg. capacity.
Variable O&M - Cost per Start:							Excluding natural gas consumed (shown above).
Major Maintenance Parts	n/a	n/a	n/a	n/a	n/a	n/a	
Major Maintenance Labor	n/a	n/a	n/a	n/a	n/a	n/a	Labor rates consistent with capital cost estimates.
Total (\$/factored start)	n/a	n/a	n/a	n/a	n/a	n/a	Factored starts include representative weighting factors for peaking operation.
* For combined cycle cases, value shown is for entire plant.							

	Zone K (LI) 1 x 1 x 1	Zone J (NYC) 1 x 1 x 1	Zone G (HV) - Dutchess 1 x 1 x 1	Zone G (HV) - Rockland 1 x 1 x 1	Zone F (Alb) 1 x 1 x 1	Zone C (Syr) 1 x 1 x 1	Comments
Combustion Turbine Model	SGT6-5000F(5)	SGT6-5000F(5)	SGT6-5000F(5)	SGT6-5000F(5)	SGT6-5000F(5)	SGT6-5000F(5)	
Plant Performance (per Unit)*							
Net Plant Capacity - Summer (MW)	317.50	313.96	310.92	310.92	315.22	314.45	Avg. degraded value; with evaporative
Net Plant Capacity - Winter (MW)	329.72	325.90	328.72	328.72	328.13	328.31	Avg. degraded value; evaporative cooler
Net Plant Capacity - Summer/Winter Avg. (MW)	323.61	319.93	319.82	319.82	321.68	321.38	Avg. degraded value.
Net Plant Capacity - ICAP (MW)	305.97	303.89	303.81	303.81	303.24	301.67	Avg. degraded value; with evaporative
Net Plant Capacity - ICAP (MW)	315.43	313.29	313.21	313.21	312.61	311.00	New and clean value; with evaporative
Net Plant Heat Rate - Summer (Btu/kWh)	7,177	7,237	7,217	7,217	7,172	7,168	Avg. degraded value; with evaporative
Net Plant Heat Rate - Winter (Btu/kWh)	7,022	7,104	7,028	7,028	7,037	7,033	Avg. degraded value; evaporative cooler
Net Plant Heat Rate - Summer/Winter Avg. (Btu/kWh)	7,100	7,171	7,123	7,123	7,105	7,101	Avg. degraded value.
Net Plant Heat Rate - ICAP (Btu/kWh)	7,242	7,291	7,253	7,253	7,243	7,240	Avg. degraded value; with evaporative
Net Plant Heat Rate - ICAP (Btu/kWh)	7,025	7,073	7,036	7,036	7,025	7,023	New and clean value; with evaporative
Equivalent Forced Outage Rate - Demand Based	2.04%	2.04%	2.04%	2.04%	2.04%	2.04%	Long-term average.
Natural Gas Consumed During Start (mmBtu/start, per Unit)	1,688	1,688	1,688	1,688	1,688	1,688	Cold start for simple cycle. Warm start for combined cycle, thru steam turbine
NOx emissions lb/hr per CT or per Engine							
Summer	16.6	16.5	16.4	16.4	16.4	16.4	
Winter	16.5	16.5	16.6	16.6	16.5	16.6	
Spring-Fall	17.2	17.2	17.1	17.1	17.1	17.0	
Average	16.9	16.9	16.8	16.8	16.8	16.7	
ICAP	16.2	16.2	16.1	16.1	16.0	15.9	
CO2 emissions lb/hr per CT or per Engine							
Summer	264,756	264,125	260,891	260,891	262,678	261,777	
Winter	262,124	262,182	266,312	266,312	265,315	266,131	
Spring-Fall	273,998	273,998	272,506	272,506	271,531	270,039	
Average	268,719	268,576	268,054	268,054	267,764	266,996	
ICAP	258,032	258,032	256,583	256,583	255,657	254,208	
CO2 emissions lb/MW-hr (gross) per CT or per Engine							
Summer	790	792	795	795	790	789	
Winter	754	762	768	768	767	769	
Spring-Fall	778	783	780	780	778	778	
Average	775	780	781	781	778	779	
ICAP	799	799	800	800	799	799	

	Zone K (LI) 1 x 1 x 1	Zone J (NYC) 1 x 1 x 1	Zone G (HV) - Dutchess 1 x 1 x 1	Zone G (HV) - Rockland 1 x 1 x 1	Zone F (Alb) 1 x 1 x 1	Zone C (Syr) 1 x 1 x 1	Comments
Combustion Turbine Model	SGT6-5000F(5)	SGT6-5000F(5)	SGT6-5000F(5)	SGT6-5000F(5)	SGT6-5000F(5)	SGT6-5000F(5)	
Fixed O&M (\$/year)							
Labor - Routine O&M	4,124,000	4,252,000	3,547,000	3,619,000	2,703,000	2,503,000	
Materials and Contract Services - Routine	3,344,000	3,390,000	3,140,000	3,165,000	2,841,000	2,770,000	
Administrative and General	660,000	669,000	620,000	625,000	561,000	547,000	
Subtotal Fixed O&M	8,128,000	8,311,000	7,307,000	7,409,000	6,105,000	5,820,000	
\$/kW-year	26.56	27.35	24.05	24.39	20.13	19.29	Based on net degraded ICAP capacity.
Other Fixed Costs (\$/year)							
Site Leasing Costs	460,000	3,600,000	380,000	380,000	380,000	380,000	
Total Fixed O&M without Insurance and Property Taxes	8,588,000	11,911,000	7,687,000	7,789,000	6,485,000	6,200,000	
\$/kW-year	28.07	39.19	25.30	25.64	21.39	20.55	Based on net degraded ICAP capacity.
Property Taxes (without tax abatement)	10,866,000	28,038,000	9,433,000	9,802,000	8,604,000	8,093,000	Full amount, not accounting for UTEP
Insurance	1,630,000	1,817,000	1,415,000	1,470,000	1,291,000	1,214,000	
Total Fixed O&M with Insurance and Property Taxes	21,084,000	41,766,000	18,535,000	19,061,000	16,380,000	15,507,000	
\$/kW-year	68.91	137.44	61.01	62.74	54.02	51.40	Based on net degraded ICAP capacity.
Variable O&M (\$/MWh)							
Major Maintenance Parts	0.24	0.25	0.25	0.25	0.25	0.25	
Major Maintenance Labor	0.08	0.08	0.07	0.07	0.05	0.05	Labor rates consistent with capital cost
Unscheduled Maintenance	0.26	0.26	0.26	0.26	0.26	0.26	
SCR Catalyst and Ammonia	0.15	0.15	0.15	0.15	0.15	0.15	
CO Oxidation Catalyst	0.05	0.05	0.05	0.05	0.05	0.05	
Other Chemicals and Consumables	0.18	0.18	0.18	0.18	0.18	0.18	
Water	0.09	0.09	0.09	0.09	0.09	0.09	
Total Variable O&M (\$/MWh)	1.05	1.06	1.05	1.05	1.03	1.02	Based on net degraded summer/winter
Variable O&M - Cost per Start:							Excluding natural gas consumed (shown
Major Maintenance Parts	8,795	8,795	8,795	8,795	8,795	8,795	
Major Maintenance Labor	563	580	484	494	369	342	Labor rates consistent with capital cost
Total (\$/factored start)	9,358	9,376	9,280	9,290	9,164	9,137	Factored starts include representative

	Zone K (LI)	Zone J (NYC)	Zone G (HV) - Dutchess	Zone G (HV) - Rockland	Zone F (Alb)	Zone C (Syr)	Comments
Combustion Turbine Model	18V50	18V50	18V50	18V50	18V50	18V50	
Plant Performance (per Unit)*							
Net Plant Capacity - Summer (MW)	16.51	16.57	16.06	16.06	16.62	17.53	Avg. degraded value; with evaporative cooling.
Net Plant Capacity - Winter (MW)	16.62	16.62	16.62	16.62	16.62	18.26	Avg. degraded value; evaporative cooler off.
Net Plant Capacity - Summer/Winter Avg. (MW)	16.56	16.59	16.34	16.34	16.62	17.89	Avg. degraded value.
Net Plant Capacity - ICAP (MW)	15.69	15.69	15.69	15.69	15.69	16.50	Avg. degraded value; with evaporative cooling.
Net Plant Capacity - ICAP (MW)	15.77	15.77	15.77	15.77	15.77	16.58	New and clean value; with evaporative cooling.
Net Plant Heat Rate - Summer (Btu/kWh)	8,512	8,512	8,517	8,517	8,512	8,468	Avg. degraded value; with evaporative cooling.
Net Plant Heat Rate - Winter (Btu/kWh)	8,512	8,512	8,512	8,512	8,512	8,412	Avg. degraded value; evaporative cooler off.
Net Plant Heat Rate - Summer/Winter Avg. (Btu/kWh)	8,512	8,512	8,515	8,515	8,512	8,440	Avg. degraded value.
Net Plant Heat Rate - ICAP (Btu/kWh)	8,525	8,525	8,525	8,525	8,525	8,552	Avg. degraded value; with evaporative cooling.
Net Plant Heat Rate - ICAP (Btu/kWh)	8,483	8,483	8,483	8,483	8,483	8,509	New and clean value; with evaporative cooling.
Equivalent Forced Outage Rate - Demand Based (EFORd)	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	Long-term average.
Natural Gas Consumed During Start (mmBtu/start, per Unit)	30	30	30	30	30	30	Cold start for simple cycle. Warm start for combined cycle, thru steam turbine max. load.
NOx emissions lb/hr per CT or per Engine							
Summer	2.9	3.0	2.8	2.8	2.9	2.6	
Winter	2.9	2.9	2.9	2.9	2.9	2.7	
Spring-Fall	2.9	2.9	2.9	2.9	2.9	2.7	
Average	2.9	2.9	2.9	2.9	2.9	2.7	
ICAP	2.8	2.8	2.8	2.8	2.8	2.5	
CO2 emissions lb/hr per CT or per Engine							
Summer	15,788	16,496	15,562	15,562	15,859	17,311	
Winter	15,788	15,788	15,788	15,788	15,788	17,799	
Spring-Fall	15,788	15,788	15,788	15,788	15,788	17,799	
Average	15,788	15,965	15,732	15,732	15,806	17,677	
ICAP	15,357	15,357	15,357	15,357	15,357	16,553	
CO2 emissions lb/MW-hr (gross) per CT or per Engine							
Summer	931	969	943	943	929	961	
Winter	925	925	925	925	925	949	
Spring-Fall	925	925	925	925	925	949	
Average	926	936	929	929	926	952	
ICAP	952	952	952	952	952	977	

	Zone K (LI)	Zone J (NYC)	Zone G (HV) - Dutchess	Zone G (HV) - Rockland	Zone F (Alb)	Zone C (Syr)	Comments
Combustion Turbine Model	18V50	18V50	18V50	18V50	18V50	18V50	
Fixed O&M (\$/year)							
Labor - Routine O&M	2,152,000	2,218,000	1,851,000	1,888,000	1,410,000	1,306,000	
Materials and Contract Services - Routine	1,118,000	1,133,000	1,050,000	1,058,000	950,000	926,000	
Administrative and General	426,000	432,000	400,000	403,000	362,000	353,000	
Subtotal Fixed O&M	3,696,000	3,783,000	3,301,000	3,349,000	2,722,000	2,585,000	
\$/kW-year	19.63	20.09	17.53	17.79	14.46	13.06	Based on net degraded ICAP capacity.
Other Fixed Costs (\$/year)							
Site Leasing Costs	230,000	2,400,000	190,000	190,000	190,000	190,000	
Total Fixed O&M without Insurance and Property Taxes	3,926,000	6,183,000	3,491,000	3,539,000	2,912,000	2,775,000	
\$/kW-year	20.85	32.84	18.54	18.79	15.46	14.02	Based on net degraded ICAP capacity.
Property Taxes (without tax abatement)	8,959,000	23,095,000	8,117,000	8,333,000	7,428,000	7,330,000	Full amount, not accounting for UTEP
Insurance	1,344,000	1,497,000	1,218,000	1,250,000	1,114,000	1,099,000	
Total Fixed O&M with Insurance and Property Taxes	14,229,000	30,775,000	12,826,000	13,122,000	11,454,000	11,204,000	
\$/kW-year	75.56	163.43	68.11	69.69	60.83	56.60	Based on net degraded ICAP capacity.
Variable O&M (\$/MWh)							
Major Maintenance Parts	5.30	5.30	5.30	5.30	5.30	5.30	
Major Maintenance Labor	0.40	0.41	0.34	0.35	0.26	0.24	Labor rates consistent with capital cost estimates.
Unscheduled Maintenance	0.34	0.34	0.34	0.34	0.34	0.34	
SCR Catalyst and Ammonia	1.00	1.00	1.00	1.00	1.00	1.00	
CO Oxidation Catalyst	0.30	0.30	0.30	0.30	0.30	0.30	
Other Chemicals and Consumables	0.18	0.18	0.18	0.18	0.18	0.18	
Water	0.08	0.08	0.08	0.08	0.08	0.07	
Total Variable O&M (\$/MWh)	11.18	11.22	10.98	11.00	10.69	10.61	Based on net degraded summer/winter avg. capacity.
Variable O&M - Cost per Start:							Excluding natural gas consumed (shown above).
Major Maintenance Parts	n/a	n/a	n/a	n/a	n/a	n/a	
Major Maintenance Labor	n/a	n/a	n/a	n/a	n/a	n/a	Labor rates consistent with capital cost estimates.
Total (\$/factored start)	n/a	n/a	n/a	n/a	n/a	n/a	Factored starts include representative weighting factors for peaking operation.

Table A-3 — Capital Cost Estimates for Simple Cycle Aeroderivative - (2013 \$)

	LMS100 PA - Overnight Capital Cost - 2013\$s					
	K - Long Island	J - NYC	G - Hudson Valley (Dutchess)	G2 - Hudson Valley (Rockland)	F - Capital	C - Central
EPC Cost Components						
Equipment						
Equipment	107,312,000	117,879,000	107,312,000	107,312,000	107,312,000	107,312,000
Spare Parts	1,126,000	1,126,000	1,126,000	1,126,000	1,126,000	1,126,000
Subtotal	108,438,000	119,005,000	108,438,000	108,438,000	108,438,000	108,438,000
Construction						
Construction Labor & Materials	81,420,000	95,379,000	61,298,000	65,849,000	54,517,000	52,397,000
Plant Switchyard	5,468,000	7,346,000	4,619,000	4,771,000	4,285,000	4,193,000
Electrical Interconnection & Delivery	0	0	0	0	0	0
Gas Interconnect & Reinforcement	5,395,000	6,347,000	5,395,000	5,395,000	5,395,000	5,395,000
Site Prep	3,779,000	6,381,000	3,064,000	3,204,000	2,846,000	2,700,000
Engineering & Design	10,716,000	12,171,000	9,542,000	9,804,000	9,145,000	9,018,000
Construction Mgmt. / Field Engr.	2,679,000	3,043,000	2,386,000	2,451,000	2,286,000	2,254,000
Subtotal	109,457,000	130,667,000	86,304,000	91,474,000	78,474,000	75,957,000
Startup & Testing						
Startup & Training	1,786,000	2,028,000	1,590,000	1,634,000	1,524,000	1,503,000
Testing	-	-	-	-	-	-
Subtotal	1,786,000	2,028,000	1,590,000	1,634,000	1,524,000	1,503,000
Contingency	21,316,000	24,210,000	18,981,000	19,503,000	18,192,000	17,938,000
Subtotal - EPC Costs	240,997,000	275,910,000	215,313,000	221,049,000	206,628,000	203,836,000
EPC Costs for Single Fuel (Zone J)		267,135,214				

	LMS100 PA - Overnight Capital Cost - 2013\$\$					
	K - Long Island	J - NYC	G - Hudson Valley (Dutchess)	G2 - Hudson Valley (Rockland)	F - Capital	C - Central
Non-EPC Cost Components						
Owner's Costs						
Permitting	2,410,000	2,759,000	2,153,000	2,210,000	2,066,000	2,038,000
Legal	2,410,000	2,759,000	2,153,000	2,210,000	2,066,000	2,038,000
Owner's Project Mgmt. & Misc. Eng	3,615,000	4,139,000	3,230,000	3,316,000	3,099,000	3,058,000
Social Justice	482,000	2,483,000	431,000	442,000	413,000	408,000
Owner's Development Costs	7,230,000	8,277,000	6,459,000	6,631,000	6,199,000	6,115,000
Financing Fees	4,820,000	5,518,000	4,306,000	4,421,000	4,133,000	4,077,000
Studies (Fin, Env, Market, Intercon)	1,205,000	1,380,000	1,077,000	1,105,000	1,033,000	1,019,000
Emission Reduction Credits	1,140,000	1,140,000	0	0	0	0
Subtotal	23,312,000	28,455,000	19,809,000	20,335,000	19,009,000	18,753,000
Financing (incl. AFUDC, IDC)						
EPC Portion	11,257,000	12,888,000	10,057,000	10,325,000	9,652,000	9,521,000
Non-EPC Portion	1,089,000	1,329,000	925,000	950,000	888,000	876,000
Working Capital and Inventories	4,820,000	5,518,000	4,306,000	4,421,000	4,133,000	4,077,000
Subtotal - Non-EPC Costs	40,478,000	48,190,000	35,097,000	36,031,000	33,682,000	33,227,000
Total Capital Investment	281,475,000	324,100,000	250,410,000	257,080,000	240,310,000	237,063,000
Cost Reduction if Single Fuel		10,271,000				

	LMS100 PA - Overnight Capital Cost - 2013\$s					
	K - Long Island	J - NYC	G - Hudson Valley (Dutchess)	G - Hudson Valley (Rockland)	F - Capital	C - Central
EPC Cost Components						
Equipment						
Equipment	113,278,000	117,879,000	117,461,000	117,461,000	114,219,000	107,553,000
Spare Parts	1,126,000	1,126,000	1,126,000	1,126,000	1,126,000	1,126,000
Subtotal	114,404,000	119,005,000	118,587,000	118,587,000	115,345,000	108,679,000
Construction						
Construction Labor & Materials	85,336,000	95,008,000	67,367,000	72,387,000	57,716,000	53,646,000
Plant Switchyard	4,516,000	7,346,000	4,619,000	4,771,000	4,285,000	4,193,000
Electrical Interconnection & Deliverability	9,980,000	13,009,000	10,047,000	10,047,000	9,573,000	9,573,000
Gas Interconnect & Reinforcement	5,395,000	6,347,000	5,395,000	5,395,000	5,395,000	5,395,000
Site Prep	3,779,000	6,381,000	3,292,000	3,440,000	2,768,000	2,700,000
Engineering & Design	11,192,000	12,151,000	10,433,000	10,721,000	9,688,000	9,098,000
Construction Mgmt. / Field Engr.	2,798,000	3,038,000	2,608,000	2,681,000	2,422,000	2,275,000
Subtotal	122,996,000	143,280,000	103,761,000	109,442,000	91,847,000	86,880,000
Startup & Testing						
Startup & Training	1,865,000	2,025,000	1,739,000	1,787,000	1,615,000	1,516,000
Testing	-	-	-	-	-	-
Subtotal	1,865,000	2,025,000	1,739,000	1,787,000	1,615,000	1,516,000
Contingency	22,263,000	24,170,000	20,752,000	21,324,000	19,271,000	18,098,000
Subtotal - EPC Costs	261,528,000	288,480,000	244,839,000	251,140,000	228,078,000	215,173,000
EPC Costs for Single Fuel (Zones J & G)		279,703,485	237,668,000	243,776,000		

	LMS100 PA - Overnight Capital Cost - 2013\$\$					
	K - Long Island	J - NYC	G - Hudson Valley (Dutchess)	G - Hudson Valley (Rockland)	F - Capital	C - Central
Non-EPC Cost Components						
Owner's Costs						
Permitting	2,615,000	2,885,000	2,448,000	2,511,000	2,281,000	2,152,000
Legal	2,615,000	2,885,000	2,448,000	2,511,000	2,281,000	2,152,000
Owner's Project Mgmt. & Misc. Engr.	3,923,000	4,327,000	3,673,000	3,767,000	3,421,000	3,228,000
Social Justice	523,000	2,596,000	490,000	502,000	456,000	430,000
Owner's Development Costs	7,846,000	8,654,000	7,345,000	7,534,000	6,842,000	6,455,000
Financing Fees	5,231,000	5,770,000	4,897,000	5,023,000	4,562,000	4,303,000
Studies (Fin, Env, Market, Interconnect)	1,308,000	1,442,000	1,224,000	1,256,000	1,140,000	1,076,000
Emission Reduction Credits	1,144,000	1,144,000	1,346,000	1,346,000	0	0
Subtotal	25,205,000	29,703,000	23,871,000	24,450,000	20,983,000	19,796,000
Financing (incl. AFUDC, IDC)						
EPC Portion	12,216,000	13,475,000	11,436,000	11,731,000	10,654,000	10,051,000
Non-EPC Portion	1,177,000	1,387,000	1,115,000	1,142,000	980,000	925,000
Working Capital and Inventories	5,231,000	5,770,000	4,897,000	5,023,000	4,562,000	4,303,000
Subtotal - Non-EPC Costs	43,829,000	50,335,000	41,319,000	42,346,000	37,179,000	35,075,000
Total Capital Investment	305,357,000	338,815,000	286,158,000	293,486,000	265,257,000	250,248,000
Cost Reduction if Single Fuel		10,273,000	8,342,000	8,566,000		

Table A-4 — Capital Cost Estimates for Combined Cycle - (2013 \$)

	SGT6 - Overnight Capital Cost - 2013\$s					
	K - Long Island	J - NYC	G - Hudson Valley (Dutchess)	G2 - Hudson Valley (Rockland)	F - Capital	C - Central
EPC Cost Components						
Equipment						
Equipment	119,137,000	129,442,000	119,137,000	119,137,000	119,137,000	119,137,000
Spare Parts	1,126,000	1,126,000	1,126,000	1,126,000	1,126,000	1,126,000
Subtotal	120,263,000	130,568,000	120,263,000	120,263,000	120,263,000	120,263,000
Construction						
Construction Labor & Materials	221,120,000	251,580,000	165,140,000	177,092,000	143,526,000	137,789,000
Plant Switchyard	5,468,000	7,346,000	4,619,000	4,771,000	4,285,000	4,193,000
Electrical Interconnection & Delivery	0	0	0	0	0	0
Gas Interconnect & Reinforcement	6,049,000	7,116,000	6,049,000	6,049,000	6,049,000	6,049,000
Site Prep	7,744,000	8,609,000	6,203,000	6,488,000	5,696,000	5,415,000
Engineering & Design	17,201,000	19,318,000	14,361,000	14,964,000	13,268,000	12,971,000
Construction Mgmt. / Field Engr.	6,255,000	7,025,000	5,222,000	5,441,000	4,825,000	4,717,000
Subtotal	263,837,000	300,994,000	201,594,000	214,805,000	177,649,000	171,134,000
Startup & Testing						
Startup & Training	3,127,000	3,512,000	2,611,000	2,721,000	2,412,000	2,358,000
Testing	-	-	-	-	-	-
Subtotal	3,127,000	3,512,000	2,611,000	2,721,000	2,412,000	2,358,000
Contingency	38,005,000	42,683,000	31,729,000	33,061,000	29,315,000	28,658,000
Subtotal - EPC Costs	425,232,000	477,757,000	356,197,000	370,850,000	329,639,000	322,413,000
EPC Costs for Single Fuel (Zone J)		469,341,213				

	SGT6 - Overnight Capital Cost - 2013\$\$					
	K - Long Island	J - NYC	G - Hudson Valley (Dutchess)	G2 - Hudson Valley (Rockland)	F - Capital	C - Central
Non-EPC Cost Components						
Owner's Costs						
Permitting	4,252,000	4,778,000	3,562,000	3,709,000	3,296,000	3,224,000
Legal	4,252,000	4,778,000	3,562,000	3,709,000	3,296,000	3,224,000
Owner's Project Mgmt. & Misc. Eng	6,378,000	7,166,000	5,343,000	5,563,000	4,945,000	4,836,000
Social Justice	850,000	4,300,000	712,000	742,000	659,000	645,000
Owner's Development Costs	12,757,000	14,333,000	10,686,000	11,126,000	9,889,000	9,672,000
Financing Fees	8,505,000	9,555,000	7,124,000	7,417,000	6,593,000	6,448,000
Studies (Fin, Env, Market, Intercon)	2,126,000	2,389,000	1,781,000	1,854,000	1,648,000	1,612,000
Emission Reduction Credits	2,700,000	2,780,000	2,380,000	2,380,000	2,380,000	1,230,000
Subtotal	41,820,000	50,079,000	35,150,000	36,500,000	32,706,000	30,891,000
Financing (incl. AFUDC, IDC)						
EPC Portion	40,023,000	44,966,000	33,525,000	34,904,000	31,026,000	30,346,000
Non-EPC Portion	3,936,000	4,713,000	3,308,000	3,435,000	3,078,000	2,907,000
Working Capital and Inventories	8,505,000	9,555,000	7,124,000	7,417,000	6,593,000	6,448,000
Subtotal - Non-EPC Costs	94,284,000	109,313,000	79,107,000	82,256,000	73,403,000	70,592,000
Total Capital Investment	519,516,000	587,070,000	435,304,000	453,106,000	403,042,000	393,005,000
Cost Reduction if Single Fuel		10,292,000				

	SGT6 - Overnight Capital Cost - 2013\$\$					
	K - Long Island	J - NYC	G - Hudson Valley (Dutchess)	G - Hudson Valley (Rockland)	F - Capital	C - Central
EPC Cost Components						
Equipment						
Equipment	126,760,000	131,919,000	132,091,000	132,091,000	128,328,000	119,137,000
Spare Parts	1,126,000	1,126,000	1,126,000	1,126,000	1,126,000	1,126,000
Subtotal	127,886,000	133,045,000	133,217,000	133,217,000	129,454,000	120,263,000
Construction						
Construction Labor & Materials	223,129,000	251,551,000	169,035,000	181,470,000	145,460,000	137,789,000
Plant Switchyard	4,516,000	7,346,000	4,619,000	4,771,000	4,285,000	4,193,000
Electrical Interconnection & Deliverability	9,980,000	13,009,000	10,047,000	10,047,000	9,573,000	9,573,000
Gas Interconnect & Reinforcement	6,049,000	7,116,000	6,049,000	6,049,000	6,049,000	6,049,000
Site Prep	7,190,000	7,998,000	6,146,000	6,422,000	5,388,000	5,415,000
Engineering & Design	17,597,000	19,408,000	15,177,000	15,804,000	13,794,000	12,971,000
Construction Mgmt. / Field Engr.	6,399,000	7,057,000	5,520,000	5,748,000	5,016,000	4,717,000
Subtotal	274,860,000	313,485,000	216,593,000	230,311,000	189,565,000	180,707,000
Startup & Testing						
Startup & Training	3,199,000	3,529,000	2,759,000	2,873,000	2,508,000	2,358,000
Testing	-	-	-	-	-	-
Subtotal	3,199,000	3,529,000	2,759,000	2,873,000	2,508,000	2,358,000
Contingency	38,879,000	42,881,000	33,535,000	34,918,000	30,478,000	28,658,000
Subtotal - EPC Costs	444,824,000	492,940,000	386,104,000	401,319,000	352,005,000	331,986,000
EPC Costs for Single Fuel (Zones J & G)		484,524,320	379,112,000	394,217,000		

	SGT6 - Overnight Capital Cost - 2013\$s					
	K - Long Island	J - NYC	G - Hudson Valley (Dutchess)	G - Hudson Valley (Rockland)	F - Capital	C - Central
Non-EPC Cost Components						
Owner's Costs						
Permitting	4,448,000	4,929,000	3,861,000	4,013,000	3,520,000	3,320,000
Legal	4,448,000	4,929,000	3,861,000	4,013,000	3,520,000	3,320,000
Owner's Project Mgmt. & Misc. Engr.	6,672,000	7,394,000	5,792,000	6,020,000	5,280,000	4,980,000
Social Justice	890,000	4,436,000	772,000	803,000	704,000	664,000
Owner's Development Costs	13,345,000	14,788,000	11,583,000	12,040,000	10,560,000	9,960,000
Financing Fees	8,896,000	9,859,000	7,722,000	8,026,000	7,040,000	6,640,000
Studies (Fin, Env, Market, Interconnect)	2,224,000	2,465,000	1,931,000	2,007,000	1,760,000	1,660,000
Emission Reduction Credits	2,700,000	2,780,000	2,380,000	2,380,000	2,380,000	1,230,000
Subtotal	43,623,000	51,580,000	37,902,000	39,302,000	34,764,000	31,774,000
Financing (incl. AFUDC, IDC)						
EPC Portion	41,867,000	46,396,000	36,340,000	37,772,000	33,131,000	31,247,000
Non-EPC Portion	4,106,000	4,855,000	3,567,000	3,699,000	3,272,000	2,991,000
Working Capital and Inventories	8,896,000	9,859,000	7,722,000	8,026,000	7,040,000	6,640,000
Subtotal - Non-EPC Costs	98,492,000	112,690,000	85,531,000	88,799,000	78,207,000	72,652,000
Total Capital Investment	543,316,000	605,630,000	471,635,000	490,118,000	430,212,000	404,638,000
Cost Reduction if Single Fuel		10,292,000	8,498,000	8,631,000		

Table A-5 — Capital Cost Estimates for Reciprocating Engine - (2013 \$)

	18V50 - Overnight Capital Cost - 2013\$s					
	K - Long Island	J - NYC	G - Hudson Valley (Dutchess)	G2 - Hudson Valley (Rockland)	F - Capital	C - Central
EPC Cost Components						
Equipment						
Equipment	150,617,000	157,036,000	150,617,000	150,617,000	150,617,000	150,617,000
Spare Parts	1,126,000	1,126,000	1,126,000	1,126,000	1,126,000	1,126,000
Subtotal	151,743,000	158,162,000	151,743,000	151,743,000	151,743,000	151,743,000
Construction						
Construction Labor & Materials	144,996,000	167,461,000	107,408,000	114,740,000	94,060,000	90,213,000
Plant Switchyard	5,468,000	7,346,000	4,619,000	4,771,000	4,285,000	4,193,000
Electrical Interconnection & Delivery	0	0	0	0	0	0
Gas Interconnect & Reinforcement	5,395,000	6,347,000	5,395,000	5,395,000	5,395,000	5,395,000
Site Prep	6,285,000	7,078,000	4,956,000	5,204,000	4,529,000	4,292,000
Engineering & Design	14,146,000	15,598,000	12,316,000	12,672,000	11,667,000	11,474,000
Construction Mgmt. / Field Engr.	5,658,000	6,239,000	4,926,000	5,069,000	4,667,000	4,590,000
Subtotal	181,948,000	210,069,000	139,620,000	147,851,000	124,603,000	120,157,000
Startup & Testing						
Startup & Training	2,829,000	3,120,000	2,463,000	2,534,000	2,333,000	2,295,000
Testing	-	-	-	-	-	-
Subtotal	2,829,000	3,120,000	2,463,000	2,534,000	2,333,000	2,295,000
Contingency	33,000,000	36,388,000	28,730,000	29,561,000	27,216,000	26,767,000
Subtotal - EPC Costs	369,520,000	407,739,000	322,556,000	331,689,000	305,895,000	300,962,000
EPC Costs for Single Fuel (Zone J)		395,378,706				

	18V50 - Overnight Capital Cost - 2013\$\$s					
	K - Long Island	J - NYC	G - Hudson Valley (Dutchess)	G2 - Hudson Valley (Rockland)	F - Capital	C - Central
Non-EPC Cost Components						
Owner's Costs						
Permitting	3,695,000	4,077,000	3,226,000	3,317,000	3,059,000	3,010,000
Legal	3,695,000	4,077,000	3,226,000	3,317,000	3,059,000	3,010,000
Owner's Project Mgmt. & Misc. Eng	5,543,000	6,116,000	4,838,000	4,975,000	4,588,000	4,514,000
Social Justice	739,000	3,670,000	645,000	663,000	612,000	602,000
Owner's Development Costs	11,086,000	12,232,000	9,677,000	9,951,000	9,177,000	9,029,000
Financing Fees	7,390,000	8,155,000	6,451,000	6,634,000	6,118,000	6,019,000
Studies (Fin, Env, Market, Intercon)	1,848,000	2,039,000	1,613,000	1,658,000	1,529,000	1,505,000
Emission Reduction Credits	5,060,000	6,240,000	4,480,000	4,480,000	4,480,000	5,300,000
Subtotal	39,056,000	46,606,000	34,156,000	34,995,000	32,622,000	32,989,000
Financing (incl. AFUDC, IDC)						
EPC Portion	17,031,000	18,793,000	14,867,000	15,288,000	14,099,000	13,871,000
Non-EPC Portion	1,800,000	2,148,000	1,574,000	1,613,000	1,504,000	1,520,000
Working Capital and Inventories	7,390,000	8,155,000	6,451,000	6,634,000	6,118,000	6,019,000
Subtotal - Non-EPC Costs	65,277,000	75,702,000	57,048,000	58,530,000	54,343,000	54,399,000
Total Capital Investment	434,797,000	483,441,000	379,604,000	390,219,000	360,238,000	355,361,000
Cost Reduction if Single Fuel		14,466,000				

	18V50 - Overnight Capital Cost - 2013\$s					
	K - Long Island	J - NYC	G - Hudson Valley (Dutchess)	G - Hudson Valley (Rockland)	F - Capital	C - Central
EPC Cost Components						
Equipment						
Equipment	149,781,000	157,036,000	157,872,000	157,872,000	150,617,000	150,617,000
Spare Parts	1,126,000	1,126,000	1,126,000	1,126,000	1,126,000	1,126,000
Subtotal	150,907,000	158,162,000	158,998,000	158,998,000	151,743,000	151,743,000
Construction						
Construction Labor & Materials	145,190,000	167,461,000	109,660,000	117,098,000	94,060,000	90,213,000
Plant Switchyard	7,253,000	7,346,000	4,619,000	4,771,000	4,285,000	4,193,000
Electrical Interconnection & Deliverability	9,980,000	13,009,000	10,047,000	10,047,000	9,573,000	9,573,000
Gas Interconnect & Reinforcement	5,395,000	6,347,000	5,395,000	5,395,000	5,395,000	5,395,000
Site Prep	6,285,000	7,078,000	5,279,000	5,541,000	4,529,000	4,292,000
Engineering & Design	14,199,000	15,598,000	12,768,000	13,130,000	11,667,000	11,474,000
Construction Mgmt. / Field Engr.	5,679,000	6,239,000	5,107,000	5,252,000	4,667,000	4,590,000
Subtotal	193,981,000	223,078,000	152,875,000	161,234,000	134,176,000	129,730,000
Startup & Testing						
Startup & Training	2,840,000	3,120,000	2,554,000	2,626,000	2,333,000	2,295,000
Testing	-	-	-	-	-	-
Subtotal	2,840,000	3,120,000	2,554,000	2,626,000	2,333,000	2,295,000
Contingency	33,123,000	36,388,000	29,786,000	30,629,000	27,216,000	26,767,000
Subtotal - EPC Costs	380,851,000	420,748,000	344,213,000	353,487,000	315,468,000	310,535,000
EPC Costs for Single Fuel (Zones J & G)		408,387,706	332,603,000	341,736,000		

	18V50 - Overnight Capital Cost - 2013\$s					
	K - Long Island	J - NYC	G - Hudson Valley (Dutchess)	G - Hudson Valley (Rockland)	F - Capital	C - Central
Non-EPC Cost Components						
Owner's Costs						
Permitting	3,809,000	4,207,000	3,442,000	3,535,000	3,155,000	3,105,000
Legal	3,809,000	4,207,000	3,442,000	3,535,000	3,155,000	3,105,000
Owner's Project Mgmt. & Misc. Engr.	5,713,000	6,311,000	5,163,000	5,302,000	4,732,000	4,658,000
Social Justice	762,000	3,787,000	688,000	707,000	631,000	621,000
Owner's Development Costs	11,426,000	12,622,000	10,326,000	10,605,000	9,464,000	9,316,000
Financing Fees	7,617,000	8,415,000	6,884,000	7,070,000	6,309,000	6,211,000
Studies (Fin, Env, Market, Interconnect)	1,904,000	2,104,000	1,721,000	1,767,000	1,577,000	1,553,000
Emission Reduction Credits	5,057,000	6,435,000	5,520,000	5,520,000	4,497,000	5,302,000
Subtotal	40,097,000	48,088,000	37,186,000	38,041,000	33,520,000	33,871,000
Financing (incl. AFUDC, IDC)						
EPC Portion	17,553,000	19,392,000	15,865,000	16,292,000	14,540,000	14,313,000
Non-EPC Portion	1,848,000	2,216,000	1,714,000	1,753,000	1,545,000	1,561,000
Working Capital and Inventories	7,617,000	8,415,000	6,884,000	7,070,000	6,309,000	6,211,000
Subtotal - Non-EPC Costs	67,115,000	78,111,000	61,649,000	63,156,000	55,914,000	55,956,000
Total Capital Investment	447,966,000	498,859,000	405,862,000	416,643,000	371,382,000	366,491,000
Cost Reduction if Single Fuel		14,466,000	13,503,000	13,667,000		

Table A-6 — Comparison of Capital Cost Estimates – LMS100 in NYC

	Capital Cost Comparison 2 x LMS100 Zone J - NYC					
	2013 DC Reset		2010 DC Reset		2007 DC Reset	
	Cost (2013\$)	Non- EPC as % of EPC	Cost (2010\$)	Non- EPC as % of EPC	Cost (2010\$)	Non- EPC as % of EPC
EPC Cost Components						
Equipment						
Equipment	117,879,000		117,943,000		89,050,000	
Spare Parts	1,126,000		1,061,000		1,000,000	
Subtotal	119,005,000		119,004,000		90,050,000	
Construction						
Construction Labor & Materials	95,379,000		94,244,000		68,129,000	
Electrical Connection & Substation	7,346,000		5,925,000		3,793,000	
Electrical System Upgrades	0		4,800,000		500,000	
Gas Interconnect & Reinforcement	6,347,000		5,740,000		5,000,000	
Site Prep	6,381,000		6,017,000		2,491,000	
Engineering & Design	12,171,000		11,792,000		8,562,000	
Construction Mgmt. / Field Engr.	3,043,000		2,948,000		2,140,000	
Subtotal	130,667,000		131,466,000		90,615,000	
Startup & Testing						
Startup & Training	2,028,000		1,965,000		1,427,000	
Testing	-		-		-	
Subtotal	2,028,000		1,965,000		1,427,000	
Contingency	24,210,000		23,883,000		17,031,000	
Subtotal - EPC Costs	275,910,000		276,318,000		199,123,000	
Non-EPC Cost Components						
Owner's Costs						
Permitting	2,759,000	1.00%	2,763,000	1.00%	1,991,000	1.00%
Legal	2,759,000	1.00%	5,526,000	2.00%	3,982,000	2.00%
Owner's Project Mgmt. & Misc. Eng	4,139,000	1.50%	5,526,000	2.00%	3,982,000	2.00%
Social Justice	2,483,000	0.90%	2,487,000	0.90%	2,000,000	1.00%
Owner's Development Costs	8,277,000	3.00%	8,290,000	3.00%	5,974,000	3.00%
Financing Fees	5,518,000	2.00%	956,000	0.35%	3,982,000	2.00%
Studies (Fin, Env, Market, Interconn)	1,380,000	0.50%	2,764,000	1.00%	1,992,000	1.00%
Emission Reduction Credits	1,140,000	0.41%	750,000	0.27%	0	0.00%
Subtotal	28,455,000	10.31%	29,062,000	10.52%	23,903,000	12.00%
Financing (incl. AFUDC, IDC)						
EPC Portion	12,888,000	4.67%	13,844,000	5.01%	9,060,000	4.55%
Non-EPC Portion	1,329,000	0.48%	1,456,000	0.53%	1,088,000	0.55%
Working Capital and Inventories	5,518,000	2.00%	5,526,000	2.00%	3,982,000	2.00%
Subtotal - Non-EPC Costs	48,190,000	17.47%	49,888,000	18.05%	38,033,000	19.10%
Total Capital Investment	324,100,000	117.47%	326,206,000	118.05%	237,156,000	119.10%

Capital Cost Comparison 2 x LMS100 Zone J - NYC						
2013 DC Reset			2010 DC Reset		2007 DC Reset	
Cost (2013\$)	Non- EPC as % of EPC		Cost (2010\$)	Non- EPC as % of EPC	Cost (2010\$)	Non- EPC as % of EPC
EPC Cost Components						
Equipment						
Equipment	117,879,000		117,943,000		89,050,000	
Spare Parts	1,126,000		1,061,000		1,000,000	
Subtotal	119,005,000		119,004,000		90,050,000	
Construction						
Construction Labor & Materials	95,008,000		94,244,000		68,129,000	
Plant Switchyard	7,346,000		5,925,000		3,793,000	
Electrical Interconnection & Delivery	13,009,000		4,800,000		500,000	
Gas Interconnect & Reinforcement	6,347,000		5,740,000		5,000,000	
Site Prep	6,381,000		6,017,000		2,491,000	
Engineering & Design	12,151,000		11,792,000		8,562,000	
Construction Mgmt. / Field Engr.	3,038,000		2,948,000		2,140,000	
Subtotal	143,280,000		131,466,000		90,615,000	
Startup & Testing						
Startup & Training	2,025,000		1,965,000		1,427,000	
Testing	-		-		-	
Subtotal	2,025,000		1,965,000		1,427,000	
Contingency	24,170,000		23,883,000		17,031,000	
Subtotal - EPC Costs	288,480,000		276,318,000		199,123,000	
Non-EPC Cost Components						
Owner's Costs						
Permitting	2,885,000	1.00%	2,763,000	1.00%	1,991,000	1.00%
Legal	2,885,000	1.00%	5,526,000	2.00%	3,982,000	2.00%
Owner's Project Mgmt. & Misc. Eng.	4,327,000	1.50%	5,526,000	2.00%	3,982,000	2.00%
Social Justice	2,596,000	0.90%	2,487,000	0.90%	2,000,000	1.00%
Owner's Development Costs	8,654,000	3.00%	8,290,000	3.00%	5,974,000	3.00%
Financing Fees	5,770,000	2.00%	956,000	0.35%	3,982,000	2.00%
Studies (Fin, Env, Market, Interconn)	1,442,000	0.50%	2,764,000	1.00%	1,992,000	1.00%
Emission Reduction Credits	1,144,000	0.40%	750,000	0.27%	0	0.00%
Subtotal	29,703,000	10.30%	29,062,000	10.52%	23,903,000	12.00%
Financing (incl. AFUDC, IDC)						
EPC Portion	13,475,000	4.67%	13,844,000	5.01%	9,060,000	4.55%
Non-EPC Portion	1,387,000	0.48%	1,456,000	0.53%	1,088,000	0.55%
Working Capital and Inventories	5,770,000	2.00%	5,526,000	2.00%	3,982,000	2.00%
Subtotal - Non-EPC Costs	50,335,000	17.45%	49,888,000	18.05%	38,033,000	19.10%
Total Capital Investment	338,815,000	117.45%	326,206,000	118.05%	237,156,000	119.10%

Table A-7 — Start Up Times

LMS100

Conventional Start

<u>Type</u>	<u>Total Heat Consumption</u>	<u>Total Time</u>
<u>Cold (> 72 Hours Shutdown)</u>	<u>28 mmBtu (LHV)</u>	<u>10 minutes</u>
<u>Warm (< 48 Hours Shutdown)</u>	<u>28 mmBtu (LHV)</u>	<u>10 minutes</u>
<u>Hot (< 8 Hours Shutdown)</u>	<u>28 mmBtu (LHV)</u>	<u>10 minutes</u>

1x1x1 SGT6-5000F(5)

Conventional Start

<u>Type</u>	<u>Total Heat Consumption</u>	<u>Total Time</u>
<u>Cold (> 72 Hours Shutdown)</u>	<u>2951 mmBtu (HHV)</u>	<u>227 minutes</u>
<u>Warm (< 48 Hours Shutdown)</u>	<u>1874 mmBtu (HHV)</u>	<u>130 minutes</u>
<u>Hot (< 8 Hours Shutdown)</u>	<u>1523 mmBtu (HHV)</u>	<u>80 minutes</u>

Fast Start (With Purge Credit Fast Acceleration and Loading)⁵⁹

<u>Type</u>	<u>Total Heat Consumption</u>	<u>Total Time</u>
<u>Cold (> 72 Hours Shutdown)</u>	<u>5668 mmBtu (HHV)</u>	<u>125 minutes</u>
<u>Warm (< 48 Hours Shutdown)</u>	<u>3045 mmBtu (HHV)</u>	<u>87 minutes</u>
<u>Hot (< 8 Hours Shutdown)</u>	<u>1148 mmBtu (HHV)</u>	<u>38 minutes</u>

18V50

Conventional Start

<u>Type</u>	<u>Total Heat Consumption</u>	<u>Total Time</u>
<u>Preheated⁶⁰</u>	<u>11 mmBtu (LHV)</u>	<u>10 minutes</u>

⁵⁹ Purge credit refers to the "purge" of gas from the HRSG before each start-up. The is done by spinning the combustion turbine via mechanical means to push air through the HRSG. Normally the purge takes about 5 minutes at the beginning of the startup period, depending on the size of the HRSG. The purge can also be done at the shutdown of the unit or some intermediate time assuming the proper valving and monitoring is in place, and is called a purge credit. Assuming a purge credit, the combustion turbine ramps to full load in the first twenty minutes of the fast start. It remains at full load through the duration of the steam turbine startup. During a conventional start, the combustion turbine operates at a low load while the steam turbine warms, and ramps to full load quickly at the end of the start as the steam turbine starts up.

⁶⁰ If preheater is not used, unit might take up to 12 hours to heat up, depending on initial starting temperature. Preheater is always provided and is normally assumed to be on.

B. Appendix 2 – Financial Assumptions

Table B-1 — Real Carrying Charges on Capital Investment

Merchant Generator Example

Calendar Year	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Operating Year	1	2	3	4	5	6	7	8	9	10	11	12	13	14
Loan Period Parameter	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Equity Period Parameter	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Evaluation Period Factor	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Property Tax and Insurance Escalation Factor	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
NYC Property Tax Exemption	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Effective Income Tax Rate	39.615%	39.615%	39.615%	39.615%	39.615%	39.615%	39.615%	39.615%	39.615%	39.615%	39.615%	39.615%	39.615%	39.615%
Total Project Capitalized Cost	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000
Market Value	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000
Tax Depreciation	5,000%	9,500%	8,550%	7,700%	6,930%	6,230%	5,900%	5,900%	5,910%	5,900%	5,910%	5,900%	5,910%	5,900%
Effective Tax Depreciation	5,000%	9,500%	8,550%	7,700%	6,930%	6,230%	5,900%	5,900%	5,910%	5,900%	5,910%	5,900%	5,910%	5,900%
Depreciated Value	1,000,000	950,000	855,000	769,500	692,500	623,200	560,900	501,900	442,900	383,800	324,800	265,700	206,700	147,600
Financing														
DEBT SERVICE:	500,000													
Loan Balance Start of Year	500,000	488,164	475,842	463,013	449,659	435,756	421,282	406,214	390,527	374,196	357,195	339,496	321,070	301,888
Principal	11,836	12,322	12,828	13,355	13,903	14,474	15,068	15,687	16,331	17,001	17,699	18,426	19,182	19,970
Interest	20,528	20,042	19,536	19,009	18,461	17,890	17,296	16,677	16,033	15,363	14,665	13,938	13,182	12,394
Balance at End of Year	488,164	475,842	463,013	449,659	435,756	421,282	406,214	390,527	374,196	357,195	339,496	321,070	301,888	281,918
EQUITY:	500,000													
TOTAL FINANCING	1,000,000													
Income Statement (Check)														
Carrying Charge Revenues:	91,390	62,187	68,751	74,673	80,084	85,051	87,606	88,012	88,368	88,874	89,266	89,809	90,239	90,821
Capital Related Expenses:														
Property Taxes	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Insurance	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Tax Depreciation	50,000	95,000	85,500	77,000	69,300	62,300	59,000	59,000	59,100	59,000	59,100	59,000	59,100	59,000
Interest Expenses	20,528	20,042	19,536	19,009	18,461	17,890	17,296	16,677	16,033	15,363	14,665	13,938	13,182	12,394
Taxable Income	20,862	-52,855	-36,285	-21,336	-7,677	4,861	11,310	12,334	13,235	14,511	15,501	16,870	17,957	19,427
Income Taxes	8,264	-20,939	-14,374	-8,452	-3,041	1,926	4,480	4,886	5,243	5,749	6,141	6,683	7,114	7,696
Principal	11,836	12,322	12,828	13,355	13,903	14,474	15,068	15,687	16,331	17,001	17,699	18,426	19,182	19,970
Cash Flow to Equity IRR =	9.48%	-500,000	50,761	50,761	50,761	50,761	50,761	50,761	50,761	50,761	50,761	50,761	50,761	50,761
Derivation of Carrying Charges														
Target Equity IRR =	9.48%													
Principal	-	11,836	12,322	12,828	13,355	13,903	14,474	15,068	15,687	16,331	17,001	17,699	18,426	19,970
Interest Expenses	-	20,528	20,042	19,536	19,009	18,461	17,890	17,296	16,677	16,033	15,363	14,665	13,938	13,182
Target Cash Flow to Equity	-	50,761	50,761	50,761	50,761	50,761	50,761	50,761	50,761	50,761	50,761	50,761	50,761	50,761
Income Taxes	-	8,264	-20,939	-14,374	-8,452	-3,041	1,926	4,480	4,886	5,243	5,749	6,141	6,683	7,114
Property Taxes and Insurance	-	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Carrying Charges	-	91,390	62,187	68,751	74,673	80,084	85,051	87,606	88,012	88,368	88,874	89,266	89,809	90,239
Annual Rate (% of initial capital investment)		9.14%	6.22%	6.88%	7.47%	8.01%	8.51%	8.76%	8.80%	8.84%	8.89%	8.93%	8.98%	9.02%
After-Tax Cost of Capital =		5.98%												
Present Value Factor		0.9436	0.8903	0.8401	0.7927	0.7479	0.7057	0.6659	0.6283	0.5929	0.5594	0.5279	0.4981	0.4700
Present Value		86,233	55,366	57,757	59,191	59,899	60,024	58,338	55,301	52,392	49,718	47,119	44,731	42,409
Cumulative Present Value		86,233	141,599	199,356	258,547	318,446	378,469	436,807	492,108	544,499	594,217	641,337	686,067	728,476
Levelized Carrying Charges (Real)		93,733												
Levelized Carrying Charge Rate (Real) =		9.37%												

Calendar Year	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Operating Year	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
Loan Period Parameter	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	0.00	0.00	0.00	0.00	0.00
Equity Period Parameter	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Evaluation Period Factor	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Property Tax and Insurance Escalation Factor	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
NYC Property Tax Exemption	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Effective Income Tax Rate	39.615%	39.615%	39.615%	39.615%	39.615%	39.615%	39.62%	39.62%	39.62%	39.62%	39.62%	39.62%	39.62%	39.62%	39.62%	39.62%
Total Project Capitalized Cost																
Market Value	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000
Tax Depreciation	5.910%	2.950%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
Effective Tax Depreciation	5.910%	2.950%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
Depreciated Value	88,600	29,500	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Financing																
DEBT SERVICE:																
Loan Balance Start of Year	281,918	261,128	239,484	216,953	193,496	169,076	143,653	117,187	89,634	60,950	31,088	0	0	0	0	0
Principal	20,790	21,643	22,532	23,457	24,420	25,423	26,466	27,553	28,684	29,862	31,088	0	0	0	0	0
Interest	11,574	10,721	9,832	8,907	7,944	6,942	5,898	4,811	3,680	2,502	1,276	0	0	0	0	0
Balance at End of Year	261,128	239,484	216,953	193,496	169,076	143,653	117,187	89,634	60,950	31,088	0	0	0	0	0	0
EQUITY:																
TOTAL FINANCING																
Income Statement (Check)																
Carrying Charge Revenues:	91,294	111,272	131,209	131,816	132,447	133,105	133,790	134,503	135,245	136,017	136,822	84,063	84,063	84,063	84,063	84,063
Capital Related Expenses:																
Property Taxes	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Insurance	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Tax Depreciation	59,100	29,500	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Interest Expenses	11,574	10,721	9,832	8,907	7,944	6,942	5,898	4,811	3,680	2,502	1,276	0	0	0	0	0
Taxable Income	20,619	71,052	121,376	122,908	124,503	126,164	127,892	129,691	131,565	133,515	135,545	84,063	84,063	84,063	84,063	84,063
Income Taxes	8,168	28,147	48,083	48,690	49,322	49,980	50,664	51,377	52,119	52,892	53,696	33,301	33,301	33,301	33,301	33,301
Principal	20,790	21,643	22,532	23,457	24,420	25,423	26,466	27,553	28,684	29,862	31,088	0	0	0	0	0
Cash Flow to Equity IRR =	9.48%	50,761	50,761	50,761	50,761	50,761	50,761	50,761	50,761	50,761	50,761	50,761	50,761	50,761	50,761	50,761
Derivation of Carrying Charges																
Target Equity IRR =	9.48%															
Principal	20,790	21,643	22,532	23,457	24,420	25,423	26,466	27,553	28,684	29,862	31,088	0	0	0	0	0
Interest Expenses	11,574	10,721	9,832	8,907	7,944	6,942	5,898	4,811	3,680	2,502	1,276	0	0	0	0	0
Target Cash Flow to Equity	50,761	50,761	50,761	50,761	50,761	50,761	50,761	50,761	50,761	50,761	50,761	50,761	50,761	50,761	50,761	50,761
Income Taxes	8,168	28,147	48,083	48,690	49,322	49,980	50,664	51,377	52,119	52,892	53,696	33,301	33,301	33,301	33,301	33,301
Property Taxes and Insurance	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Carrying Charges	91,294	111,272	131,209	131,816	132,447	133,105	133,790	134,503	135,245	136,017	136,822	84,063	84,063	84,063	84,063	84,063
Annual Rate (% of initial capital investment)	9.13%	11.13%	13.12%	13.18%	13.24%	13.31%	13.38%	13.45%	13.52%	13.60%	13.68%	8.41%	8.41%	8.41%	8.41%	8.41%
After-Tax Cost of Capital =	5.98%															
Present Value Factor	0.4184	0.3948	0.3725	0.3515	0.3317	0.3130	0.2953	0.2786	0.2629	0.2481	0.2341	0.2209	0.2084	0.1966	0.1855	0.1751
Present Value	38,199	43,931	48,879	46,334	43,829	41,656	39,507	37,476	35,557	33,742	32,026	18,566	17,519	16,530	15,597	14,717
Cumulative Present Value	806,949	850,880	899,758	946,092	990,020	1,031,676	1,071,183	1,108,659	1,144,216	1,177,958	1,209,984	1,228,550	1,246,069	1,262,599	1,278,196	1,292,913
Levelized Carrying Charges (Real)																
Levelized Carrying Charge Rate (Real) =																

Calendar Year	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Operating Year	1	2	3	4	5	6	7	8	9	10	11	12	13	14
Loan Period Parameter	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Equity Period Parameter	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Evaluation Period Factor	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Property Tax and Insurance Escalation Factor	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
NYC Property Tax Exemption	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Effective Income Tax Rate	39.615%	39.615%	39.615%	39.615%	39.615%	39.615%	39.615%	39.615%	39.615%	39.615%	39.615%	39.615%	39.615%	39.615%
Total Project Capitalized Cost	1,000,000													
Market Value	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000
Tax Depreciation	5.000%	9.500%	8.550%	7.700%	6.930%	6.230%	5.900%	5.900%	5.910%	5.900%	5.910%	5.900%	5.910%	5.900%
Effective Tax Depreciation	5.000%	9.500%	8.550%	7.700%	6.930%	6.230%	5.900%	5.900%	5.910%	5.900%	5.910%	5.900%	5.910%	5.900%
Depreciated Value	1,000,000	950,000	855,000	769,500	692,500	623,200	560,900	501,900	442,900	383,800	324,800	265,700	206,700	147,600
Financing														
DEBT SERVICE:	500,000													
Loan Balance Start of Year	500,000	488,164	475,842	463,013	449,659	435,756	421,282	406,214	390,527	374,196	357,195	339,496	321,070	301,888
Principal	11,836	12,322	12,828	13,355	13,903	14,474	15,068	15,687	16,331	17,001	17,699	18,426	19,182	19,970
Interest	20,528	20,042	19,536	19,009	18,461	17,890	17,296	16,677	16,033	15,363	14,665	13,938	13,182	12,394
Balance at End of Year	488,164	475,842	463,013	449,659	435,756	421,282	406,214	390,527	374,196	357,195	339,496	321,070	301,888	281,918
EQUITY:	500,000													
TOTAL FINANCING	1,000,000													
Income Statement (Check)														
Carrying Charge Revenues:	91,390	62,187	68,751	74,673	80,084	85,051	87,606	88,012	88,368	88,874	89,266	89,809	90,239	90,821
Capital Related Expenses:														
Property Taxes	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Insurance	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Tax Depreciation	50,000	95,000	85,500	77,000	69,300	62,300	59,000	59,000	59,100	59,000	59,100	59,000	59,100	59,000
Interest Expenses	20,528	20,042	19,536	19,009	18,461	17,890	17,296	16,677	16,033	15,363	14,665	13,938	13,182	12,394
Taxable Income	20,862	-52,855	-36,285	-21,336	-7,677	4,861	11,310	12,334	13,235	14,511	15,501	16,870	17,957	19,427
Income Taxes	8,264	-20,939	-14,374	-8,452	-3,041	1,926	4,480	4,886	5,243	5,749	6,141	6,683	7,114	7,696
Principal	11,836	12,322	12,828	13,355	13,903	14,474	15,068	15,687	16,331	17,001	17,699	18,426	19,182	19,970
Cash Flow to Equity IRR =	9.48%	-500,000	50,761	50,761	50,761	50,761	50,761	50,761	50,761	50,761	50,761	50,761	50,761	50,761
Derivation of Carrying Charges														
Target Equity IRR =	9.48%													
Principal	-	11,836	12,322	12,828	13,355	13,903	14,474	15,068	15,687	16,331	17,001	17,699	18,426	19,970
Interest Expenses	-	20,528	20,042	19,536	19,009	18,461	17,890	17,296	16,677	16,033	15,363	14,665	13,938	12,394
Target Cash Flow to Equity	-	50,761	50,761	50,761	50,761	50,761	50,761	50,761	50,761	50,761	50,761	50,761	50,761	50,761
Income Taxes	-	8,264	-20,939	-14,374	-8,452	-3,041	1,926	4,480	4,886	5,243	5,749	6,141	6,683	7,114
Property Taxes and Insurance	-	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Carrying Charges	-	91,390	62,187	68,751	74,673	80,084	85,051	87,606	88,012	88,368	88,874	89,266	89,809	90,821
Annual Rate (% of initial capital investment)		9.14%	6.22%	6.88%	7.47%	8.01%	8.51%	8.76%	8.80%	8.84%	8.89%	8.93%	8.98%	9.02%
After-Tax Cost of Capital =	5.98%													
Present Value Factor	0.9436	0.8903	0.8401	0.7927	0.7479	0.7057	0.6659	0.6283	0.5929	0.5594	0.5279	0.4981	0.4700	0.4434
Present Value	86,233	55,366	57,757	59,191	59,899	60,024	58,338	55,301	52,392	49,718	47,119	44,731	42,409	40,274
Cumulative Present Value	86,233	141,599	199,356	258,547	318,446	378,469	436,807	492,108	544,499	594,217	641,337	686,067	728,476	768,750
Levelized Carrying Charges (Real)		93,733												
Levelized Carrying Charge Rate (Real) =		9.37%												

Calendar Year	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Operating Year	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30
Loan Period Parameter	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	0.00	0.00	0.00	0.00	0.00
Equity Period Parameter	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Evaluation Period Factor	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Property Tax and Insurance Escalation Factor	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
NYC Property Tax Exemption	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Effective Income Tax Rate	39.615%	39.615%	39.615%	39.615%	39.615%	39.615%	39.62%	39.62%	39.62%	39.62%	39.62%	39.62%	39.62%	39.62%	39.62%	39.62%
Total Project Capitalized Cost																
Market Value	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000
Tax Depreciation	5.910%	2.950%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
Effective Tax Depreciation	5.910%	2.950%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%
Depreciated Value	88,600	29,500	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Financing																
DEBT SERVICE:																
Loan Balance Start of Year	281,918	261,128	239,484	216,953	193,496	169,076	143,653	117,187	89,634	60,950	31,088	0	0	0	0	0
Principal	20,790	21,643	22,532	23,457	24,420	25,423	26,466	27,553	28,684	29,862	31,088	0	0	0	0	0
Interest	11,574	10,721	9,832	8,907	7,944	6,942	5,898	4,811	3,680	2,502	1,276	0	0	0	0	0
Balance at End of Year	261,128	239,484	216,953	193,496	169,076	143,653	117,187	89,634	60,950	31,088	0	0	0	0	0	0
EQUITY:																
TOTAL FINANCING																
Income Statement (Check)																
Carrying Charge Revenues:	91,294	111,272	131,209	131,816	132,447	133,105	133,790	134,503	135,245	136,017	136,822	84,063	84,063	84,063	84,063	84,063
Capital Related Expenses:																
Property Taxes	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Insurance	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Tax Depreciation	59,100	29,500	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Interest Expenses	11,574	10,721	9,832	8,907	7,944	6,942	5,898	4,811	3,680	2,502	1,276	0	0	0	0	0
Taxable Income	20,619	71,052	121,376	122,908	124,503	126,164	127,892	129,691	131,565	133,515	135,545	84,063	84,063	84,063	84,063	84,063
Income Taxes	8,168	28,147	48,083	48,690	49,322	49,980	50,664	51,377	52,119	52,892	53,696	33,301	33,301	33,301	33,301	33,301
Principal	20,790	21,643	22,532	23,457	24,420	25,423	26,466	27,553	28,684	29,862	31,088	0	0	0	0	0
Cash Flow to Equity IRR =	9.48%	50,761	50,761	50,761	50,761	50,761	50,761	50,761	50,761	50,761	50,761	50,761	50,761	50,761	50,761	50,761
Derivation of Carrying Charges																
Target Equity IRR =	9.48%															
Principal	20,790	21,643	22,532	23,457	24,420	25,423	26,466	27,553	28,684	29,862	31,088	0	0	0	0	0
Interest Expenses	11,574	10,721	9,832	8,907	7,944	6,942	5,898	4,811	3,680	2,502	1,276	0	0	0	0	0
Target Cash Flow to Equity	50,761	50,761	50,761	50,761	50,761	50,761	50,761	50,761	50,761	50,761	50,761	50,761	50,761	50,761	50,761	50,761
Income Taxes	8,168	28,147	48,083	48,690	49,322	49,980	50,664	51,377	52,119	52,892	53,696	33,301	33,301	33,301	33,301	33,301
Property Taxes and Insurance	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Carrying Charges	91,294	111,272	131,209	131,816	132,447	133,105	133,790	134,503	135,245	136,017	136,822	84,063	84,063	84,063	84,063	84,063
Annual Rate (% of initial capital investment)	9.13%	11.13%	13.12%	13.18%	13.24%	13.31%	13.38%	13.45%	13.52%	13.60%	13.68%	8.41%	8.41%	8.41%	8.41%	8.41%
After-Tax Cost of Capital =	5.98%															
Present Value Factor	0.4184	0.3948	0.3725	0.3515	0.3317	0.3130	0.2953	0.2786	0.2629	0.2481	0.2341	0.2209	0.2084	0.1966	0.1855	0.1751
Present Value	38,199	43,931	48,879	46,334	43,929	41,656	39,507	37,476	35,557	33,742	32,026	18,566	17,519	16,530	15,597	14,717
Cumulative Present Value	806,949	850,880	899,758	946,092	990,020	1,031,676	1,071,183	1,108,659	1,144,216	1,177,958	1,209,984	1,228,550	1,246,069	1,262,599	1,278,196	1,292,913
Levelized Carrying Charges (Real)																
Levelized Carrying Charge Rate (Real) =																

Table B-2 — Real Levelized Carrying Charge Rates - Results of Sensitivity Analysis

Based on 15-Year MACRS Depreciation (IC Engine and Simple Cycle CT)

Debt Amortization Years * =	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25
Base Case:																
Without Property Taxes and Insurance:																
non-NYC:	10.32%	10.24%	10.17%	10.10%	10.03%	9.96%	9.89%	9.83%	9.77%	9.70%	9.65%	9.59%	9.53%	9.48%	9.42%	9.37%
NYC:	10.81%	10.73%	10.64%	10.56%	10.48%	10.40%	10.33%	10.25%	10.18%	10.11%	10.05%	9.98%	9.92%	9.85%	9.79%	9.73%
With Property Taxes and A07511 Tax Exemption Policy; Without Insurance:																
NYC:	12.19%	12.11%	12.02%	11.94%	11.86%	11.79%	11.71%	11.64%	11.57%	11.50%	11.43%	11.36%	11.30%	11.24%	11.17%	11.12%
With Property Taxes (no exemptions); Without Insurance:																
NYC:	15.44%	15.35%	15.27%	15.19%	15.11%	15.03%	14.96%	14.88%	14.81%	14.74%	14.68%	14.61%	14.55%	14.48%	14.42%	14.36%
200 bp higher on nominal debt and equity cost:																
Without Property Taxes and Insurance:																
non-NYC:	12.34%	12.25%	12.16%	12.08%	11.99%	11.91%	11.83%	11.76%	11.68%	11.61%	11.55%	11.48%	11.42%	11.36%	11.30%	11.24%
NYC:	12.96%	12.86%	12.75%	12.65%	12.56%	12.46%	12.37%	12.29%	12.20%	12.12%	12.04%	11.96%	11.89%	11.82%	11.75%	11.69%
With Property Taxes and A07511 Tax Exemption Policy; Without Insurance:																
NYC:	14.15%	14.04%	13.94%	13.84%	13.74%	13.65%	13.56%	13.47%	13.39%	13.30%	13.23%	13.15%	13.08%	13.00%	12.94%	12.87%
With Property Taxes (no exemptions); Without Insurance:																
NYC:	17.59%	17.48%	17.38%	17.28%	17.19%	17.09%	17.00%	16.91%	16.83%	16.75%	16.67%	16.59%	16.52%	16.45%	16.38%	16.31%
400 bp higher on nominal debt and equity cost:																
Without Property Taxes and Insurance:																
non-NYC:	14.48%	14.37%	14.26%	14.16%	14.06%	13.97%	13.88%	13.79%	13.71%	13.63%	13.56%	13.48%	13.42%	13.35%	13.29%	13.23%
NYC:	15.22%	15.09%	14.97%	14.85%	14.74%	14.63%	14.52%	14.42%	14.33%	14.24%	14.15%	14.06%	13.98%	13.90%	13.83%	13.76%
With Property Taxes and A07511 Tax Exemption Policy; Without Insurance:																
NYC:	16.23%	16.10%	15.98%	15.86%	15.75%	15.64%	15.53%	15.43%	15.34%	15.25%	15.16%	15.07%	14.99%	14.91%	14.84%	14.77%
With Property Taxes (no exemptions); Without Insurance:																
NYC:	19.85%	19.72%	19.60%	19.48%	19.37%	19.26%	19.15%	19.05%	18.96%	18.87%	18.78%	18.69%	18.61%	18.53%	18.46%	18.39%

* In all cases the fixed charge and equity amortization period is 30 years.

Debt Amortization Years * =	26	27	28	29	30	31	32	33	34	35
Base Case:										
Without Property Taxes and Insurance:										
non-NYC:	9.32%	9.27%	9.23%	9.18%	9.14%	9.04%	8.95%	8.86%	8.78%	8.70%
NYC:	9.68%	9.62%	9.57%	9.51%	9.46%	9.35%	9.24%	9.15%	9.05%	8.97%
With Property Taxes and A07511 Tax Exemption Policy; Without Insurance:										
NYC:	11.06%	11.00%	10.95%	10.90%	10.84%	10.73%	10.63%	10.53%	10.44%	10.35%
With Property Taxes (no exemptions); Without Insurance:										
NYC:	14.31%	14.25%	14.20%	14.14%	14.09%	13.98%	13.87%	13.78%	13.68%	13.60%
200 bp higher on nominal debt and equity cost:										
Without Property Taxes and Insurance:										
non-NYC:	11.19%	11.13%	11.08%	11.03%	10.99%	10.89%	10.80%	10.72%	10.64%	10.57%
NYC:	11.62%	11.56%	11.50%	11.44%	11.39%	11.28%	11.17%	11.08%	10.99%	10.91%
With Property Taxes and A07511 Tax Exemption Policy; Without Insurance:										
NYC:	12.81%	12.74%	12.69%	12.63%	12.57%	12.46%	12.36%	12.26%	12.17%	12.09%
With Property Taxes (no exemptions); Without Insurance:										
NYC:	16.25%	16.19%	16.13%	16.07%	16.02%	15.91%	15.80%	15.71%	15.62%	15.54%
400 bp higher on nominal debt and equity cost:										
Without Property Taxes and Insurance:										
non-NYC:	13.17%	13.12%	13.06%	13.02%	12.97%	12.88%	12.79%	12.72%	12.65%	12.59%
NYC:	13.69%	13.63%	13.57%	13.51%	13.45%	13.35%	13.25%	13.16%	13.08%	13.01%
With Property Taxes and A07511 Tax Exemption Policy; Without Insurance:										
NYC:	14.70%	14.64%	14.58%	14.52%	14.46%	14.36%	14.26%	14.17%	14.09%	14.02%
With Property Taxes (no exemptions); Without Insurance:										
NYC:	18.32%	18.26%	18.20%	18.14%	18.08%	17.98%	17.88%	17.79%	17.71%	17.64%

* In all cases the fixed charge and equity amortization period is 30 years.

Debt Amortization Years =	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25
Base Case:																
Without Property Taxes and Insurance:																
non-NYC:	16.48%	15.48%	14.64%	13.92%	13.30%	12.76%	12.28%	11.86%	11.49%	11.16%	10.87%	10.61%	10.38%	10.17%	9.98%	9.80%
NYC:	17.09%	16.06%	15.20%	14.46%	13.82%	13.26%	12.76%	12.32%	11.93%	11.59%	11.28%	11.01%	10.76%	10.54%	10.34%	10.16%
With Property Taxes and A07511 Tax Exemption Policy; Without Insurance:																
NYC:	17.09%	16.06%	15.20%	14.46%	13.82%	13.26%	12.94%	12.66%	12.41%	12.19%	12.00%	11.83%	11.67%	11.53%	11.40%	11.29%
With Property Taxes (no exemptions); Without Insurance:																
non-NYC:	18.48%	17.48%	16.64%	15.92%	15.30%	14.76%	14.28%	13.86%	13.49%	13.16%	12.87%	12.61%	12.38%	12.17%	11.98%	11.80%
NYC:	21.72%	20.69%	19.83%	19.09%	18.45%	17.89%	17.39%	16.95%	16.56%	16.22%	15.91%	15.64%	15.39%	15.17%	14.97%	14.79%
200 bp higher on nominal debt and equity cost:																
Without Property Taxes and Insurance:																
non-NYC:	18.28%	17.28%	16.43%	15.71%	15.08%	14.54%	14.06%	13.64%	13.27%	12.94%	12.66%	12.40%	12.17%	11.97%	11.78%	11.62%
NYC:	19.02%	17.99%	17.11%	16.36%	15.71%	15.14%	14.64%	14.19%	13.81%	13.46%	13.16%	12.89%	12.65%	12.43%	12.24%	12.06%
With Property Taxes and A07511 Tax Exemption Policy; Without Insurance:																
NYC:	19.02%	17.99%	17.11%	16.36%	15.71%	15.14%	14.80%	14.50%	14.23%	13.99%	13.79%	13.60%	13.44%	13.29%	13.16%	13.03%
With Property Taxes (no exemptions); Without Insurance:																
non-NYC:	20.28%	19.28%	18.43%	17.71%	17.08%	16.54%	16.06%	15.64%	15.27%	14.94%	14.66%	14.40%	14.17%	13.97%	13.78%	13.62%
NYC:	23.65%	22.62%	21.74%	20.99%	20.34%	19.77%	19.27%	18.82%	18.44%	18.09%	17.79%	17.52%	17.28%	17.06%	16.86%	16.69%
400 bp higher on nominal debt and equity cost:																
Without Property Taxes and Insurance:																
non-NYC:	20.14%	19.13%	18.28%	17.56%	16.93%	16.39%	15.92%	15.50%	15.14%	14.82%	14.54%	14.30%	14.08%	13.88%	13.71%	13.55%
NYC:	21.01%	19.97%	19.08%	18.33%	17.68%	17.11%	16.60%	16.16%	15.78%	15.44%	15.14%	14.88%	14.65%	14.44%	14.25%	14.08%
With Property Taxes and A07511 Tax Exemption Policy; Without Insurance:																
NYC:	21.01%	19.97%	19.08%	18.33%	17.68%	17.11%	16.75%	16.43%	16.15%	15.91%	15.69%	15.50%	15.33%	15.18%	15.04%	14.92%
With Property Taxes (no exemptions); Without Insurance:																
non-NYC:	22.14%	21.13%	20.28%	19.56%	18.93%	18.39%	17.92%	17.50%	17.14%	16.82%	16.54%	16.30%	16.08%	15.88%	15.71%	15.55%
NYC:	25.64%	24.59%	23.71%	22.96%	22.31%	21.74%	21.23%	20.79%	20.41%	20.07%	19.77%	19.51%	19.28%	19.07%	18.88%	18.71%

Debt Amortization Years =	26	27	28	29	30	31	32	33	34	35
Base Case:										
Without Property Taxes and Insurance:										
non-NYC:	9.65%	9.50%	9.37%	9.25%	9.14%	9.03%	8.94%	8.85%	8.77%	8.70%
NYC:	10.00%	9.84%	9.71%	9.58%	9.46%	9.35%	9.26%	9.16%	9.08%	9.00%
With Property Taxes and A07511 Tax Exemption Policy; Without Insurance:										
NYC:	11.18%	11.09%	11.00%	10.92%	10.84%	10.78%	10.71%	10.65%	10.60%	10.55%
With Property Taxes (no exemptions); Without Insurance:										
non-NYC:	11.65%	11.50%	11.37%	11.25%	11.14%	11.03%	10.94%	10.85%	10.77%	10.70%
NYC:	14.63%	14.47%	14.34%	14.21%	14.09%	13.98%	13.88%	13.79%	13.71%	13.63%
200 bp higher on nominal debt and equity cost:										
Without Property Taxes and Insurance:										
non-NYC:	11.47%	11.33%	11.21%	11.09%	10.99%	10.89%	10.80%	10.72%	10.65%	10.58%
NYC:	11.90%	11.75%	11.62%	11.50%	11.39%	11.29%	11.19%	11.11%	11.03%	10.95%
With Property Taxes and A07511 Tax Exemption Policy; Without Insurance:										
NYC:	12.92%	12.82%	12.73%	12.65%	12.57%	12.50%	12.44%	12.38%	12.32%	12.27%
With Property Taxes (no exemptions); Without Insurance:										
non-NYC:	13.47%	13.33%	13.21%	13.09%	12.99%	12.89%	12.80%	12.72%	12.65%	12.58%
NYC:	16.53%	16.38%	16.25%	16.13%	16.02%	15.92%	15.82%	15.74%	15.66%	15.58%
400 bp higher on nominal debt and equity cost:										
Without Property Taxes and Insurance:										
non-NYC:	13.41%	13.28%	13.17%	13.06%	12.97%	12.88%	12.80%	12.73%	12.67%	12.61%
NYC:	13.93%	13.79%	13.67%	13.56%	13.45%	13.36%	13.27%	13.20%	13.12%	13.06%
With Property Taxes and A07511 Tax Exemption Policy; Without Insurance:										
NYC:	14.81%	14.71%	14.62%	14.54%	14.46%	14.39%	14.33%	14.27%	14.22%	14.17%
With Property Taxes (no exemptions); Without Insurance:										
non-NYC:	15.41%	15.28%	15.17%	15.06%	14.97%	14.88%	14.80%	14.73%	14.67%	14.61%
NYC:	18.56%	18.42%	18.30%	18.19%	18.08%	17.99%	17.90%	17.83%	17.75%	17.69%

Based on 20-Year MACRS Depreciation (Combined Cycle)

Debt Amortization Years * =	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25
Base Case:																
Without Property Taxes and Insurance:																
non-NYC:	10.64%	10.56%	10.49%	10.42%	10.35%	10.28%	10.22%	10.15%	10.09%	10.03%	9.97%	9.91%	9.86%	9.80%	9.75%	9.70%
NYC:	11.21%	11.13%	11.04%	10.96%	10.88%	10.81%	10.73%	10.66%	10.59%	10.52%	10.45%	10.38%	10.32%	10.26%	10.20%	10.14%
With Property Taxes and A07511 Tax Exemption Policy; Without Insurance:																
NYC:	12.60%	12.51%	12.43%	12.34%	12.26%	12.19%	12.11%	12.04%	11.97%	11.90%	11.83%	11.76%	11.70%	11.64%	11.58%	11.52%
With Property Taxes (no exemptions); Without Insurance:																
NYC:	15.84%	15.76%	15.67%	15.59%	15.51%	15.44%	15.36%	15.29%	15.22%	15.15%	15.08%	15.01%	14.95%	14.89%	14.83%	14.77%
200 bp higher on nominal debt and equity cost:																
Without Property Taxes and Insurance:																
non-NYC:	12.75%	12.66%	12.57%	12.48%	12.40%	12.32%	12.24%	12.16%	12.09%	12.02%	11.95%	11.89%	11.82%	11.76%	11.70%	11.65%
NYC:	13.46%	13.36%	13.25%	13.15%	13.06%	12.97%	12.87%	12.79%	12.70%	12.62%	12.54%	12.47%	12.39%	12.32%	12.25%	12.19%
With Property Taxes and A07511 Tax Exemption Policy; Without Insurance:																
NYC:	14.65%	14.54%	14.44%	14.34%	14.24%	14.15%	14.06%	13.97%	13.89%	13.81%	13.73%	13.65%	13.58%	13.51%	13.44%	13.37%
With Property Taxes (no exemptions); Without Insurance:																
NYC:	18.09%	17.99%	17.88%	17.78%	17.69%	17.59%	17.50%	17.42%	17.33%	17.25%	17.17%	17.10%	17.02%	16.95%	16.88%	16.82%
400 bp higher on nominal debt and equity cost:																
Without Property Taxes and Insurance:																
non-NYC:	14.96%	14.85%	14.74%	14.64%	14.54%	14.45%	14.36%	14.27%	14.19%	14.11%	14.04%	13.97%	13.90%	13.83%	13.77%	13.71%
NYC:	15.81%	15.69%	15.56%	15.45%	15.33%	15.22%	15.12%	15.02%	14.92%	14.83%	14.74%	14.66%	14.58%	14.50%	14.43%	14.36%
With Property Taxes and A07511 Tax Exemption Policy; Without Insurance:																
NYC:	16.82%	16.70%	16.57%	16.46%	16.34%	16.23%	16.13%	16.03%	15.93%	15.84%	15.75%	15.67%	15.59%	15.51%	15.44%	15.37%
With Property Taxes (no exemptions); Without Insurance:																
NYC:	20.44%	20.32%	20.19%	20.08%	19.96%	19.85%	19.75%	19.65%	19.55%	19.46%	19.37%	19.29%	19.21%	19.13%	19.06%	18.99%

* In all cases the fixed charge and equity amortization period is 30 years.

Debt Amortization Years * =	26	27	28	29	30	31	32	33	34	35
Base Case:										
Without Property Taxes and Insurance:										
non-NYC:	9.65%	9.60%	9.55%	9.51%	9.46%	9.36%	9.27%	9.18%	9.10%	9.03%
NYC:	10.08%	10.02%	9.97%	9.92%	9.87%	9.75%	9.65%	9.55%	9.46%	9.37%
With Property Taxes and A07511 Tax Exemption Policy; Without Insurance:										
NYC:	11.46%	11.41%	11.35%	11.30%	11.25%	11.13%	11.03%	10.93%	10.84%	10.75%
With Property Taxes (no exemptions); Without Insurance:										
NYC:	14.71%	14.65%	14.60%	14.55%	14.49%	14.38%	14.28%	14.18%	14.09%	14.00%
200 bp higher on nominal debt and equity cost:										
Without Property Taxes and Insurance:										
non-NYC:	11.59%	11.54%	11.49%	11.44%	11.39%	11.30%	11.21%	11.12%	11.05%	10.98%
NYC:	12.12%	12.06%	12.00%	11.95%	11.89%	11.78%	11.68%	11.58%	11.49%	11.41%
With Property Taxes and A07511 Tax Exemption Policy; Without Insurance:										
NYC:	13.31%	13.25%	13.19%	13.13%	13.08%	12.96%	12.86%	12.76%	12.68%	12.59%
With Property Taxes (no exemptions); Without Insurance:										
NYC:	16.75%	16.69%	16.63%	16.58%	16.52%	16.41%	16.30%	16.21%	16.12%	16.04%
400 bp higher on nominal debt and equity cost:										
Without Property Taxes and Insurance:										
non-NYC:	13.65%	13.60%	13.55%	13.50%	13.45%	13.36%	13.28%	13.20%	13.13%	13.07%
NYC:	14.29%	14.22%	14.16%	14.10%	14.05%	13.94%	13.85%	13.76%	13.68%	13.60%
With Property Taxes and A07511 Tax Exemption Policy; Without Insurance:										
NYC:	15.30%	15.23%	15.17%	15.11%	15.06%	14.95%	14.85%	14.77%	14.68%	14.61%
With Property Taxes (no exemptions); Without Insurance:										
NYC:	18.92%	18.85%	18.79%	18.73%	18.68%	18.57%	18.47%	18.39%	18.30%	18.23%

* In all cases the fixed charge and equity amortization period is 30 years.

Debt Amortization Years =	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25
Base Case:																
Without Property Taxes and Insurance:																
non-NYC:	16.72%	15.74%	14.93%	14.23%	13.63%	13.11%	12.65%	12.24%	11.88%	11.55%	11.26%	10.99%	10.75%	10.53%	10.33%	10.15%
NYC:	17.39%	16.39%	15.56%	14.84%	14.23%	13.69%	13.22%	12.79%	12.41%	12.07%	11.76%	11.48%	11.22%	10.99%	10.78%	10.60%
With Property Taxes and A07511 Tax Exemption Policy; Without Insurance:																
NYC:	17.39%	16.39%	15.56%	14.84%	14.23%	13.69%	13.40%	13.13%	12.90%	12.68%	12.48%	12.30%	12.13%	11.98%	11.85%	11.72%
With Property Taxes (no exemptions); Without Insurance:																
non-NYC:	18.72%	17.74%	16.93%	16.23%	15.63%	15.11%	14.65%	14.24%	13.88%	13.55%	13.26%	12.99%	12.75%	12.53%	12.33%	12.15%
NYC:	22.02%	21.02%	20.19%	19.47%	18.86%	18.32%	17.84%	17.42%	17.04%	16.70%	16.39%	16.11%	15.85%	15.62%	15.41%	15.22%
200 bp higher on nominal debt and equity cost:																
Without Property Taxes and Insurance:																
non-NYC:	18.58%	17.60%	16.78%	16.08%	15.48%	14.96%	14.50%	14.10%	13.74%	13.41%	13.12%	12.86%	12.62%	12.41%	12.22%	12.05%
NYC:	19.40%	18.39%	17.55%	16.83%	16.21%	15.66%	15.19%	14.77%	14.39%	14.05%	13.74%	13.46%	13.21%	12.98%	12.78%	12.59%
With Property Taxes and A07511 Tax Exemption Policy; Without Insurance:																
NYC:	19.40%	18.39%	17.55%	16.83%	16.21%	15.66%	15.35%	15.07%	14.81%	14.58%	14.37%	14.17%	14.00%	13.84%	13.70%	13.57%
With Property Taxes (no exemptions); Without Insurance:																
non-NYC:	20.58%	19.60%	18.78%	18.08%	17.48%	16.96%	16.50%	16.10%	15.74%	15.41%	15.12%	14.86%	14.62%	14.41%	14.22%	14.05%
NYC:	24.03%	23.02%	22.18%	21.46%	20.84%	20.29%	19.82%	19.39%	19.02%	18.68%	18.37%	18.09%	17.84%	17.61%	17.41%	17.22%
400 bp higher on nominal debt and equity cost:																
Without Property Taxes and Insurance:																
non-NYC:	20.49%	19.51%	18.69%	17.99%	17.40%	16.88%	16.43%	16.03%	15.68%	15.36%	15.08%	14.83%	14.60%	14.40%	14.22%	14.05%
NYC:	21.45%	20.44%	19.59%	18.87%	18.25%	17.71%	17.24%	16.82%	16.45%	16.11%	15.81%	15.54%	15.29%	15.08%	14.88%	14.71%
With Property Taxes and A07511 Tax Exemption Policy; Without Insurance:																
NYC:	21.45%	20.44%	19.59%	18.87%	18.25%	17.71%	17.38%	17.08%	16.82%	16.58%	16.36%	16.16%	15.98%	15.82%	15.67%	15.55%
With Property Taxes (no exemptions); Without Insurance:																
non-NYC:	22.49%	21.51%	20.69%	19.99%	19.40%	18.88%	18.43%	18.03%	17.68%	17.36%	17.08%	16.83%	16.60%	16.40%	16.22%	16.05%
NYC:	26.08%	25.07%	24.22%	23.50%	22.88%	22.34%	21.87%	21.45%	21.08%	20.74%	20.44%	20.17%	19.92%	19.71%	19.51%	19.33%

Debt Amortization Years =	26	27	28	29	30	31	32	33	34	35
Base Case:										
Without Property Taxes and Insurance:										
non-NYC:	9.99%	9.84%	9.70%	9.58%	9.46%	9.36%	9.26%	9.17%	9.08%	9.00%
NYC:	10.42%	10.26%	10.12%	9.99%	9.87%	9.75%	9.65%	9.55%	9.46%	9.38%
With Property Taxes and A07511 Tax Exemption Policy; Without Insurance:										
NYC:	11.61%	11.51%	11.41%	11.33%	11.25%	11.17%	11.11%	11.04%	10.98%	10.93%
With Property Taxes (no exemptions); Without Insurance:										
non-NYC:	11.99%	11.84%	11.70%	11.58%	11.46%	11.36%	11.26%	11.17%	11.08%	11.00%
NYC:	15.05%	14.89%	14.75%	14.62%	14.49%	14.38%	14.28%	14.18%	14.09%	14.01%
200 bp higher on nominal debt and equity cost:										
Without Property Taxes and Insurance:										
non-NYC:	11.89%	11.75%	11.62%	11.50%	11.39%	11.29%	11.20%	11.12%	11.04%	10.97%
NYC:	12.42%	12.27%	12.13%	12.01%	11.89%	11.78%	11.69%	11.60%	11.51%	11.44%
With Property Taxes and A07511 Tax Exemption Policy; Without Insurance:										
NYC:	13.45%	13.34%	13.25%	13.16%	13.08%	13.00%	12.93%	12.87%	12.81%	12.75%
With Property Taxes (no exemptions); Without Insurance:										
non-NYC:	13.89%	13.75%	13.62%	13.50%	13.39%	13.29%	13.20%	13.12%	13.04%	12.97%
NYC:	17.05%	16.90%	16.76%	16.64%	16.52%	16.41%	16.32%	16.23%	16.14%	16.07%
400 bp higher on nominal debt and equity cost:										
Without Property Taxes and Insurance:										
non-NYC:	13.91%	13.78%	13.66%	13.55%	13.45%	13.36%	13.28%	13.20%	13.14%	13.07%
NYC:	14.55%	14.40%	14.27%	14.16%	14.05%	13.95%	13.86%	13.78%	13.71%	13.64%
With Property Taxes and A07511 Tax Exemption Policy; Without Insurance:										
NYC:	15.43%	15.32%	15.23%	15.14%	15.06%	14.99%	14.92%	14.86%	14.80%	14.75%
With Property Taxes (no exemptions); Without Insurance:										
non-NYC:	15.91%	15.78%	15.66%	15.55%	15.45%	15.36%	15.28%	15.20%	15.14%	15.07%
NYC:	19.18%	19.03%	18.90%	18.79%	18.68%	18.58%	18.49%	18.41%	18.33%	18.27%

C. Appendix 3 – STATA Output

```
. regress llbmp m#z c.load#z c.aggload#c.load#z c.aggload#region c.aggload2#region
c.aggload3#region c.lgasp##c.lgasp c.lgasp#m#h c.ae2#region c.bay#region h#m i.dow i.z c.tmax
c.tmin
```

Source	SS	df	MS	Number of obs = 289311			
-----+-----				F(746,288564) = 2664.01			
Model	34827.7175	746	46.6859484	Prob > F = 0.0000			
Residual	5056.99178288564		.01752468	R-squared = 0.8732			
-----+-----				Adj R-squared = 0.8729			
Total	39884.7093289310		.137861496	Root MSE = .13238			

llbmp	Coef.	Std. Err.	t	P> t	[95% Conf. Interval]		
-----+-----							
m#z							
2 1	-.1278864	.0278731	-4.59	0.000	-.182517	-.0732558	
2 2	-.1235827	.0277734	-4.45	0.000	-.1780177	-.0691476	
2 3	-.1173977	.0278731	-4.21	0.000	-.1720281	-.0627673	
2 4	-.1202712	.0277733	-4.33	0.000	-.1747061	-.0658362	
2 5	-.1187154	.0278753	-4.26	0.000	-.1733503	-.0640805	
2 6	-.1341608	.0278666	-4.81	0.000	-.1887785	-.0795431	
2 7	-.1260864	.027773	-4.54	0.000	-.1805207	-.0716521	
2 8	-.1174896	.027877	-4.21	0.000	-.1721277	-.0628516	
2 9	-.1027832	.0278609	-3.69	0.000	-.1573899	-.0481765	
2 10	-.1313398	.0277731	-4.73	0.000	-.1857744	-.0769052	
2 11	-.0781192	.0277733	-2.81	0.005	-.1325541	-.0236844	
3 1	-.2771726	.0281676	-9.84	0.000	-.3323803	-.2219649	

3	2		-.2044968	.0280246	-7.30	0.000	-.2594241	-.1495694
3	3		-.2395383	.0281686	-8.50	0.000	-.294748	-.1843286
3	4		-.2119301	.0280211	-7.56	0.000	-.2668507	-.1570096
3	5		-.249627	.0281702	-8.86	0.000	-.3048399	-.1944141
3	6		-.2788275	.0281046	-9.92	0.000	-.3339116	-.2237433
3	7		-.2216734	.0280305	-7.91	0.000	-.2766125	-.1667343
3	8		-.2424251	.0281791	-8.60	0.000	-.2976553	-.1871948
3	9		-.1989833	.0281044	-7.08	0.000	-.2540671	-.1438995
3	10		-.2306142	.0280217	-8.23	0.000	-.285536	-.1756924
3	11		-.1762376	.0280199	-6.29	0.000	-.2311557	-.1213194
4	1		-.4730498	.0276096	-17.13	0.000	-.5271639	-.4189356
4	2		-.3286656	.0275036	-11.95	0.000	-.3825719	-.2747592
4	3		-.420379	.027603	-15.23	0.000	-.4744801	-.366278
4	4		-.335636	.0274883	-12.21	0.000	-.3895122	-.2817597
4	5		-.4289084	.0276107	-15.53	0.000	-.4830247	-.3747921
4	6		-.4658962	.0275604	-16.90	0.000	-.5199138	-.4118786
4	7		-.3676361	.0275122	-13.36	0.000	-.4215593	-.3137129
4	8		-.420614	.0276196	-15.23	0.000	-.4747477	-.3664804
4	9		-.3399309	.027577	-12.33	0.000	-.3939809	-.2858808
4	10		-.3864266	.0274892	-14.06	0.000	-.4403047	-.3325485
4	11		-.3053048	.0274848	-11.11	0.000	-.3591742	-.2514355
5	1		-.5905224	.0308769	-19.13	0.000	-.6510403	-.5300046
5	2		-.4530745	.0308122	-14.70	0.000	-.5134656	-.3926835
5	3		-.5392904	.0308749	-17.47	0.000	-.5998044	-.4787764
5	4		-.4649595	.030777	-15.11	0.000	-.5252816	-.4046374
5	5		-.5466879	.0308721	-17.71	0.000	-.6071963	-.4861795
5	6		-.6087703	.0308337	-19.74	0.000	-.6692036	-.548337
5	7		-.4987613	.0308342	-16.18	0.000	-.5591955	-.4383271
5	8		-.5456672	.0308907	-17.66	0.000	-.6062121	-.4851223

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5	9		-.540018	.0308578	-17.50	0.000	-.6004985	-.4795375
5	10		-.5198989	.0307779	-16.89	0.000	-.5802227	-.4595752
5	11		-.443466	.0307795	-14.41	0.000	-.503793	-.383139
6	1		-.2254995	.0297631	-7.58	0.000	-.2838343	-.1671647
6	2		-.0513456	.029682	-1.73	0.084	-.1095215	.0068303
6	3		-.1340842	.0297301	-4.51	0.000	-.1923543	-.075814
6	4		-.0637555	.0296255	-2.15	0.031	-.1218207	-.0056903
6	5		-.1482458	.0297252	-4.99	0.000	-.2065064	-.0899851
6	6		-.2968336	.0297357	-9.98	0.000	-.3551147	-.2385526
6	7		-.0926389	.0297164	-3.12	0.002	-.1508822	-.0343956
6	8		-.1437793	.0297377	-4.83	0.000	-.2020643	-.0854943
6	9		-.1481113	.02976	-4.98	0.000	-.2064401	-.0897825
6	10		-.0892607	.0296178	-3.01	0.003	-.1473108	-.0312105
6	11		-.0365753	.0296331	-1.23	0.217	-.0946555	.0215048
7	1		-.1003702	.0371432	-2.70	0.007	-.1731698	-.0275706
7	2		.1355881	.0370533	3.66	0.000	.0629647	.2082115
7	3		-.0449218	.0371067	-1.21	0.226	-.1176498	.0278063
7	4		.1208483	.0369815	3.27	0.001	.0483657	.193331
7	5		-.0484245	.0371064	-1.31	0.192	-.1211521	.0243031
7	6		-.1444049	.0371153	-3.89	0.000	-.2171498	-.07166
7	7		.0760453	.0370704	2.05	0.040	.0033884	.1487023
7	8		-.0510711	.0371249	-1.38	0.169	-.1238349	.0216927
7	9		-.0402606	.0371435	-1.08	0.278	-.1130608	.0325396
7	10		.105481	.0369535	2.85	0.004	.0330532	.1779088
7	11		.1540352	.0369874	4.16	0.000	.0815408	.2265295
8	1		-.5661445	.0398727	-14.20	0.000	-.6442938	-.4879951
8	2		-.3482029	.0398338	-8.74	0.000	-.426276	-.2701298
8	3		-.4999774	.0398499	-12.55	0.000	-.578082	-.4218728
8	4		-.3601617	.0397671	-9.06	0.000	-.4381042	-.2822192

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8	5		-.5066481	.0398477	-12.71	0.000	-.5847485	-.4285478
8	6		-.6680801	.0398538	-16.76	0.000	-.7461924	-.5899678
8	7		-.399616	.0398333	-10.03	0.000	-.4776881	-.321544
8	8		-.5056212	.0398706	-12.68	0.000	-.5837665	-.4274759
8	9		-.5011625	.0398686	-12.57	0.000	-.5793038	-.4230211
8	10		-.3733594	.0397451	-9.39	0.000	-.4512586	-.2954601
8	11		-.3274874	.0397807	-8.23	0.000	-.4054564	-.2495184
9	1		-.2823118	.0459887	-6.14	0.000	-.3724483	-.1921753
9	2		-.1014024	.0459035	-2.21	0.027	-.1913719	-.011433
9	3		-.1888949	.0459616	-4.11	0.000	-.2789784	-.0988114
9	4		-.111857	.045858	-2.44	0.015	-.2017374	-.0219767
9	5		-.1961019	.0459617	-4.27	0.000	-.2861856	-.1060182
9	6		-.3420258	.0459191	-7.45	0.000	-.432026	-.2520256
9	7		-.1382944	.0459224	-3.01	0.003	-.2283011	-.0482877
9	8		-.1944944	.0459749	-4.23	0.000	-.284604	-.1043848
9	9		-.2081239	.0459341	-4.53	0.000	-.2981534	-.1180943
9	10		-.1266442	.0458463	-2.76	0.006	-.2165015	-.0367868
9	11		-.0857109	.0458683	-1.87	0.062	-.1756115	.0041896
10	1		.042693	.0947918	0.45	0.652	-.1430962	.2284822
10	2		.1887438	.0946132	1.99	0.046	.0033044	.3741831
10	3		.1352583	.0947694	1.43	0.154	-.0504871	.3210037
10	4		.1843956	.0945976	1.95	0.051	-.0010132	.3698043
10	5		.1291919	.0947666	1.36	0.173	-.0565479	.3149318
10	6		.0417941	.0946177	0.44	0.659	-.143654	.2272423
10	7		.150753	.0946253	1.59	0.111	-.03471	.336216
10	8		.1324771	.0947657	1.40	0.162	-.0532609	.3182152
10	9		.1185748	.0945808	1.25	0.210	-.0668008	.3039505
10	10		.1177592	.0945975	1.24	0.213	-.0676492	.3031676
10	11		.2150093	.0945988	2.27	0.023	.0295983	.4004204

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11	1		-.1662241	.0504462	-3.30	0.001	-.2650973	-.0673509
11	2		.0074056	.0502732	0.15	0.883	-.0911285	.1059397
11	3		-.1192118	.0504466	-2.36	0.018	-.2180857	-.0203378
11	4		.0061985	.0502621	0.12	0.902	-.0923138	.1047108
11	5		-.119764	.0504452	-2.37	0.018	-.2186352	-.0208928
11	6		-.1451758	.0503144	-2.89	0.004	-.2437906	-.046561
11	7		-.0171429	.050287	-0.34	0.733	-.115704	.0814183
11	8		-.1193267	.0504487	-2.37	0.018	-.2182049	-.0204486
11	9		-.0925219	.0503045	-1.84	0.066	-.1911173	.0060735
11	10		.0137576	.0502637	0.27	0.784	-.084758	.1122731
11	11		-.0297474	.0502635	-0.59	0.554	-.1282624	.0687676
12	1		.01161	.028111	0.41	0.680	-.0434868	.0667069
12	2		.0637569	.0280412	2.27	0.023	.0087969	.1187169
12	3		.0252231	.0281106	0.90	0.370	-.029873	.0803191
12	4		.0659499	.0280412	2.35	0.019	.0109899	.1209099
12	5		.0275946	.0281107	0.98	0.326	-.0275017	.0826909
12	6		.0392118	.0281173	1.39	0.163	-.0158973	.0943209
12	7		.0596911	.0280468	2.13	0.033	.0047201	.114662
12	8		.0258041	.0281109	0.92	0.359	-.0292926	.0809007
12	9		.0302386	.0281101	1.08	0.282	-.0248564	.0853336
12	10		.078426	.0280409	2.80	0.005	.0234666	.1333855
12	11		.0448862	.0280421	1.60	0.109	-.0100756	.099848
z#c.load								
	1		.0001409	.0000206	6.84	0.000	.0001005	.0001813
	2		.0002484	.0000177	14.05	0.000	.0002138	.0002831
	3		-.0005477	.0000595	-9.20	0.000	-.0006643	-.0004311
	4		.0003525	.000025	14.11	0.000	.0003036	.0004015
	5		-.0002957	.0000413	-7.17	0.000	-.0003766	-.0002149

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6		-.0000814	.0000296	-2.75	0.006	-.0001395	-.0000233
7		-.0001249	.0000277	-4.50	0.000	-.0001792	-.0000705
8		-.0006345	.0001112	-5.71	0.000	-.0008525	-.0004165
9		3.21e-06	.000017	0.19	0.851	-.0000302	.0000366
10		-.0002213	.0000266	-8.31	0.000	-.0002735	-.0001691
11		.000013	.000017	0.77	0.443	-.0000202	.0000462

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z#c.aggload#c.load |

1		5.08e-09	6.90e-10	7.36	0.000	3.73e-09	6.43e-09
2		-1.24e-09	5.63e-10	-2.21	0.027	-2.34e-09	-1.39e-10
3		2.16e-08	2.71e-09	7.99	0.000	1.63e-08	2.70e-08
4		-2.49e-09	8.31e-10	-3.00	0.003	-4.12e-09	-8.60e-10
5		1.14e-08	1.77e-09	6.46	0.000	7.97e-09	1.49e-08
6		1.18e-08	1.37e-09	8.61	0.000	9.14e-09	1.45e-08
7		1.28e-08	1.03e-09	12.44	0.000	1.08e-08	1.48e-08
8		3.26e-08	5.51e-09	5.92	0.000	2.18e-08	4.34e-08
9		-2.09e-10	8.22e-10	-0.25	0.799	-1.82e-09	1.40e-09
10		1.70e-08	1.34e-09	12.70	0.000	1.44e-08	1.97e-08
11		2.78e-09	5.58e-10	4.98	0.000	1.68e-09	3.87e-09

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region#c.aggload |

0		.0004456	5.33e-06	83.62	0.000	.0004351	.000456
1		.0004509	.0000136	33.18	0.000	.0004242	.0004775
2		.0003964	.0000118	33.45	0.000	.0003732	.0004197
3		.0005067	7.01e-06	72.30	0.000	.0004929	.0005204

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region#c.aggload2 |

0		-.0001936	2.55e-06	-75.87	0.000	-.0001986	-.0001886
1		-.0001756	6.54e-06	-26.86	0.000	-.0001885	-.0001628

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2		-.0001632	5.59e-06	-29.21	0.000	-.0001742	-.0001523
3		-.0002119	3.35e-06	-63.21	0.000	-.0002185	-.0002054
region#c.aggload3							
0		.00003	3.93e-07	76.38	0.000	.0000292	.0000307
1		.0000273	8.55e-07	31.91	0.000	.0000256	.000029
2		.0000236	8.57e-07	27.56	0.000	.0000219	.0000253
3		.0000329	5.25e-07	62.64	0.000	.0000319	.0000339
lgasp		.2911886	.0145978	19.95	0.000	.2625773	.3198
c.lgasp#c.lgasp		.0287196	.0027259	10.54	0.000	.0233768	.0340623
m#h#c.lgasp							
1 1		-.0338909	.0144128	-2.35	0.019	-.0621396	-.0056422
1 2		-.0167659	.0144133	-1.16	0.245	-.0450155	.0114838
1 3		-.0144938	.0144136	-1.01	0.315	-.0427439	.0137564
1 4		.0072695	.0144134	0.50	0.614	-.0209803	.0355193
1 5		.0167364	.0144128	1.16	0.246	-.0115123	.0449851
1 6		.0737075	.0144136	5.11	0.000	.0454573	.1019577
1 7		.113213	.0144151	7.85	0.000	.0849597	.1414662
1 8		.1112634	.014416	7.72	0.000	.0830084	.1395183
1 9		.1085088	.014417	7.53	0.000	.080252	.1367657
1 10		.1027154	.0144176	7.12	0.000	.0744574	.1309735
1 11		.0870859	.0144176	6.04	0.000	.0588277	.1153441
1 12		.056423	.0144174	3.91	0.000	.0281652	.0846808
1 13		.0228688	.0144172	1.59	0.113	-.0053885	.0511261
1 14		.0026862	.0144169	0.19	0.852	-.0255705	.030943
1 15		.0305888	.014417	2.12	0.034	.002332	.0588456

1	16		.0638223	.0144184	4.43	0.000	.0355627	.0920819
1	17		.0520085	.0144219	3.61	0.000	.023742	.0802749
1	18		.125439	.0144224	8.70	0.000	.0971715	.1537064
1	19		.1087397	.0144214	7.54	0.000	.0804743	.1370052
1	20		.102327	.0144198	7.10	0.000	.0740646	.1305894
1	21		.0571249	.0144175	3.96	0.000	.028867	.0853828
1	22		.0339097	.0144149	2.35	0.019	.0056568	.0621625
1	23		.034805	.0144131	2.41	0.016	.0065556	.0630543
2	0		-.0490285	.0154785	-3.17	0.002	-.0793659	-.018691
2	1		-.0781891	.0154788	-5.05	0.000	-.1085272	-.047851
2	2		-.066421	.0154792	-4.29	0.000	-.0967598	-.0360823
2	3		-.041155	.0154793	-2.66	0.008	-.0714941	-.0108159
2	4		-.0327176	.0154792	-2.11	0.035	-.0630563	-.0023789
2	5		-.0768381	.0154787	-4.96	0.000	-.107176	-.0465003
2	6		.0818977	.0154797	5.29	0.000	.0515579	.1122374
2	7		.0806197	.0154811	5.21	0.000	.0502771	.1109623
2	8		.0313661	.0154822	2.03	0.043	.0010214	.0617108
2	9		.0500398	.0154831	3.23	0.001	.0196933	.0803863
2	10		.0372893	.0154837	2.41	0.016	.0069417	.0676369
2	11		.0041616	.0154838	0.27	0.788	-.0261862	.0345094
2	12		-.0274621	.0154835	-1.77	0.076	-.0578092	.0028851
2	13		-.054075	.0154831	-3.49	0.000	-.0844215	-.0237286
2	14		-.0668316	.0154827	-4.32	0.000	-.0971773	-.0364859
2	15		-.0720429	.0154826	-4.65	0.000	-.1023883	-.0416975
2	16		-.0235299	.0154833	-1.52	0.129	-.0538767	.0068169
2	17		-.0148695	.0154857	-0.96	0.337	-.045221	.015482
2	18		.0321471	.015487	2.08	0.038	.0017929	.0625012
2	19		.0320364	.0154861	2.07	0.039	.001684	.0623888
2	20		.0246852	.0154847	1.59	0.111	-.0056644	.0550349

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2	21		-.031018	.0154827	-2.00	0.045	-.0613635	-.0006724
2	22		-.0395466	.0154806	-2.55	0.011	-.0698881	-.0092051
2	23		.0008754	.0154791	0.06	0.955	-.0294631	.0312139
3	0		.1441427	.017192	8.38	0.000	.110447	.1778385
3	1		.1679871	.0171926	9.77	0.000	.13429	.2016842
3	2		.2062674	.0173073	11.92	0.000	.1723456	.2401892
3	3		.2424254	.0171942	14.10	0.000	.2087252	.2761255
3	4		.2182888	.0171939	12.70	0.000	.1845891	.2519884
3	5		.158067	.0171925	9.19	0.000	.1243702	.1917639
3	6		.1051243	.0171915	6.11	0.000	.0714294	.1388191
3	7		.1192981	.0171923	6.94	0.000	.0856016	.1529945
3	8		.0002733	.0171935	0.02	0.987	-.0334254	.0339721
3	9		.0177749	.0171944	1.03	0.301	-.0159256	.0514754
3	10		-.0035809	.017195	-0.21	0.835	-.0372826	.0301208
3	11		-.0245178	.0171953	-1.43	0.154	-.05822	.0091845
3	12		-.0328073	.0171953	-1.91	0.056	-.0665097	.000895
3	13		-.025345	.0171953	-1.47	0.140	-.0590474	.0083573
3	14		-.0118961	.0171952	-0.69	0.489	-.0455982	.0218061
3	15		-.0127307	.017195	-0.74	0.459	-.0464324	.0209709
3	16		-.0113787	.0171949	-0.66	0.508	-.0450802	.0223229
3	17		.0013771	.0171951	0.08	0.936	-.0323249	.035079
3	18		.0562366	.0171962	3.27	0.001	.0225325	.0899408
3	19		-.219456	.0171964	-12.76	0.000	-.2531604	-.1857516
3	20		-.1001765	.0171957	-5.83	0.000	-.1338796	-.0664734
3	21		-.0241111	.0171944	-1.40	0.161	-.0578116	.0095894
3	22		.0136306	.017193	0.79	0.428	-.0200671	.0473283
3	23		.115381	.0171921	6.71	0.000	.0816851	.149077
4	0		.3798409	.0172992	21.96	0.000	.345935	.4137469
4	1		.4123558	.0173011	23.83	0.000	.3784461	.4462655

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4	2		.4814661	.0173022	27.83	0.000	.4475543	.515378
4	3		.5250074	.0173033	30.34	0.000	.4910933	.5589215
4	4		.5290725	.0173036	30.58	0.000	.4951579	.5629872
4	5		.450528	.0173017	26.04	0.000	.4166171	.4844389
4	6		.3452609	.0172978	19.96	0.000	.3113578	.3791641
4	7		.2294244	.0172955	13.26	0.000	.1955257	.2633232
4	8		.1404569	.0172946	8.12	0.000	.1065601	.1743538
4	9		.1201145	.0172941	6.95	0.000	.0862184	.1540105
4	10		.1182987	.0172939	6.84	0.000	.0844032	.1521942
4	11		.1316154	.017294	7.61	0.000	.0977197	.1655111
4	12		.1147892	.0172942	6.64	0.000	.080893	.1486854
4	13		.1646302	.0172945	9.52	0.000	.1307335	.1985269
4	14		.1695786	.0172948	9.81	0.000	.1356813	.203476
4	15		.1816908	.017295	10.51	0.000	.147793	.2155885
4	16		.1897187	.017295	10.97	0.000	.155821	.2236164
4	17		.1841082	.0172951	10.65	0.000	.1502102	.2180061
4	18		.1903195	.0172954	11.00	0.000	.1564211	.2242179
4	19		.0743136	.0172951	4.30	0.000	.0404156	.1082116
4	20		.0062931	.0172953	0.36	0.716	-.0276052	.0401914
4	21		.1219359	.0172956	7.05	0.000	.088037	.1558347
4	22		.2154546	.0172962	12.46	0.000	.1815546	.2493545
4	23		.3307874	.0172978	19.12	0.000	.2968843	.3646905
5	0		.4015469	.0195491	20.54	0.000	.3632312	.4398627
5	1		.4328503	.0195494	22.14	0.000	.394534	.4711666
5	2		.5385889	.0195499	27.55	0.000	.5002715	.5769062
5	3		.6117636	.0195507	31.29	0.000	.5734447	.6500825
5	4		.6161703	.0195514	31.52	0.000	.5778501	.6544905
5	5		.5259361	.019552	26.90	0.000	.4876146	.5642575
5	6		.4559894	.0195528	23.32	0.000	.4176665	.4943122

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5	7		.3443269	.0195515	17.61	0.000	.3060065	.3826473
5	8		.3192561	.0195505	16.33	0.000	.2809377	.3575746
5	9		.2773129	.01955	14.18	0.000	.2389954	.3156303
5	10		.2261285	.0195497	11.57	0.000	.1878116	.2644455
5	11		.2003482	.0195497	10.25	0.000	.1620313	.2386651
5	12		.1899555	.0195497	9.72	0.000	.1516386	.2282724
5	13		.1911019	.0195499	9.78	0.000	.1527847	.2294191
5	14		.1901457	.0195501	9.73	0.000	.1518281	.2284633
5	15		.1883303	.01955	9.63	0.000	.1500128	.2266477
5	16		.1912135	.01955	9.78	0.000	.152896	.229531
5	17		.1850356	.0195499	9.46	0.000	.1467184	.2233528
5	18		.1948226	.0195496	9.97	0.000	.1565059	.2331392
5	19		.1909347	.0195492	9.77	0.000	.1526187	.2292507
5	20		.2215424	.0195487	11.33	0.000	.1832275	.2598573
5	21		.2346399	.0195487	12.00	0.000	.1963251	.2729548
5	22		.3315181	.0195484	16.96	0.000	.2932038	.3698323
5	23		.4313387	.0195482	22.07	0.000	.3930247	.4696527
6	0		.1333824	.0179137	7.45	0.000	.0982721	.1684928
6	1		.1272667	.0179133	7.10	0.000	.0921572	.1623761
6	2		.1967507	.0179136	10.98	0.000	.1616405	.2318609
6	3		.2381493	.0179137	13.29	0.000	.2030389	.2732596
6	4		.2625558	.0179132	14.66	0.000	.2274464	.2976652
6	5		.2989517	.0179122	16.69	0.000	.2638443	.3340591
6	6		.1845158	.0179121	10.30	0.000	.1494086	.2196229
6	7		.1186137	.0179146	6.62	0.000	.0835016	.1537259
6	8		.0790817	.0179185	4.41	0.000	.0439619	.1142015
6	9		.0255368	.0179224	1.42	0.154	-.0095906	.0606642
6	10		-.0353626	.0179263	-1.97	0.049	-.0704976	-.0002277
6	11		-.0611212	.0179295	-3.41	0.001	-.0962625	-.02598

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6	12		-.0759704	.0179322	-4.24	0.000	-.111117	-.0408238
6	13		-.0896295	.0179336	-5.00	0.000	-.1247789	-.0544801
6	14		-.0823187	.0179357	-4.59	0.000	-.1174721	-.0471653
6	15		-.0857169	.0179374	-4.78	0.000	-.1208736	-.0505602
6	16		-.0941129	.0179387	-5.25	0.000	-.1292722	-.0589536
6	17		-.0796495	.0179374	-4.44	0.000	-.1148063	-.0444928
6	18		-.0383507	.017934	-2.14	0.032	-.0735009	-.0032005
6	19		-.0190383	.0179299	-1.06	0.288	-.0541805	.0161039
6	20		-.0195228	.0179276	-1.09	0.276	-.0546603	.0156147
6	21		.0063142	.0179261	0.35	0.725	-.0288205	.0414489
6	22		.0275853	.0179201	1.54	0.124	-.0075377	.0627082
6	23		.1241893	.0179144	6.93	0.000	.0890777	.159301
7	0		.0474878	.0225751	2.10	0.035	.0032411	.0917344
7	1		.0460531	.0225744	2.04	0.041	.001808	.0902982
7	2		.115546	.0225736	5.12	0.000	.0713024	.1597895
7	3		.1238413	.022573	5.49	0.000	.0795988	.1680839
7	4		.1433614	.0225728	6.35	0.000	.0991194	.1876034
7	5		.1774687	.0225732	7.86	0.000	.1332259	.2217114
7	6		.1535149	.0225733	6.80	0.000	.1092718	.1977579
7	7		.1317202	.0225744	5.83	0.000	.087475	.1759654
7	8		.0981352	.0225761	4.35	0.000	.0538866	.1423837
7	9		.0429286	.0225784	1.90	0.057	-.0013245	.0871817
7	10		-.0513288	.0225825	-2.27	0.023	-.0955899	-.0070678
7	11		-.0998874	.0225859	-4.42	0.000	-.1441551	-.0556197
7	12		-.1098597	.0225874	-4.86	0.000	-.1541303	-.0655892
7	13		-.1205654	.0225898	-5.34	0.000	-.1648409	-.07629
7	14		-.1287095	.0225931	-5.70	0.000	-.1729914	-.0844277
7	15		-.16305	.0225941	-7.22	0.000	-.2073337	-.1187663
7	16		-.181173	.0225942	-8.02	0.000	-.225457	-.136889

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7	17		-.1622181	.0225925	-7.18	0.000	-.2064988	-.1179374
7	18		-.0994218	.0225894	-4.40	0.000	-.1436963	-.0551472
7	19		-.0932503	.0225856	-4.13	0.000	-.1375174	-.0489831
7	20		-.0600701	.0225846	-2.66	0.008	-.1043353	-.0158048
7	21		-.074562	.0225827	-3.30	0.001	-.1188234	-.0303006
7	22		-.0186605	.0225775	-0.83	0.409	-.0629117	.0255907
7	23		.0534092	.0225743	2.37	0.018	.0091641	.0976542
8	0		.3536868	.0255994	13.82	0.000	.3035127	.4038609
8	1		.3932617	.0255984	15.36	0.000	.3430895	.443434
8	2		.4453003	.0255978	17.40	0.000	.3951293	.4954714
8	3		.5017359	.0255976	19.60	0.000	.4515653	.5519064
8	4		.478858	.0255975	18.71	0.000	.4286876	.5290284
8	5		.4869331	.0255982	19.02	0.000	.4367613	.537105
8	6		.4014146	.0255994	15.68	0.000	.3512405	.4515888
8	7		.3402048	.0256008	13.29	0.000	.290028	.3903816
8	8		.2832909	.0256011	11.07	0.000	.2331133	.3334684
8	9		.2120678	.0256012	8.28	0.000	.1618902	.2622454
8	10		.1998518	.0256017	7.81	0.000	.1496732	.2500303
8	11		.1487717	.025603	5.81	0.000	.0985905	.1989529
8	12		.1273093	.0256053	4.97	0.000	.0771236	.1774949
8	13		.1072861	.025607	4.19	0.000	.0570971	.1574752
8	14		.1007356	.0256079	3.93	0.000	.0505449	.1509262
8	15		.0638505	.0256089	2.49	0.013	.0136578	.1140432
8	16		.0504706	.0256095	1.97	0.049	.0002768	.1006645
8	17		.0982303	.0256092	3.84	0.000	.0480369	.1484236
8	18		.1636754	.0256068	6.39	0.000	.1134867	.2138641
8	19		.1736026	.025605	6.78	0.000	.1234174	.2237878
8	20		.1902503	.0256056	7.43	0.000	.140064	.2404366
8	21		.1968292	.0256035	7.69	0.000	.1466471	.2470114

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8	22		.2278512	.0256014	8.90	0.000	.1776731	.2780293
8	23		.377269	.0256002	14.74	0.000	.3270934	.4274446
9	0		.2635048	.031227	8.44	0.000	.2023007	.3247089
9	1		.3245889	.0312276	10.39	0.000	.2633837	.3857941
9	2		.3831941	.031228	12.27	0.000	.3219882	.4444001
9	3		.419381	.0312284	13.43	0.000	.3581742	.4805878
9	4		.4163484	.0312288	13.33	0.000	.3551407	.4775561
9	5		.3879648	.0312282	12.42	0.000	.3267584	.4491711
9	6		.3011371	.031228	9.64	0.000	.2399311	.3623431
9	7		.2180932	.0312285	6.98	0.000	.1568861	.2793003
9	8		.1202668	.0312291	3.85	0.000	.0590585	.181475
9	9		.0489447	.0312298	1.57	0.117	-.0122648	.1101541
9	10		.012453	.0312303	0.40	0.690	-.0487575	.0736634
9	11		-.0519757	.031267	-1.66	0.096	-.113258	.0093067
9	12		-.0869614	.0312313	-2.78	0.005	-.1481739	-.0257489
9	13		-.0815131	.0312317	-2.61	0.009	-.1427263	-.0202999
9	14		-.0912136	.0312318	-2.92	0.003	-.1524271	-.0300001
9	15		-.1290847	.0312321	-4.13	0.000	-.1902987	-.0678707
9	16		-.1461206	.0312322	-4.68	0.000	-.2073349	-.0849063
9	17		-.099296	.0312321	-3.18	0.001	-.1605101	-.038082
9	18		-.0504653	.0312323	-1.62	0.106	-.1116799	.0107492
9	19		-.1566174	.031234	-5.01	0.000	-.2178352	-.0953996
9	20		-.1175425	.031233	-3.76	0.000	-.1787584	-.0563266
9	21		.0100017	.0312308	0.32	0.749	-.0512098	.0712131
9	22		.0737956	.0312285	2.36	0.018	.0125885	.1350026
9	23		.2154687	.031227	6.90	0.000	.1542647	.2766727
10	0		-.0265741	.0677148	-0.39	0.695	-.1592932	.106145
10	1		-.2261469	.067742	-3.34	0.001	-.3589193	-.0933744
10	2		-.2793849	.0677698	-4.12	0.000	-.4122118	-.146558

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10	3		-.2045618	.0677853	-3.02	0.003	-.337419	-.0717046
10	4		-.2618428	.0677763	-3.86	0.000	-.3946826	-.1290031
10	5		-.2417316	.0677397	-3.57	0.000	-.3744995	-.1089637
10	6		-.255931	.0677232	-3.78	0.000	-.3886667	-.1231953
10	7		-.0519108	.0677257	-0.77	0.443	-.1846512	.0808297
10	8		.0435137	.06771	0.64	0.520	-.089196	.1762234
10	9		-.0611748	.0677069	-0.90	0.366	-.1938784	.0715287
10	10		-.1931733	.0677069	-2.85	0.004	-.3258768	-.0604697
10	11		-.2371784	.0677074	-3.50	0.000	-.3698829	-.1044738
10	12		-.2505039	.0677073	-3.70	0.000	-.3832084	-.1177995
10	13		-.2618906	.0677064	-3.87	0.000	-.3945932	-.1291879
10	14		-.2932188	.0677058	-4.33	0.000	-.4259203	-.1605172
10	15		-.3215211	.0677068	-4.75	0.000	-.4542245	-.1888176
10	16		-.3241939	.0677088	-4.79	0.000	-.4569013	-.1914866
10	17		-.2096704	.0677098	-3.10	0.002	-.3423798	-.076961
10	18		-.2511544	.0677125	-3.71	0.000	-.3838689	-.1184398
10	19		-.4137106	.0677129	-6.11	0.000	-.546426	-.2809953
10	20		-.2857519	.0677082	-4.22	0.000	-.418458	-.1530458
10	21		-.1508366	.0677013	-2.23	0.026	-.2835292	-.018144
10	22		-.1040337	.0676966	-1.54	0.124	-.2367172	.0286498
10	23		.0217919	.0677004	0.32	0.748	-.110899	.1544828
11	0		.2190217	.0337052	6.50	0.000	.1529604	.2850829
11	1		.2569264	.0336978	7.62	0.000	.1908796	.3229731
11	2		.2560953	.033724	7.59	0.000	.1899972	.3221934
11	3		.2751005	.0337279	8.16	0.000	.2089949	.3412062
11	4		.3038799	.0337222	9.01	0.000	.2377853	.3699745
11	5		.3122938	.0337074	9.26	0.000	.2462283	.3783594
11	6		-.0130283	.0337034	-0.39	0.699	-.0790861	.0530295
11	7		.0545265	.0337033	1.62	0.106	-.011531	.120584

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11	8		.0469353	.0337013	1.39	0.164	-.0191184	.112989
11	9		.0532837	.0337017	1.58	0.114	-.0127707	.119338
11	10		.0269137	.0337022	0.80	0.425	-.0391417	.0929691
11	11		.0429569	.0337025	1.27	0.202	-.0230991	.1090129
11	12		.0098259	.0337026	0.29	0.771	-.0562302	.075882
11	13		-.0368785	.0337026	-1.09	0.274	-.1029347	.0291776
11	14		-.0156225	.0337025	-0.46	0.643	-.0816784	.0504335
11	15		-.0291952	.0337029	-0.87	0.386	-.0952519	.0368614
11	16		-.0274584	.033705	-0.81	0.415	-.0935193	.0386024
11	17		-.0981667	.0337106	-2.91	0.004	-.1642386	-.0320948
11	18		.0056956	.0337116	0.17	0.866	-.0603782	.0717694
11	19		.0575879	.033709	1.71	0.088	-.0084808	.1236565
11	20		.0911383	.033706	2.70	0.007	.0250754	.1572012
11	21		.0369921	.0337027	1.10	0.272	-.0290643	.1030485
11	22		.0777326	.0337004	2.31	0.021	.0116807	.1437845
11	23		.1078932	.0337003	3.20	0.001	.0418415	.1739449
12	0		-.0428647	.0150756	-2.84	0.004	-.0724125	-.013317
12	1		-.0873049	.0150768	-5.79	0.000	-.1168551	-.0577548
12	2		-.0405226	.015078	-2.69	0.007	-.0700751	-.0109701
12	3		-.0267726	.0150785	-1.78	0.076	-.0563259	.0027808
12	4		-.0557474	.0150776	-3.70	0.000	-.0852991	-.0261957
12	5		-.0228698	.0150752	-1.52	0.129	-.0524168	.0066772
12	6		-.0527141	.0150751	-3.50	0.000	-.0822609	-.0231674
12	7		.0520241	.0150766	3.45	0.001	.0224745	.0815738
12	8		.0213192	.0150775	1.41	0.157	-.0082323	.0508707
12	9		.0140758	.0150784	0.93	0.351	-.0154774	.043629
12	10		.0110931	.0150789	0.74	0.462	-.0184611	.0406473
12	11		-.0178362	.0150789	-1.18	0.237	-.0473905	.011718
12	12		-.0210843	.0150786	-1.40	0.162	-.050638	.0084693

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12 13		-.0272362	.0150783	-1.81	0.071	-.0567893	.0023169
12 14		-.038184	.0150781	-2.53	0.011	-.0677367	-.0086313
12 15		-.031514	.0150782	-2.09	0.037	-.0610668	-.0019612
12 16		-.0653132	.0150798	-4.33	0.000	-.0948692	-.0357571
12 17		-.0968	.0150827	-6.42	0.000	-.1263617	-.0672384
12 18		-.0281043	.0150828	-1.86	0.062	-.0576661	.0014576
12 19		-.0230623	.0150821	-1.53	0.126	-.0526228	.0064983
12 20		.0134384	.0150813	0.89	0.373	-.0161206	.0429973
12 21		-.0139394	.0150799	-0.92	0.355	-.0434955	.0156168
12 22		-.043065	.0150774	-2.86	0.004	-.0726163	-.0135137
12 23		-.0332335	.0150752	-2.20	0.027	-.0627804	-.0036866
region#c.ae2							
0		-.0410888	.0010388	-39.56	0.000	-.0431248	-.0390529
1		-.1020949	.002025	-50.42	0.000	-.1060639	-.0981258
2		-.0716762	.0019897	-36.02	0.000	-.0755761	-.0677764
3		-.1253395	.0012027	-104.21	0.000	-.1276968	-.1229822
region#c.bay							
0		-.0508958	.0018284	-27.84	0.000	-.0544794	-.0473122
1		-.0618579	.0033063	-18.71	0.000	-.0683382	-.0553777
2		.0520808	.0033042	15.76	0.000	.0456047	.0585568
3		-.072894	.0019695	-37.01	0.000	-.0767541	-.0690339
h#m							
0 2		.1357577	.0277009	4.90	0.000	.0814647	.1900508
0 3		.0036582	.0276707	0.13	0.895	-.0505756	.0578919
0 4		-.030812	.0262546	-1.17	0.241	-.0822703	.0206462
0 5		.1055845	.0329577	3.20	0.001	.0409884	.1701806

0	6		.0471002	.0304252	1.55	0.122	-.0125323	.1067327
0	7		.0403339	.0434661	0.93	0.353	-.0448584	.1255262
0	8		.069813	.0479228	1.46	0.145	-.0241144	.1637404
0	9		.0007503	.0574478	0.01	0.990	-.1118458	.1133463
0	10		.1112277	.1296264	0.86	0.391	-.1428364	.3652919
0	11		-.1095671	.0651309	-1.68	0.093	-.2372219	.0180877
0	12		.0802594	.028377	2.83	0.005	.0246413	.1358775
1	1		.0463887	.0272343	1.70	0.089	-.0069897	.0997672
1	2		.1675377	.0277075	6.05	0.000	.1132317	.2218437
1	3		-.0512157	.0276814	-1.85	0.064	-.1054704	.003039
1	4		-.0738359	.0262607	-2.81	0.005	-.1253062	-.0223657
1	5		.0339315	.032964	1.03	0.303	-.0306771	.09854
1	6		.0006391	.0304347	0.02	0.983	-.0590122	.0602903
1	7		-.0050566	.0434721	-0.12	0.907	-.0902607	.0801475
1	8		-.0423185	.047926	-0.88	0.377	-.1362521	.0516151
1	9		-.1331578	.0574501	-2.32	0.020	-.2457584	-.0205571
1	10		.3569042	.1296557	2.75	0.006	.1027826	.6110257
1	11		-.164723	.0651038	-2.53	0.011	-.2923247	-.0371213
1	12		.1304811	.0283902	4.60	0.000	.0748371	.1861251
2	1		.0072455	.027238	0.27	0.790	-.0461401	.0606312
2	2		.1384282	.0277135	4.99	0.000	.0841105	.1927458
2	3		-.1250854	.0278497	-4.49	0.000	-.17967	-.0705008
2	4		-.1818227	.026267	-6.92	0.000	-.2333053	-.1303402
2	5		-.129006	.03297	-3.91	0.000	-.1936264	-.0643857
2	6		-.1378421	.0304445	-4.53	0.000	-.1975125	-.0781718
2	7		-.1359399	.0434771	-3.13	0.002	-.2211539	-.0507259
2	8		-.1611779	.047929	-3.36	0.001	-.2551174	-.0672383
2	9		-.2678244	.0574526	-4.66	0.000	-.3804299	-.1552189
2	10		.3974767	.1296848	3.06	0.002	.1432981	.6516553

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2	11		-.1792969	.0651597	-2.75	0.006	-.3070081	-.0515857
2	12		.0492136	.028402	1.73	0.083	-.0064535	.1048808
3	1		-.0001306	.02724	-0.00	0.996	-.0535202	.053259
3	2		.100092	.027716	3.61	0.000	.0457695	.1544146
3	3		-.1754256	.0276989	-6.33	0.000	-.2297146	-.1211365
3	4		-.2594014	.0262697	-9.87	0.000	-.3108893	-.2079135
3	5		-.2326717	.0329735	-7.06	0.000	-.2972988	-.1680446
3	6		-.2238798	.03045	-7.35	0.000	-.2835609	-.1641987
3	7		-.1597234	.0434803	-3.67	0.000	-.2449437	-.0745032
3	8		-.2620426	.0479311	-5.47	0.000	-.3559862	-.1680991
3	9		-.336725	.0574543	-5.86	0.000	-.4493339	-.2241161
3	10		.2762999	.1296998	2.13	0.033	.0220918	.530508
3	11		-.2080106	.0651666	-3.19	0.001	-.3357353	-.0802859
3	12		.0263836	.0284074	0.93	0.353	-.029294	.0820613
4	1		-.0480031	.0272383	-1.76	0.078	-.1013894	.0053832
4	2		.0689921	.0277125	2.49	0.013	.0146764	.1233078
4	3		-.149879	.0276958	-5.41	0.000	-.2041619	-.0955961
4	4		-.2494376	.0262669	-9.50	0.000	-.3009201	-.1979552
4	5		-.2294373	.0329708	-6.96	0.000	-.2940593	-.1648154
4	6		-.2651648	.0304478	-8.71	0.000	-.3248417	-.2054879
4	7		-.2012276	.0434808	-4.63	0.000	-.2864487	-.1160066
4	8		-.237514	.047931	-4.96	0.000	-.3314574	-.1435705
4	9		-.3454359	.0574538	-6.01	0.000	-.4580436	-.2328281
4	10		.361442	.1296871	2.79	0.005	.107259	.6156251
4	11		-.2549261	.0651591	-3.91	0.000	-.3826362	-.127216
4	12		.0628139	.0284013	2.21	0.027	.0071481	.1184796
5	1		-.0735907	.0272336	-2.70	0.007	-.1269679	-.0202136
5	2		.153768	.0277026	5.55	0.000	.0994717	.2080643
5	3		-.0573014	.0276795	-2.07	0.038	-.1115523	-.0030504

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5	4		-.1146992	.0262582	-4.37	0.000	-.1661645	-.0632339
5	5		-.0896943	.0329621	-2.72	0.007	-.1542992	-.0250895
5	6		-.3199139	.0304376	-10.51	0.000	-.3795707	-.2602571
5	7		-.267519	.0434786	-6.15	0.000	-.3527358	-.1823021
5	8		-.2299726	.0479279	-4.80	0.000	-.3239098	-.1360353
5	9		-.2532711	.0574499	-4.41	0.000	-.3658713	-.1406709
5	10		.40612	.129642	3.13	0.002	.1520254	.6602147
5	11		-.2493646	.0651352	-3.83	0.000	-.3770276	-.1217015
5	12		.0092776	.0283809	0.33	0.744	-.0463482	.0649033
6	1		-.0611505	.0272384	-2.25	0.025	-.114537	-.007764
6	2		-.0288254	.0276995	-1.04	0.298	-.0831156	.0254648
6	3		.137969	.027668	4.99	0.000	.0837406	.1921975
6	4		.0573118	.026254	2.18	0.029	.0058546	.108769
6	5		-.0000337	.032956	-0.00	0.999	-.0646265	.0645592
6	6		-.1275594	.0304234	-4.19	0.000	-.1871885	-.0679303
6	7		-.2454359	.0434725	-5.65	0.000	-.3306409	-.160231
6	8		-.1109783	.0479245	-2.32	0.021	-.2049089	-.0170476
6	9		-.0961455	.0574484	-1.67	0.094	-.2087427	.0164517
6	10		.4851987	.129636	3.74	0.000	.2311157	.7392817
6	11		.2608672	.0651337	4.01	0.000	.1332071	.3885274
6	12		.1016136	.0283711	3.58	0.000	.0460071	.1572201
7	1		-.1144581	.0272466	-4.20	0.000	-.1678608	-.0610554
7	2		-.0486276	.0277023	-1.76	0.079	-.1029232	.0056681
7	3		.09892	.0276696	3.58	0.000	.0446885	.1531516
7	4		.1976575	.0262544	7.53	0.000	.1461996	.2491154
7	5		.1327074	.0329575	4.03	0.000	.0681115	.1973032
7	6		-.0251411	.0304199	-0.83	0.409	-.0847632	.0344811
7	7		-.1764914	.0434654	-4.06	0.000	-.2616825	-.0913004
7	8		-.0026951	.0479218	-0.06	0.955	-.0966205	.0912302

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7	9		-.0121442	.0574487	-0.21	0.833	-.1247421	.1004537
7	10		.1613382	.1296556	1.24	0.213	-.0927832	.4154596
7	11		.108717	.0651396	1.67	0.095	-.0189548	.2363887
7	12		-.0821874	.0283745	-2.90	0.004	-.1378006	-.0265742
8	1		-.1936259	.0272512	-7.11	0.000	-.2470376	-.1402143
8	2		-.0149844	.0277049	-0.54	0.589	-.0692853	.0393165
8	3		.2273639	.027673	8.22	0.000	.1731256	.2816022
8	4		.3113171	.0262567	11.86	0.000	.2598547	.3627796
8	5		.1826084	.0329608	5.54	0.000	.1180061	.2472106
8	6		.0228173	.0304224	0.75	0.453	-.0368097	.0824443
8	7		-.139358	.0434632	-3.21	0.001	-.2245447	-.0541713
8	8		.063305	.0479217	1.32	0.186	-.0306202	.1572301
8	9		.1134772	.0574504	1.98	0.048	.000876	.2260783
8	10		-.0101577	.1296492	-0.08	0.938	-.2642665	.2439512
8	11		.0840646	.0651405	1.29	0.197	-.043609	.2117382
8	12		-.090885	.028377	-3.20	0.001	-.1465031	-.035267
9	1		-.1908372	.0272559	-7.00	0.000	-.2442579	-.1374164
9	2		-.0557687	.027707	-2.01	0.044	-.1100737	-.0014637
9	3		.1786621	.0276768	6.46	0.000	.1244163	.2329079
9	4		.3325584	.0262588	12.66	0.000	.2810918	.384025
9	5		.2574	.0329634	7.81	0.000	.1927926	.3220073
9	6		.1157224	.030426	3.80	0.000	.0560882	.1753565
9	7		-.0541954	.0434668	-1.25	0.212	-.139389	.0309982
9	8		.1725314	.0479254	3.60	0.000	.0785989	.2664639
9	9		.2152535	.0574524	3.75	0.000	.1026484	.3278586
9	10		.1396072	.1296521	1.08	0.282	-.1145074	.3937218
9	11		.065831	.0651429	1.01	0.312	-.0618473	.1935094
9	12		-.1043098	.0283792	-3.68	0.000	-.1599324	-.0486873
10	1		-.1930169	.027259	-7.08	0.000	-.2464438	-.13959

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10	2		-.0475375	.0277085	-1.72	0.086	-.1018455	.0067704
10	3		.2011766	.0276795	7.27	0.000	.1469255	.2554277
10	4		.3523089	.0262602	13.42	0.000	.3008396	.4037782
10	5		.3413859	.0329655	10.36	0.000	.2767745	.4059973
10	6		.2265783	.0304295	7.45	0.000	.1669373	.2862194
10	7		.1189769	.0434755	2.74	0.006	.0337662	.2041877
10	8		.2112907	.0479317	4.41	0.000	.1173459	.3052354
10	9		.2805408	.0574549	4.88	0.000	.1679308	.3931507
10	10		.3178283	.1296568	2.45	0.014	.0637046	.571952
10	11		.1018301	.0651447	1.56	0.118	-.0258516	.2295118
10	12		-.1081592	.0283807	-3.81	0.000	-.1637847	-.0525337
11	1		-.2040748	.0272597	-7.49	0.000	-.257503	-.1506466
11	2		-.0210742	.0277085	-0.76	0.447	-.0753821	.0332336
11	3		.2087192	.0276804	7.54	0.000	.1544663	.2629721
11	4		.3227812	.0262608	12.29	0.000	.2713108	.3742516
11	5		.3905209	.0329665	11.85	0.000	.3259075	.4551344
11	6		.2813626	.0304324	9.25	0.000	.221716	.3410093
11	7		.2164138	.0434853	4.98	0.000	.1311839	.3016437
11	8		.3065274	.0479381	6.39	0.000	.21257	.4004848
11	9		.3826113	.0574813	6.66	0.000	.2699495	.4952731
11	10		.3731763	.129659	2.88	0.004	.1190483	.6273043
11	11		.0667286	.0651446	1.02	0.306	-.060953	.1944102
11	12		-.0856667	.0283809	-3.02	0.003	-.1412926	-.0300409
12	1		-.1924838	.0272588	-7.06	0.000	-.2459104	-.1390573
12	2		.0021586	.0277075	0.08	0.938	-.0521473	.0564645
12	3		.1955176	.0276803	7.06	0.000	.1412649	.2497702
12	4		.3251921	.0262607	12.38	0.000	.2737219	.3766622
12	5		.4082454	.0329667	12.38	0.000	.3436315	.4728592
12	6		.3203612	.0304347	10.53	0.000	.26071	.3800123

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12	7		.2648141	.0434927	6.09	0.000	.1795695	.3500586
12	8		.3676383	.0479433	7.67	0.000	.2736707	.4616059
12	9		.4478609	.0574585	7.79	0.000	.3352439	.5604779
12	10		.3775411	.129659	2.91	0.004	.123413	.6316693
12	11		.0936243	.0651434	1.44	0.151	-.034055	.2213037
12	12		-.106807	.0283804	-3.76	0.000	-.1624318	-.0511822
13	1		-.1666382	.0272582	-6.11	0.000	-.2200636	-.1132129
13	2		.0184396	.0277067	0.67	0.506	-.0358647	.072744
13	3		.1620323	.02768	5.85	0.000	.1077802	.2162845
13	4		.2432633	.0262605	9.26	0.000	.1917934	.2947331
13	5		.4179244	.0329673	12.68	0.000	.3533094	.4825394
13	6		.366486	.030436	12.04	0.000	.3068324	.4261396
13	7		.3387177	.0435004	7.79	0.000	.2534582	.4239772
13	8		.4322999	.0479489	9.02	0.000	.3383214	.5262784
13	9		.4572664	.0574602	7.96	0.000	.344646	.5698868
13	10		.3859157	.1296595	2.98	0.003	.1317867	.6400447
13	11		.1393143	.0651426	2.14	0.032	.0116367	.266992
13	12		-.1222617	.02838	-4.31	0.000	-.1778857	-.0666377
14	1		-.1532099	.0272571	-5.62	0.000	-.2066331	-.0997867
14	2		.0154797	.0277056	0.56	0.576	-.0388226	.0697819
14	3		.1236133	.0276789	4.47	0.000	.0693634	.1778632
14	4		.2238464	.02626	8.52	0.000	.1723775	.2753154
14	5		.4087012	.0329673	12.40	0.000	.3440862	.4733162
14	6		.3736899	.0304369	12.28	0.000	.3140345	.4333453
14	7		.3745647	.0435065	8.61	0.000	.2892932	.4598362
14	8		.4612744	.0479529	9.62	0.000	.3672881	.5552608
14	9		.4775622	.0574608	8.31	0.000	.3649407	.5901838
14	10		.4232264	.1296572	3.26	0.001	.1691018	.6773509
14	11		.1042582	.0651416	1.60	0.109	-.0234176	.2319339

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14	12		-.1180243	.0283795	-4.16	0.000	-.1736472	-.0624013
15	1		-.1915974	.027258	-7.03	0.000	-.2450223	-.1381724
15	2		.0199387	.0277053	0.72	0.472	-.0343629	.0742403
15	3		.1195705	.0276778	4.32	0.000	.0653227	.1738182
15	4		.2014453	.0262596	7.67	0.000	.1499771	.2529134
15	5		.416123	.0329669	12.62	0.000	.3515088	.4807372
15	6		.4087313	.0304375	13.43	0.000	.3490747	.4683879
15	7		.4621449	.0435093	10.62	0.000	.3768679	.5474219
15	8		.5489914	.0479555	11.45	0.000	.455	.6429829
15	9		.5533408	.0574608	9.63	0.000	.4407193	.6659624
15	10		.4624758	.129656	3.57	0.000	.2083537	.7165978
15	11		.103542	.0651419	1.59	0.112	-.0241343	.2312183
15	12		-.1476687	.0283809	-5.20	0.000	-.2032944	-.092043
16	1		-.1507552	.0272654	-5.53	0.000	-.2041946	-.0973158
16	2		-.0261666	.0277075	-0.94	0.345	-.0804726	.0281394
16	3		.125567	.0276777	4.54	0.000	.0713196	.1798145
16	4		.1851721	.0262598	7.05	0.000	.1337035	.2366406
16	5		.4181657	.0329671	12.68	0.000	.3535511	.4827802
16	6		.4281028	.0304385	14.06	0.000	.3684443	.4877614
16	7		.5075578	.0435105	11.67	0.000	.4222784	.5928373
16	8		.5891342	.0479565	12.28	0.000	.4951407	.6831276
16	9		.5992323	.0574608	10.43	0.000	.4866107	.711854
16	10		.4756053	.129658	3.67	0.000	.2214793	.7297313
16	11		.2055889	.0651506	3.16	0.002	.0778956	.3332822
16	12		.1274906	.0283898	4.49	0.000	.0718474	.1831338
17	1		.1196224	.0272814	4.38	0.000	.0661516	.1730932
17	2		.1292874	.0277148	4.66	0.000	.0749672	.1836076
17	3		.1671805	.0276775	6.04	0.000	.1129333	.2214277
17	4		.1876946	.0262601	7.15	0.000	.1362256	.2391637

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17	5		.4077823	.0329666	12.37	0.000	.3431687	.4723958
17	6		.3668159	.0304369	12.05	0.000	.3071605	.4264714
17	7		.4142717	.0435059	9.52	0.000	.3290013	.4995421
17	8		.4601048	.0479544	9.59	0.000	.3661155	.554094
17	9		.4889506	.0574606	8.51	0.000	.3763294	.6015718
17	10		.333704	.1296611	2.57	0.010	.0795718	.5878361
17	11		.4272335	.0651657	6.56	0.000	.2995105	.5549565
17	12		.3060464	.0284021	10.78	0.000	.2503791	.3617137
18	1		-.1168096	.0272817	-4.28	0.000	-.170281	-.0633382
18	2		.111812	.0277222	4.03	0.000	.0574774	.1661467
18	3		.1682641	.0276774	6.08	0.000	.1140171	.2225112
18	4		.1731863	.0262596	6.60	0.000	.1217182	.2246543
18	5		.3513097	.0329649	10.66	0.000	.2866994	.4159199
18	6		.255915	.0304334	8.41	0.000	.1962664	.3155635
18	7		.2322545	.0434959	5.34	0.000	.1470038	.3175052
18	8		.2991397	.0479459	6.24	0.000	.205167	.3931123
18	9		.3830771	.057459	6.67	0.000	.2704591	.4956952
18	10		.4896464	.1296735	3.78	0.000	.23549	.7438028
18	11		.1850944	.0651673	2.84	0.005	.0573684	.3128205
18	12		.0829539	.0284009	2.92	0.003	.0272889	.1386188
19	1		-.1697835	.0272759	-6.22	0.000	-.2232434	-.1163235
19	2		-.023006	.0277194	-0.83	0.407	-.0773353	.0313232
19	3		.6307583	.0276825	22.79	0.000	.5765014	.6850151
19	4		.4480415	.0262612	17.06	0.000	.3965703	.4995127
19	5		.3818741	.0329639	11.58	0.000	.3172657	.4464825
19	6		.2087987	.0304302	6.86	0.000	.1491564	.268441
19	7		.1827462	.0434858	4.20	0.000	.0975152	.2679772
19	8		.2648267	.0479404	5.52	0.000	.1708649	.3587885
19	9		.6027814	.0574605	10.49	0.000	.4901604	.7154024

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19	10		.7137066	.129678	5.50	0.000	.4595414	.9678718
19	11		.0725341	.0651607	1.11	0.266	-.055179	.2002473
19	12		.0360688	.0283968	1.27	0.204	-.0195881	.0917256
20	1		-.2018241	.0272687	-7.40	0.000	-.2552701	-.1483782
20	2		-.0419097	.0277139	-1.51	0.130	-.0962283	.0124089
20	3		.3651992	.0276833	13.19	0.000	.3109408	.4194576
20	4		.5860935	.0262644	22.32	0.000	.5346159	.6375711
20	5		.423892	.0329646	12.86	0.000	.3592823	.4885017
20	6		.2338156	.0304292	7.68	0.000	.1741753	.293456
20	7		.1454117	.0434804	3.34	0.001	.0601913	.230632
20	8		.2618833	.0479414	5.46	0.000	.1679195	.355847
20	9		.4826832	.0574587	8.40	0.000	.3700657	.5953007
20	10		.4468343	.1296638	3.45	0.001	.1926968	.7009718
20	11		-.0089802	.065152	-0.14	0.890	-.1366762	.1187158
20	12		-.0835764	.0283916	-2.94	0.003	-.1392231	-.0279297
21	1		-.1695737	.0272587	-6.22	0.000	-.2230001	-.1161474
21	2		.0185136	.0277068	0.67	0.504	-.0357909	.0728181
21	3		.1705758	.0276768	6.16	0.000	.1163299	.2248216
21	4		.273744	.0262604	10.42	0.000	.2222744	.3252136
21	5		.3029781	.0329628	9.19	0.000	.2383719	.3675844
21	6		.1722358	.0304284	5.66	0.000	.112597	.2318745
21	7		.1373461	.0434764	3.16	0.002	.0521336	.2225586
21	8		.2201679	.0479313	4.59	0.000	.1262238	.3141119
21	9		.2641871	.0574532	4.60	0.000	.1515805	.3767938
21	10		.2212478	.1296421	1.71	0.088	-.0328471	.4753427
21	11		.0333184	.06514	0.51	0.609	-.0943543	.160991
21	12		-.0807588	.0283834	-2.85	0.004	-.1363894	-.0251282
22	1		-.1398901	.0272468	-5.13	0.000	-.1932931	-.0864871
22	2		.0417333	.0277002	1.51	0.132	-.0125583	.096025

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22	3		.1230789	.0276693	4.45	0.000	.0688479	.1773099
22	4		.1111608	.0262543	4.23	0.000	.059703	.1626186
22	5		.1039504	.0329574	3.15	0.002	.0393549	.1685459
22	6		.1241862	.0304225	4.08	0.000	.064559	.1838134
22	7		.0521849	.0434655	1.20	0.230	-.0330063	.137376
22	8		.1760479	.0479229	3.67	0.000	.0821204	.2699753
22	9		.1801937	.0574484	3.14	0.002	.0675964	.292791
22	10		.1474401	.1296182	1.14	0.255	-.106608	.4014882
22	11		-.0351011	.065128	-0.54	0.590	-.1627501	.092548
22	12		-.0364058	.0283741	-1.28	0.199	-.0920183	.0192066
23	1		-.110804	.0272364	-4.07	0.000	-.1641867	-.0574213
23	2		0	(omitted)				
23	3		0	(omitted)				
23	4		0	(omitted)				
23	5		0	(omitted)				
23	6		0	(omitted)				
23	7		0	(omitted)				
23	8		0	(omitted)				
23	9		0	(omitted)				
23	10		0	(omitted)				
23	11		0	(omitted)				
23	12		0	(omitted)				
dow								
1			-.007748	.0009957	-7.78	0.000	-.0096995	-.0057965
2			-.0108548	.0010165	-10.68	0.000	-.012847	-.0088626
3			-.014829	.0010207	-14.53	0.000	-.0168295	-.0128285
4			-.0233027	.0010126	-23.01	0.000	-.0252874	-.021318
5			-.0277914	.0009937	-27.97	0.000	-.029739	-.0258438

6		.0016071	.0009282	1.73	0.083	-.0002122	.0034264
z							
2		-.2931634	.0214663	-13.66	0.000	-.3352366	-.2510901
3		-.2537751	.0505821	-5.02	0.000	-.3529147	-.1546355
4		-.2472768	.0191364	-12.92	0.000	-.2847837	-.20977
5		-.2566251	.0512649	-5.01	0.000	-.3571029	-.1561474
6		.4555917	.0757971	6.01	0.000	.3070314	.604152
7		.0708058	.0179562	3.94	0.000	.0356122	.1059994
8		-.3409807	.0507277	-6.72	0.000	-.4404057	-.2415557
9		-.1157141	.0772266	-1.50	0.134	-.267076	.0356478
10		.0395241	.0153385	2.58	0.010	.009461	.0695872
11		-.0795346	.0208126	-3.82	0.000	-.1203267	-.0387425
tmax		-.002246	.0000377	-59.55	0.000	-.0023199	-.0021721
tmin		-.0016201	.0000429	-37.76	0.000	-.0017042	-.001536
_cons		-.3701252	.0433306	-8.54	0.000	-.4550521	-.2851984

D. Appendix 4 – Guide to Demand Curve Development Model

The model is a Microsoft Excel workbook that simulates revenues and expenditures given a set of user-defined and built-in input parameters. The workbook can be divided into three parts: (1) input sheets, (2) the “Model” sheet and (3) output sheets. The input sheets supply parameters produced by outside sources. The “Model” sheet is where the actual calculations of revenues and expenditures are performed. The output sheets show the results of simulations that NERA has performed.

Input Sheets: The sheets to the right of the “Model” sheet (e.g. “Reference Tables”, “Energy Curve Raw”) contain functions and parameters produced by outside sources. The energy curve is the result of the combination of the econometric results and the MAPS adjustments. It is the per kW annual net energy revenue at various excess levels prior to consideration of EFORD, seasonal capacity rating differences and Ancillary Service revenues. The “Current Curve” sheet contains FERC-approved values for the current NYISO demand curve. The “Reference Tables” sheet contains levelized fixed charges and overnight capital costs calculated by Sargent & Lundy. The values in these input sheets are not meant to be changed by users.

“Model” Sheet: The “Model” sheet allows users to alter certain parameters and run the simulation. User-defined input parameters can be found in the tan areas of the “Model” sheet. Users can change these values to simulate different market conditions. Values in yellow are dependent on other parameters and should not be altered. Values that are shaded out are not relevant given the other parameters. For example, the “kink” variable that determines where the curve kinks is not relevant if there is no kink specified (i.e., if the x-intercept of the first and second slanted segments are identical).

To run the simulation, users click the “Calculate Demand” Button, which solves for the demand curve that allows for full cost recovery given the inputs and parameters. Values in the areas shaded blue are the results of intermediate calculations, including revenue and expenditure streams. Outputs such as the amortization period and demand curve reference values are shown in the pastel green rectangle. The supernormal net revenue variable should always be zero after clicking “Calculate Demand”.

Output Sheets: The “Results Summary” sheet show the results of certain runs that NERA has performed.

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The NYISO capacity model uses a Monte Carlo simulation to estimate capacity levels for demand payment and energy payment calculations. This simulation assumes capacity levels are normally distributed. ~~[NOTE: because of the way the model is structured (e.g. averaging 100 observation samples of simulated capacity levels), the average simulated capacity levels that are in the pro forma will be normally distributed regardless of the underlying distribution of the simulation (central limit theorem).]~~ In each run of the model, the normal distribution is specified by two parameters, the expected value and standard deviation assumptions. These assumptions are explained in Section IV of this report.

Seasonal Considerations: The model was enhanced from the version used in 2007 to incorporate a seasonal view of the Demand Curve. If the seasonal toggle is set to true, inputs are required for the seasonal capacity ratios that will be used to develop the Demand Curve the Winter Summer Ratio (WSR). The model will then simulate Summer Capability Period and Winter Capability Period demand revenue separately using the relevant ratio and seasonal peaking unit capacity. This feature has been used in developing this report. WSRs are developed consistent with the underlying capacity data used to develop net Cone. In 2010, the model was also enhanced to allow for an input vector of property taxes, option of deliverability and option of Summer and Winter Capability Period minimum payments. The user can elect to input a vector of property taxes by toggling the user-input property tax option and inputting the annualized tax rates into the corresponding cells indicated by year. This feature will be automatically disabled if the user attempts to activate the user-input property tax toggle in conjunction with property taxes implicit in the levelized carrying charge, however, it is possible to utilize both a fixed or extra tax in addition to the user-input property tax option. Finally, the model is set up so that all years are treated as having the same level of excess, the MW capacity of the hypothetical unit. However, the option remains to treat the first year or first three years as having a different level of excess. This was a legacy of the tariff specification that energy revenues be developed at a level just above the minimum required capacity level. This feature has not been removed from the Model, but we have not used this feature to develop Demand Curves for this reset.

~~NTD—We anticipate posting a complete model with energy revenue data by April 22, 2013.~~

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