Attachment III

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

New York Independent System Operator, Inc. Docket No. ER14-___-000

AFFIDAVIT OF
EUGENE T. MEEHAN

Mr. Eugene T. Meehan declares:

1. I have personal knowledge of the facts and opinions herein and if called to testify could and would testify competently hereto.

I. Purpose of this Affidavit

2. The purpose of my affidavit is to present and describe the independent report and analyses provided to the NYISO in connection with its instant filing to update the Installed Capacity ("ICAP") Demand Curves[1] and to describe analyses that were performed at NYISO's request subsequent to that report. I was, as described later herein, responsible for preparing that report and those analyses. The report includes an independent statistical and production cost modeling analysis of Energy and Ancillary Service revenues, an independent assessment of construction costs of peaking technologies, a methodology for determining an appropriate amortization period to reflect an equilibrium level of excess capacity that was integrated with the zero crossing points of the ICAP Demand Curves, and assumptions to implement the methodology for determining an appropriate amortization period.

[1] Capitalized terms that are not otherwise defined herein shall have the meaning specified in the filing letter to which this Affidavit is attached or the meaning set forth in the Services Tariff as revised by the Commission's acceptance of the NYISO's filing to establish a New Capacity Zone and subsequent related filings in Docket Nos. ER12-360 and ER13-1380.

II. Qualifications

3. I am a Senior Vice President with NERA Economic Consulting (NERA) and have over thirty years of experience consulting with electric and gas companies. I have testified as an expert witness before numerous state and federal regulatory agencies, and in federal court and arbitration proceedings.

4. My consulting practice at NERA focuses on the areas of electricity tariff design, electricity procurement, wholesale power market design, electricity costing and pricing, market power analysis and mitigation, power contract analysis, and power cost risk management.

5. I have worked extensively on electric utility and electricity market issues in New York State. I have provided consulting services for New York electric companies on a continuous basis since 1980, advising the companies on production cost modeling, transmission expansion, competitive bidding and reliability and marginal generating capacity cost quantification. In 1987, I prepared and sponsored the New York Power Pool's position paper on competitive bidding for independent power producer supplies. That paper set forth the New York Power Pool's policy position on the establishment of competitive bidding processes, power purchase contracts based on avoided cost, and the various implementation issues. Many of these positions were adopted by the New York Public Service Commission ("NYPSC"). I provided testimony on behalf of the New York State investor-owned electric utilities concerning the proper methodology to use when analyzing the cost-effectiveness of conservation programs. This methodology was adopted by the NYPSC and used as the basis for demand-side management evaluation in New York from 1982 through 1988.

6. I worked with the NYISO as well as PJM Interconnection ("PJM") and ISO New England Inc. ("ISO-NE") in 2003 and 2004 to study the joint capacity market design proposal known as the Centralized Resource Adequacy Market or (CRAM) and was a co-author of NERA's CRAM report.

7. I was retained by National Grid to advise the load serving entities in New England with respect to the ISO-NE forward capacity market settlement negotiations and attended many of the settlement sessions.

8. I directed NERA's efforts in 2007 with respect to the update of the NYISO's ICAP Demand Curves for the 2008/2009 – 2010/2011 and 2011/2012 – 2013/2014, including developing the methodology for converting the total capital costs of the peaking unit to a levelized cost.

9. My Curriculum Vitae is attached as Exhibit A hereto.

III. Overview of the Independent ICAP Demand Curve Report and Process

10. In accordance with the Services Tariff, in the third quarter of 2012, the NYISO solicited proposals from qualified consultants to identify appropriate methodologies and to develop the ICAP Demand Curve parameters for the three Capability Years beginning in May 2014. The NYISO selected the team of NERA, with Sargent and Lundy (S&L) as a subcontractor to NERA. We began our analysis in November 2012 and met, either in person or telephonically, with stakeholders at Installed Capacity Working Group meetings on 12 occasions between December 2012 and August 2013. In addition to the ICAP Working Group meetings, we had separate conversations with stakeholders at their request in respect of the development of the ICAP Demand Curves. We evaluated and considered all oral and

written comments received. All NYISO stakeholders had an opportunity to provide input to, and comments on, our proposed assumptions, analysis, methodology, cost estimates, and preliminary and final results for the study. On August 2, 2013, NYISO released our final report for stakeholder review and comment ("NERA/S&L Report").[2]

11. The NERA/S&L Report contains four basic elements. These elements are: (1) an independent statistical and production cost model analysis of Energy and Ancillary Service revenues, (2) an independent assessment of construction costs of peaking technologies, (3) a methodology for determining an appropriate amortization period to reflect an equilibrium level of excess capacity that was integrated with the zero crossing point of the Demand Curves, and (4) assumptions to implement the methodology for determining an appropriate amortization period. In addition to examining these factors for the peaking unit, the report also examined these factors on an informational basis for a new combined cycle unit in each location.

12. The statistical analysis of Energy and Ancillary Services revenues used the most recent three years of hourly electricity prices by location and daily gas prices. The analysis considered both day ahead and real time prices and unit operating constraints including start times. The analysis was employed to estimate net energy revenues for the peaking unit and for the combined cycle unit based upon the historical resource mix and forecast load in the 2014/2015 to 2016/2017 period (the reset period). Net energy revenues were adjusted to

[2] "Independent Study to Establish Parameters of the ICAP Demand Curve for the New York Independent System Operator," August 2, 2013, prepared by NERA Economic Consulting, *available at* http://www.nyiso.com/public/webdocs/markets_operations/committees/bic_icapwg/meeting_materials/2013-08-13/Demand%20Curve%20FINAL%20Report%208-2-13.pdf

reflect the resource mix that would prevail in the reset period and to an Installed Capacity level that reflected the minimum capacity requirement plus the capacity of the peaking (or combined cycle) plant using results from the General Electric Multi Area Production System (MAPS). MAPS runs were executed by GE Energy Consulting under NERA's direction and the relative difference in hourly energy prices between MAPS runs using the historical and forecast resource mix and MAPS runs at alternate Installed Capacity levels with the forecast resource mix were used to use to adjust hourly energy prices developed from the econometric model and resulting net energy revenues. This approach combines the strengths of the statistical method, which can capture many details affecting locational prices that can not be directly modeled in a precise fashion in a production simulation model, with the strengths of a production simulation model which can capture the relative impacts of changes in resource mix and Installed Capacity levels that are more difficult to capture in a precise fashion using an econometric analysis.

13. The independent assessment of the construction costs of new peaking and combined cycle units was conducted by the engineering firm of S&L and represents a thorough cost estimate based on a conceptual design. S&L performs this work in its normal cost of business for entities contemplating construction of power plants and maintains the data needed to develop such estimates. S&L informed its analysis through interactions with stakeholders, the NYISO, and the New York Department of Environmental Conservation ("NYSDEC") to determine local environmental requirements and reviewed information available from entities currently developing power plants in New York State.

14. The methodology for determining an appropriate amortization period and the resulting value of the ICAP Demand Curve at the reference point to reflect equilibrium excess capacity

levels that are integrated with the zero crossing point of the ICAP Demand Curves is a carry over from the prior reset. A primary benefit of this methodology is that it internally and automatically adjusts the reference price to reflect the slope (also referred to as the zero crossing point) of the Demand Curve and can account for the revenue volatility associated with alternate slopes. This methodology was reviewed extensively with FERC Staff after the 2010 Demand Curve reset filing for the 2011/12 to 2013/14 period and was accepted by the Commission. In employing this methodology NERA assumed an average level of excess capacity equal to the capacity of the peaking unit or combined cycle unit as appropriate and as directed by a Commission's prior order.

15. In addition to new unit construction costs, O&M costs and net energy revenues, all of which have been discussed above there are several other factors that influence the determination of the amortization period and value of the ICAP Demand Curve at the reference point. I will discuss herein two of the most significant of these factors.

16. The first factor is the economic analysis period. This is the number of years over which the economics of the generating unit investment are examined and over which an investor will recover a return on and a return of invested capital if all events transpire exactly as modeled. While in the two previous resets NERA had used 30 years for both aeroderivative and larger frame turbine technologies, we reconsidered this assumption in light of current circumstances with respect to technological change, environmental regulation, the risk allowances in other aspects of determining the value at the reference point and the corresponding assumption used by PJM in the past and approved by the Commission and underlying the PJM settlement demand curve that is currently in effect.

17. With respect to technological progress, the ICAP Demand Curve model does account for a gradual technical progress of 0.25% per year -- roughly half the level forecast by the United States Department of Energy's Energy Information Administration. It does not, however, account for abrupt technology changes of the type that could change peaking unit technology and result in lower than expected revenue from an abrupt technology change. Such change can and has occurred. Two resets ago, the higher cost LM 6000 was replaced by the LMS100. In this reset the LMS100 could possibly be replaced with a Frame unit with an SCR. With such technology changes possible, investors will want to analyze a recovery period or economic life that is shorter than the potential physical life of the equipment to allow for the reduced revenue that will result from competition against new technology. The potential for such changes is one factor in recommending 20 and 25 year economic analysis periods – economic life.

18. Second there are environmental considerations. Carbon regulations are uncertain, but it is possible that over time, emissions restrictions or costs will apply to what are now new units and will more heavily impact higher heat rate alternatives. This is a consideration in using a shorter (20 year) economic analysis period for the less efficient frame units than the more efficient aeroderivative and combined cycle units.

19. Third we have considered the risk allowances in other aspects of the value of the ICAP Demand Curve at the reference point determination. There is very little specific allowance for any deviation from forecast conditions. The cost of capital methodology is based on merchant generator cost of capital, but the revenue model reflects only a limited set of uncertainties. Everything would need to go exactly as modeled for this return to be achieved over the economic analysis period, and an investor would be likely to require an economic

analysis period not so long that if events did not transpire exactly as expected there would still be a chance to make up for some of the lost return on and of capital. Setting the amortization period to 20 years for the F class frame technology, *i.e.*, its economic life, is reasonable and is more likely to result in prices that will attract investment in this technology recognizing that it is a less efficient and higher emitting technology than the combined-cycle and aeroderivative units. This is especially true when one considers an assumption over the economic analysis period is that there will be an average excess level of only about 200 MW. In addition as the unit ages, its life may be able to be extended but capital reinvestment would be required. The cost information that S&L provides does not include an allowance for capital addition that could be required as the unit ages. As the period would extend beyond 20 years for the F class frame unit, the costs could be understated by the amount of any required capital refurbishment. Finally, PJM has used an economic analysis period of 20 years in all of its resets including in the settlement based values currently in effect.[3]

20. The second factor is return on equity. NERA recommended a return of 12.5%. The equity cost of 12.5% is based on a CAPM derived estimate that averages 11.29% over three generation companies for which we are able to observe data plus a calibration adder of 1.21%. In the 2010 reset, we used a CAPM analysis over five generation companies. A calibration adjustment was not examined. A calibration adjustment was examined in the

[3] This does not imply PJM uses the 20 year equivalent amortization period that is used by NYISO. The 20 year period used by PJM is used to develop the value at a one percent excess level. The NYISO equivalent amortization period is at the reference level. Hence, the PJM amortization period, stated on the same basis as the NYISO's curve would be less than 20 years. Also PJM uses a nominal levelized carrying charge while NERA in its recommendations for NYISO uses a real levelized carrying charge. All else equal, a real levelized carrying charge with a 20 year amortization period would be equivalent to a nominal levelized carrying charge with a 17 to 18 year amortization period. Hence, while PJM uses a 20 year economic life, the implied amortization period stated in terms equivalent to that used by NYISO would be in the area of 15 to 17 years.

2013 reset as the result yielded by the CAPM analysis appeared potentially too low relative to regulated rates of return and as the CAPM is subject to bias at times during the interest rate cycle. Additionally, external factors such as the Federal Reserve quantitative easing program could possibly change the relationship between government debt costs and market equity costs (the market risk premium) and distort CAPM results. Given these concerns it was deemed prudent to calibrate CAPM results.

21. The calibration adjustment was determined by applying the CAPM method to a sample of regulated utilities including two New York utilities – Consolidated Edison Company of New York, Inc. and Central Hudson Gas and Electric Corporation. On average, the CAPM return for the five regulated entities was 7.72% while the CAPM return for the two New York utilities was 7.65%. Regulators are not, however, limiting returns for regulated utilities to the mid to high 7% range. Allowed returns are between 9.5% and 10.0%, with returns in New York currently around 9.3%. The calibration adjustment was applied conservatively to adjust the CAPM returns by the difference between the observed returns and a low end regulated return of about 9%. This difference raises the observed CAPM to 12.5% (rounded). Regulators have a wider tool kit for looking at regulated utilities and can consider discounted cash flow methods. CAPM is the only feasible empirical method for looking at generation companies returns as these companies do not pay dividends. The CAPM analyses used an assumed equity risk premium of 6.62%, which was based on long term historic returns.

22. One issue with using CAPM is that the equity market premium can deviate from the long term average. This is the likely reason why the CAPM method for regulated entities yields a return lower than that being allowed by regulators. It is also an explanation consistent with the fact the Federal Reserve actions are keeping long government yields low. To the extent

the Federal Reserve actions lower the risk free or government rates and not equity costs by the same magnitude, a logical assumption, the equity market risk premium will be understated by the long term historic average. The unique current conditions in financial markets require that a calibration adjustment be examined. There is no logical reason why a bias in the CAPM would not apply to all equity categories equally as the source of any such bias is likely a variable such as the market risk premium assumption that affects all categories. Hence, having found a bias by viewing the regulated utility results, it is appropriate to correct for this bias by adjusting the CAPM results for the generators to calibrate to current conditions.

23. The addition of a calibration examination is not a method change but only an additional step that is necessary because of current financial market conditions. The calibration examination resulted in adjustment because of the observed data. It is possible that a zero or even negative calibration may have been indicated by the data. The adjustment is conservative and a higher adjustment could easily be justified. It calibrates to regulated returns even lower than allowed New York returns which are among the lowest in the country.

24. NERA examined the shape and slope of the Demand Curves and recommended that the zero crossing point for the NYCA ICAP Demand Curve be moved out to 113.5%, that the zero crossing point for the NYC ICAP Demand Curve be moved in to 116.5%, that the G-J Locality zero crossing point be set at 115% and that the LI zero crossing point be maintained at 118%. These recommendations were based on loss of load expectation studies and value of loss load studies that NYISO had conducted working with FTI Consulting during 2012 in a comprehensive review of the Capacity Market, on NERA's concurrence with FTI's recommendation that it would be desirable for the curves to reflect reliability value at various

levels of excess and on NERA's analysis and determination that moving the curves as recommended would not conflict with any of the other elements that the zero crossing point supports including providing revenue stability in light of new additions of economic scale. NERA recommended a move half way toward the points identified in the FTI report recognizing that reliability calculations are sensitive and that it would not be desirable to change and have to reverse course in the next reset.

IV. **Analyses Performed for NYISO Subsequent to the NERA/S&L Report**

25. Subsequent to the finalization of the NERA/S&L Report, several additional analyses were performed at NYISO's request. First, the ICAP Demand Curves in the NERA/S&L Report were adjusted for the September 6, 2013 Staff recommendation to utilize the existing zero crossing points for NYCA and NYC. At the independent Market Monitoring Unit's suggestion, NYISO further examined the reliability studies done for the FTI report concluded that reliability studies are very sensitive to various assumptions such as the topology of the transmission system. While NERA had considered this and for that reason recommended a move half way toward the point indicated by the studies, NYISO considering the need for stability in the ICAP Demand Curve process based its recommendations on the existing zero crossing points for NYCA and NYC.

26. Second subsequent to completing the NERA/S&L Report, additional data became available as to temperature and humidity conditions at the time of seasonal peak. Summer and winter DNMC ratings are based on these data. S&L determined revised summer and winter DNMC rating based on these data and NERA worked with NYISO to reflect the revised data in the development of the recommended ICAP Demand Curves. The modifications are minor – having an impact of less than one half of one percent.

27. The NYISO staff ICAP Demand Curves recommended in the September 6, 2013 report accurately reflect these two adjustments and in all other aspects are consistent with the NERA/S&L Report.

28. In addition, NYISO asked NERA and S&L to develop ICAP Demand Curves based on a simple cycle frame combustion turbine unit with an SCR. S&L developed costs data for such a unit in the various Localities assuming that a system to diffuse exhaust air and lower its temperature would be constructed as part of the SCR and would work without problems or need for extra cost other than those costs associated with constructing, operating and maintaining the exhaust air diffusion equipment appropriate for the larger F class frame turbine.[4] NERA estimated net energy revenues and ICAP Demand Curves for these units using the ICAP Demand Curve model and assumptions described above, except that the summer and winter DNMC ratings were not based on the updated temperature and humidity data at time of historic seasonal peaks.[5] These results are also included in the September 6, 2013 NYISO report.

[4] S&L had no basis on which to make assumptions for items like SCR O&M cost impacts in such a system or forced outage rates. It did consider the impact of the required fans on net heat rate and capacity ratings.

[5] As NYISO staff was not recommending these curves and the adjustment had a very small impact, NYISO NERA and S&L agreed that such a refinement was unnecessary at the time of the September 6, 2013 report.

29. NYISO retained the Brattle Group (Brattle) to examine the viability and cost of the simple cycle frame unit with an SCR. Brattle issued a report finding the simple cycle frame unit with an SCR was technically feasible and concluded, *inter alia*, that the S&L cost estimates for a Frame unit with an SCR developed for the NYISO Staff September 6, 2103 report were reasonably conservative. NYISO requested that S&L refine the summer and winter DNMC values for these units to reflect the more accurate temperature and humidity assumptions discussed above and that NERA develop ICAP Demand Curves reflecting the S&L costs assumptions, the revised ratings, the remaining assumptions in the NERA/S&L Demand Curve report and the zero crossing points in the September 6, 2013 NYISO Staff recommendations. These ICAP Demand Curves were supplied to NYISO and are included in the Brattle report.

This concludes my Affidavit.

ATTESTATION

I am the witness identified in the foregoing affidavit. I have read the affidavit and am familiar with its contents. The facts set forth therein are true to the best of my knowledge, information and belief.

Eugene Thomas Meehan

Eugene T. Meehan

Subscribed and sworn to before me
this 20 day of November, 2013.

Stefanie Bowen

Notary Public

My commission expires: 7-8-2015

STEFANIE BOWEN
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COMMISSION NO. 608537
COMM. EXP. 07-08-2015

NERA
Economic Consulting

EXHIBIT A

Eugene T. Meehan
Senior Vice President

National Economic Research Associates, Inc.
1255 23rd Street NW
Washington, DC 20037

EUGENE T. MEEHAN
Senior Vice President

Mr. Meehan is a Senior Vice President at NERA. He has over thirty years of experience consulting with electric and gas utilities and has testified as an expert witness before numerous state and federal regulatory agencies, as well as appeared in federal court and arbitration proceedings.

At NERA, Mr. Meehan's practice concentrates on serving energy industry clients, with a focus on helping clients manage the transition from regulatory to more competitive environments. He has performed consulting assignments for over fifty large electric, gas, and combination utilities in the areas of retail access, regulatory strategy, strategic planning, financial and economic analysis, merger and acquisition advisory services, power contract analysis, market power and market definition, stranded cost analysis, power pooling, power markets and risk management, ISO and PX development, and costing and pricing. In addition, he has advised numerous utilities on power procurement issues and administered power procurements on behalf of utilities and regulators.

Mr. Meehan has experience leading NERA's advisory work on several major restructuring and unbundling assignments. These assignments were multi-year projects that involved integration of regulatory and business strategy, as well as development of regulatory filings associated with the recovery of stranded cost and rate unbundling.

Education

Boston College, BA, Economics, *cum laude*
New York University (NYU), Graduate School of Business, completed core courses for the doctoral program.

Professional Experience

	NERA Economic Consulting
1999-	Senior Vice President
1996-1999	Vice President
1973-1980	Senior Economic Analyst; Research Assistant
	Deloitte & Touche Consulting Group
1994-1996	Principal
	Energy Management Associates, Inc.
1980-1994	Vice President

Areas of Expertise

Restructuring/Stranded Cost Recovery

Mr. Meehan has directed several multi-year projects associated with restructuring and stranded cost recovery. These projects involved facilitating the development of an integrated regulatory and business strategy and formulating regulatory filings to accomplish strategy. As part of these assignments, Mr. Meehan facilitated sessions with senior management to set and track filing strategy. Clients include Public Service Gas & Electric and Baltimore Gas and Electric.

Unbundling/Generation Pricing

Mr. Meehan has formulated unbundling strategies, with a specialization in generation pricing. He has advised several utilities in standard offer pricing and has testified on shopping credits on behalf of First Energy and Baltimore Gas and Electric.

Power Procurement

Mr. Meehan has been involved in power procurement activities for a variety of utilities and regulatory agencies. He has advised utilities in developing and implementing evaluation processes for new generation, with the objective of achieving the best portfolio evaluation. He has helped regulators in Ireland and Canada design and implement portfolio evaluation processes. He has testified before FERC and state regulatory agencies on competitive power procurement. In addition, Mr. Meehan helped to design and implement the New Jersey BGS auction process.

Power Contracts

Mr. Meehan has extensive experience with power contracts and power contract issues. He has reviewed and testified on the three principal types of power contracts: integrated utility to integrated utility contracts, IPP to utility contract, and integrated or wholesale utility to distribution utility contracts. He has testified in power contracts disputes on behalf of Carolina Power and Light, Duke Power Company, Southern Company, Orange and Rockland Utilities, and Tucson Electric Power. He has also advised Oglethorpe Power Corporation in the reform of its wholesale contracts with its distributor cooperative members.

Retail and Wholesale Settlements

In addition to his expertise on power pooling issues, Mr. Meehan has significant experience with assignments related to the settlement process. He has focused on the issues of credit management as new entrants appear in retail and wholesale markets and has designed efficient specifications for retail settlement systems, including the use of load profiling, and examined the risk and cost allocation issues of alternative settlement systems.

Risk Management

Mr. Meehan has advised several large utilities on price risk management. These assignments have included evaluation of price management service offers solicited from power marketers in association with management of assets and entitlements, as well as provision of price managed service for various terms.

Marginal Costs

Mr. Meehan has provided comprehensive marginal cost analyses for over 25 North American Utilities. These assignments required detailed knowledge of utility operations and planning.

Power Supply and Transmission Planning

Mr. Meehan has advised electric utilities on economic evaluations of generation and transmission expansion. He has testified on the economics of particular investments, the prudence of planning processes, and the prudence of particular investment decisions.

Generation Strategy

Mr. Meehan has led NERA efforts on a client task force charged with developing an integrated generation asset/power marketing strategy.

Power Pooling

Mr. Meehan has in-depth working knowledge of the operating, accounting, and settlement processes of all United States power pools and representative international power pools. He has provided consulting services for New York Power Pool members on a continuous basis since 1980, advising the Pool and its members on production cost modeling, transmission expansion, competitive bidding and reliability, and marginal generating capacity cost quantification. In NEPOOL, he has quantified the benefits of continued utility membership in the Pool and the impact of the Pool settlement process on marginal cost. He has worked with a major PJM utility to explore the impact of PJM restructuring proposals upon generating asset valuation and examine the implications of alternative restructuring proposals. He has consulted for Central and Southwest Corporation, Entergy, and Southern Company on issues that involved the internal pooling arrangements of the utility operating companies of those holding companies, as well as for various utilities on the impact of pooling arrangements on strategic alternatives.

Representative Assignments

Worked with Public Service Electric & Gas Company (PSE&G) to direct a three year NERA advisory effort on restructuring. Facilitated a two-day senior management meeting to set regulatory strategy in 1997. Throughout 1997 and 1998, worked over half time at PSE&G to help implement that strategy and advised on testimony preparation, cross-examination, and briefing. Also advised PSE&G on business issues related to securitization, energy settlement and credit requirements for third party suppliers. During 1999, advised PSE&G during settlement negotiations and litigation of the settlement. PSE&G achieved a restructuring outcome that involved continued ownership of generation by an affiliate and the securitization of $2.5 billion in stranded costs.

Worked on separate assignments for a large utility in the Northeast and a large utility in the Southeast, advising on the evaluation of risk management offers from power marketers. The assignments included reviewing proposals, attending interviews with marketers and providing advice on these, and the developing analytical software to evaluate offers.

Worked with government of Ontario beginning in 2004 to help design the RFP and economic evaluation process for the solicitation of 2500 Mw of new generating capacity. Supervising NERA’s portfolio-based economic evaluation on behalf of the Ontario Ministry of Energy.

Testified on behalf of Pacific Gas & Electric Company before the FERC in a case benchmarking the PSA between the distribution utility and a soon-to-be-created generating company. This effort involved developing detailed expertise in applying the Edgar standard and a detailed review of DWR procurement during the western power crisis. In addition, this effort involved the review of more than 100 power contracts in the WECC.

Directed NERA’s efforts, on behalf of the electricity regulator in Ireland, to design an RFP and implementation process for the purchase of 500 Mw of new generating capacity in 2003. NERA advised on the RFP, the portfolio evaluation method, and the power contract and also conducted the economic evaluation.

Reviewed the economic evaluation conducted by Southern Company Service for affiliated operating companies in connection with an RFP for over 2000 Mw of new generating capacity. Submitted testimony before FERC on behalf of Southern Company Service.

Worked with Baltimore Gas and Electric (BG&E) to conduct a one and one-half year consulting assignment that involved providing restructuring advice. The project began in March/April 1998 with senior management discussions and workshops on plan development and filing strategy. Advised BG&E in the development of testimony, rebuttal testimony, and public information dissemination. Worked to review and coordinate testimony from all witnesses and offered testimony on shopping credits and in defense of the case settlement. BG&E achieved a restructuring outcome enabling it to retain generation ownership. As part of this assignment, advised BG&E on generation valuation and unregulated generation business strategy.

Directed the efforts of a large Southeastern utility to develop a short-term power contract portfolio and to evaluate the relative value of power options, forwards, and unit contracts to determine the optimal mix of instruments to manage price risk.

Testified for XCEL Energy on the use of competitive bids for new generation needs. Examined whether XCEL was prudent not to explore a self-build plan and the reasonableness of relying on ten-year or shorter contracts as opposed to life-of-facility contracts, in order to meet needs and facilitate a possible future transition to competition. This project addressed the comparability of fixed bids to rate base plant additions.

Advised and testified on behalf of First Energy in the Ohio restructuring proceeding on the issues of generation unbundling and stranded cost. Defended the First Energy shopping credit proposal.

Advised Consolidated Edison and Northeast Utilities on merger issues and testified in Connecticut and New Hampshire merger proceedings. Testimony focused on retail competition in gas and electric commodity markets.

Directed NERA's effort to train selected representatives of a major European power company in American power marketing and risk management practices. The project involved numerous meetings and interviews with power marketing firms.

Led NERA's effort to advise the New England ISO on the development of an RTO filing. Examined performance-based ratemaking for transmission and market operator functions.

Examined ERCOT power market conditions during the period of time from 1997 to 1999 and testified on behalf of Texas New Mexico Power Company for the prudence of its power purchase activity.

Advised a Midwestern utility on restructuring of a wholesale contract with an affiliate. Involved forecasting of the unbundled wholesale cost-of-service and market prices, as well as development of a regulatory strategy for gaining approval of contract restructuring and the transfer of generation from regulated to EWG states.

Performed market price forecasts for numerous utility clients. These forecasts have employed both traditional modeling and newly developed statistical approaches.

Examined the credit issues associated with the entry of new entities into retail and wholesale settlement market. These assignments involved a review of current Pool credit procedures, examination of commodity and security trading credit requirements, coordination with financial institutions, and recommendations concerning credit exposure monitoring, credit evaluation processes, and credit requirements.

Oversight of EMA's consulting and software team in designing and implementing the LOLP capacity payment, a portion of the UK wholesale settlement system.

Advised Oglethorpe Power Corporation in the reform of its contracts with its distribution cooperative members and the evolution of full requirement power wholesale power contracts into contracts that preserve Oglethorpe's financial integrity and are suitable for a competitive environment.

Developed long run marginal and avoided costs of natural gas service, as well as avoided cost methods and procedures. These costs have been used primarily for the analysis of gas DSM opportunities. Clients include Consolidated Edison Company, Southern California Edison Company, Niagara Mohawk Power Corporation, and Elizabethtown Gas Company.

Review of power contracts and testimony in numerous power contract disputes.

Development of long run avoided costs of electricity service and avoided cost methods and procedures. These costs have been used to assess DSM and cogeneration, as well as to develop integrated resource plans. Clients include Public Service Company of Oklahoma, Central Maine Power Company, Duquesne Light Company, and the New York investor-owned utilities.

Advised Central Maine Power Company (CMP) on the development of a competitive bidding framework. This framework was implemented in 1984 and was the first of its kind in the nation. CMP adopted the framework outlined in EMA's report and won prompt regulatory approval.

Advised a utility in the development of an incentive ratemaking plan for a new nuclear facility. This assignment involved strategic analysis of alternate proposals and quantification of the financial impact of various ratemaking alternatives. Presented strategic and financial results in order to convince senior management to initiate negotiations for the incentive plan.

Advised and testified on behalf of the New York Power Pool utilities on the methodology for measuring pool marginal capacity costs. This work included development of the methodology and implementation of the system for quantifying LOLP-based marginal capacity costs.

Provided testimony on behalf of the investor-owned electric utilities in New York State, concerning the proper methodology to use when analyzing the cost-effectiveness of conservation programs. This methodology was adopted by the Commission and used as the basis for DSM evaluation in New York from 1982 through 1988.

Developed the functional design of a retail access settlement system and business processes for a major PJM combination utility. This design is being used to construct a software system and develop business procedures that will be used for retail settlements beginning January 1999.

Reviewed the power pool operating and interchange accounting procedure of the New York Power Pool, the Pennsylvania, New Jersey, Maryland Interconnection, Allegheny Power System, Southern Company, and the New England Power Pool as part of various consulting assignments and in connection with the development of production simulation software.

Summarized and analyzed the operational NEPOOL to examine the feasibility of incorporating NEPOOL interchange impacts with Central Maine and accounting procedure of the New England Power Pool Power Company's buy-back tariffs.

Developed and presented a two-day seminar delivered to electric industry participants in the UK (prior to privatization), outlining the structure and operation of power pools and bulk power market transactions in North America.

Benchmark analysis and FERC testimony of PGE's proposed twelve-year contract between PG&E and Electric Gen LLC (contract value in excess of $15 billion).

Responsible for NERA's overall efforts in advising New Jersey's Electric Distribution Companies on the structuring and conduct of the Basic Generation Service auctions (the 2002 auction involved $3.5 billion, and the 2003 and 2004 auctions involved over $4.0 billion).

Publications, Speeches, Presentations, and Reports

Capacity Adequacy in New Zealand's Electricity Market, published in *Asian Power*, September 18, 2003

Central Resource Adequacy Markets For PJM, NY-ISO AND NE-ISO, a report written February 2004

Ex Ante or *Ex Post*? Risk, Hedging and Prudence in the Restructured Power Business, The Electricity Journal, April 2006

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Testimony

Forums

Arkansas Public Service Commission

Federal Energy Regulatory Commission

Florida Public Service Commission

Maine Public Utilities Commission

Minnesota Public Service Commission

Nevada Public Service Commission

New York Public Service Commission

Nuclear Regulatory Commission – Atomic Safety and Licensing Board

Oklahoma Public Service Commission

Public Service Commission of Indiana

Public Utilities Commission of Ohio

Public Utilities Commission of Nevada

Public Utilities Commission of Texas

Public Utilities Commission of New Hampshire

United States District Court

United States Senate Committee on Energy and Natural Resources

Various arbitration proceedings

Clients

American Electric Power Company

Arkansas Power & Light Company

Baltimore Gas & Electric

Carolina Power & Light Company

Central Maine Power

Consolidated Edison Company of New York, Inc.

Dayton Power and Light Company

Florida Coordinating Group

Houston Lighting & Power Company

Minnesota Power and Light Company

Nevada Power Company

Niagara Mohawk Power Corporation

Northern Indiana Public Service Company

Oglethorpe Power Corporation

Pacific Gas and Electric Company

Power Authority of the State of New York

Public Service and Electric Company

Public Service Company of Oklahoma

Sierra Pacific Power Company

Southern Company Services, Inc.

Tucson Electric Power Company

Texas-New Mexico Power Company

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October 2013

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EXHIBIT B – NERA/S&L REPORT

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

NERA
Economic Consulting

Final Report

August 2, 2013

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LEGAL NOTICE

This report was prepared by NERA Economic Consulting (NERA) and by Sargent & Lundy LLC, hereafter referred to as Sargent & Lundy, expressly for NERA in accordance with Contract No. SA-27605 and in compliance with the New York Independent System Operator Code of Conduct. Neither NERA nor Sargent & Lundy nor any person acting on their behalf (a) makes any warranty, express or implied, with respect to the use of any information or methods disclosed in this report or (b) assumes any liability with respect to the use of any information or methods disclosed in this report.

I. Executive Summary

In 2003, the NYISO implemented an Installed Capacity[1] (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 the 2014/15, 2015/16 and 2016/17 Capability Years.

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 peaking plant type for each region[2].

In considering the study, the Services Tariff was the primary guide. Particularly, Section 5.14.1.2 of that Tariff section specifies that the update shall be based upon and consider the following:

[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), the New York Control Area (NYCA), and any New Capacity Zone established by NYISO. As proposed 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, which consists of G, H, and I).

- the current localized levelized embedded cost of a peaking plant in each NYCA Locality, the Rest of State, and any New Capacity Zone, to meet minimum capacity requirements;

- the likely projected annual Energy and Ancillary Services revenues of the peaking 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, 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

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

establish the Demand Curve if it was not the lowest net cost unit may lead to inefficiencies. Therefore, at the NYISO's request, we also examined the localized levelized costs and net energy and ancillary service revenues of the lowest net cost plant, 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 as the applicable peaking plant. This study examines in detail five types of units, representing four 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 represented by the LMS 100. The third technology option is industrial frame combustion turbines represented by the Siemens SGTG-5000F(5). The fourth technology evaluated in the study, and presented for informational purposes only, is a combined cycle plant represented by a Siemens SGTG-5000F(5) 1x1x1 configuration.

A review of these units showed the following:

1. The Siemens SGT6-5000F(5) is the lowest capital and highest operating cost unit, and could be constructed practically in Zones A through F. Construction of this unit in Zones A through F was determined to be practicable when limited to a one unit plant that would accept a permit restriction on annual operating hours of between 1,000 and 1,100 hours to meet the emission control standards for NO_x. This limitation would not render this unit impractical or not economically feasible.

2. The Siemens SGT6-5000F(5), however, is not a practical economically viable unit in Zones G through K. The prevalence of more severe air quality issues in this area and, correspondingly, more stringent NO_x emission requirements, eliminates the option of accepting an annual operational limit to comply with applicable emission rate limitations. The maximum number of hours that the unit could run with a operational limit for NO_x would be too low to consider the unit practical or economical in these Zones. Further, the applicable peaking plant for this area is assumed to be a dual fuel unit. Burning oil would increase NO_x emissions and further reduce the allowable operating hours. Without an economically acceptable annual operating limitation

the unit would be required to apply emission control technology to comply with specific NO_x emission rate limits. While Selective Catalytic Reduction (SCR) is the post-combustion emission control technology that is most widely utilized to control NO_x for combined cycle plants is at this time it is unproven as a control technology for the large frame gas turbines. That leaves the LMS100 and the Wartsila reciprocating engines. 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 for Zones G to K as defined by the Services Tariff.

3. The Siemens SGT6-5000F(5) combined cycle plant would result in a lower Demand Curve in the locations examined other than NYC and the Capital and Central regions. 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 a cycling mode and 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 current requirement of being 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.

The LMS100 with an SCR was selected as the peaking unit for the New Capacity Zone proposed as Load Zones G-J (G-J Locality), NYC and LI. The NYISO's proposal for a New Capacity Zone also will propose to redefine ROS so that the NYCA ICAP Demand Curve would be based on Load Zones A-F. We show costs herein for a location in Zone C and one in Zone F, and recommend that the Zone F curve be used because it has the lower reference value.. We show costs for the new capacity Zones based on a Rockland County and Dutchess County location and recommend that the Rockland County location be used because it has the lower reference point. 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.

Table I-1

Demand Curve Values at Reference Point:

Values for Capacity Years 2013/2014 and 2014/2015

	2010 DC Value for 2013/2014 2013 dollars/kW-year			*2013 Update for 2014/2015 2014 dollars/kW-year*		
	Annual Fixed Cost	Energy and AS Net Revenues	Net Costs	Annual Fixed Cost	Energy and AS Net Revenues	Net Costs
ROS Frame 7	123.80	27.46	**96.34**	N/A	N/A	**N/A**
Zone C"SGT6-5000 (F" Class frame) GT	N/A	N/A	**N/A**	106.10	15.48	**90.62**
Zone F–"SGT-5000(F" Class frame) GT	N/A	N/A	**N/A**	107.29	18.48	**88.81**
NYC LMS100	288.29	97.26	**191.02**	299.54	54.50	**245.04**
HV Dutchess LMS100	N/A	N/A	**N/A**	220.15	47.12	**173.03**
HV Rockland LMS100	N/A	N/A	**N/A**	224.80	53.06	**171.75**
LI LMS 100	259.39	151.82	**107.57**	247.62	114.64	**132.98**
Zone C CCGT	N/A	N/A	**N/A**	194.24	59.88	**134.35**
Zone F CCGT	N/A	N/A	**N/A**	205.54	67.15	**138.40**
NYC CCGT	N/A	N/A	**N/A**	482.46	100.84	**381.62**
HV Dutchess CCGT	N/A	N/A	**N/A**	253.49	79.90	**173.58**
HV Rockland CCGT	N/A	N/A	**N/A**	257.62	101.23	**156.39**
LI CCGT	N/A	N/A	**N/A**	287.06	190.56	**96.49**

*The 2010 ROS peaking plants consisted of two Frame 7 peaking units with a 1243 operating hour limit. The 2013 ROS peaking plant consists of one F Class frame peaking unit with a 1000-1100 operating hour limit.

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 28% and 24%, 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 efficient 500 MW 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 intertie

(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 the NYISO and PJM. Additionally, fixed costs in NYC have increased by about $11 per kW year, while those in LI have declined by about $12 per kW year.

The ROS Demand Curve drops by approximately seven percent. This is the effect of an approximately 13 percent decrease in fixed cost which is partly offset by lower net energy revenues. 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 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.

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.

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

MS100

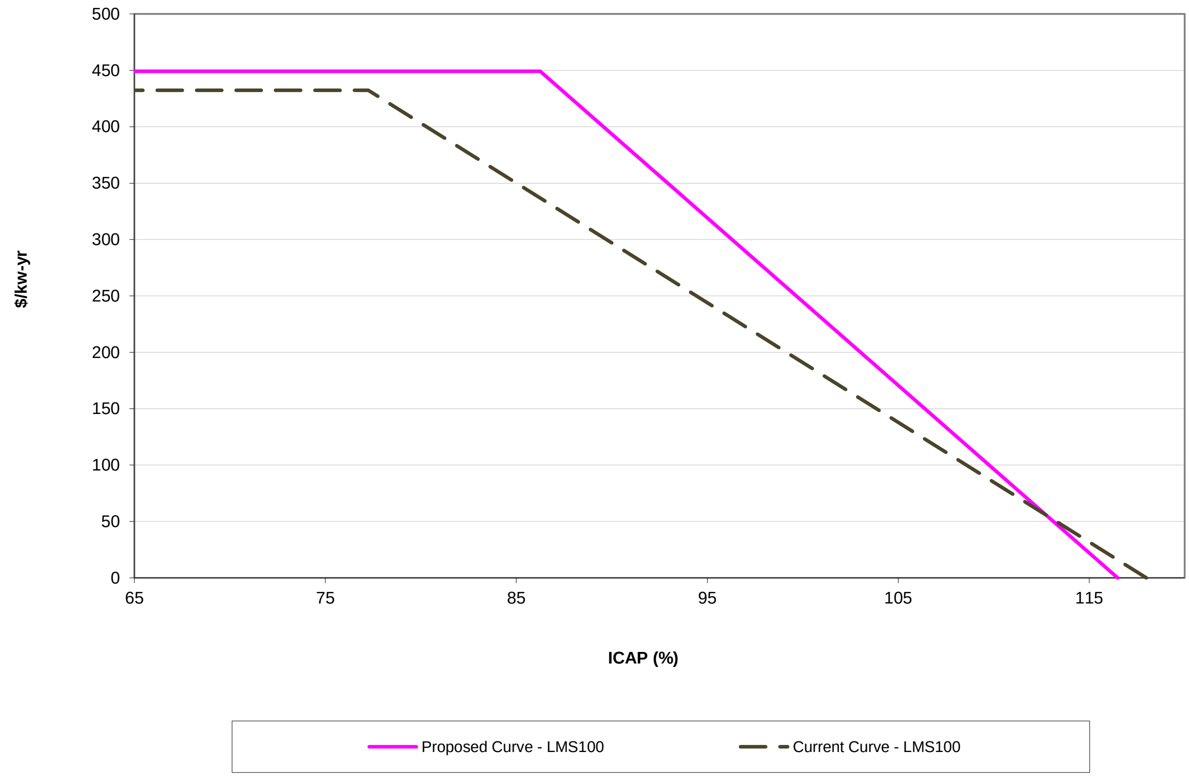


Figure I-2 — Proposed Demand Curves - Long Island

LMS100

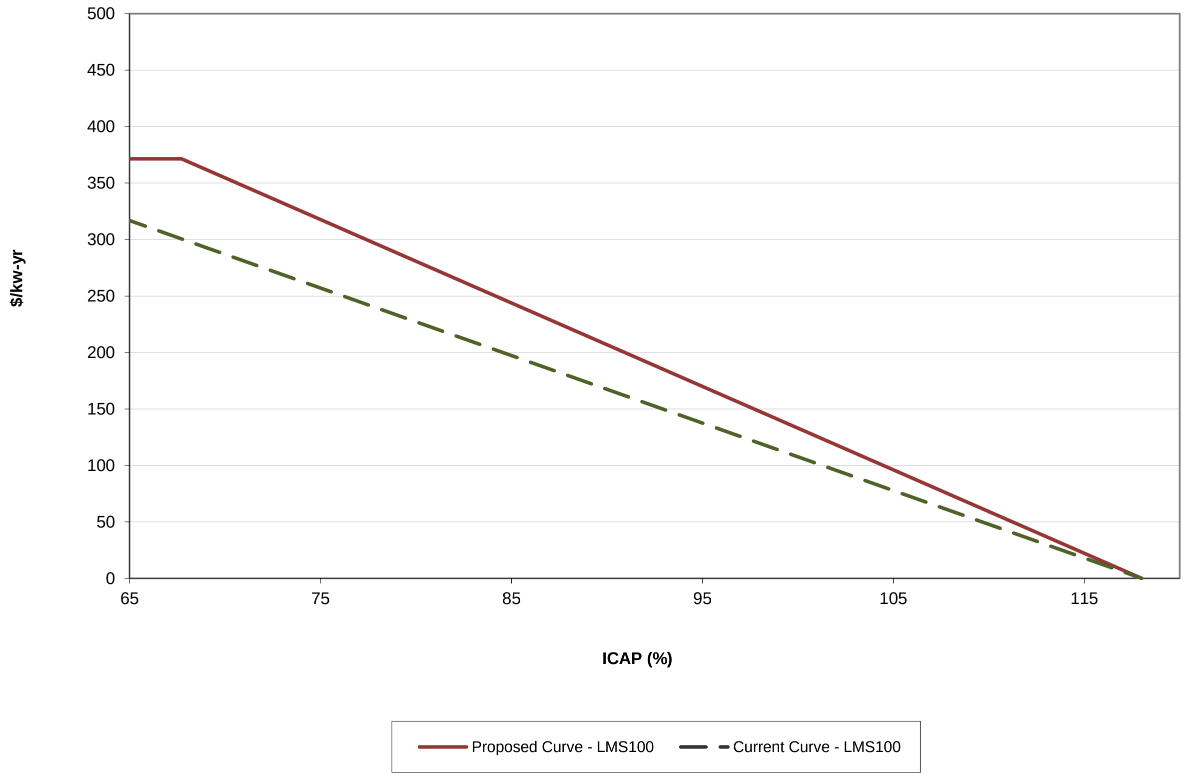


Figure I-3 — Proposed Demand Curves - G-J (Rockland)

LMS100

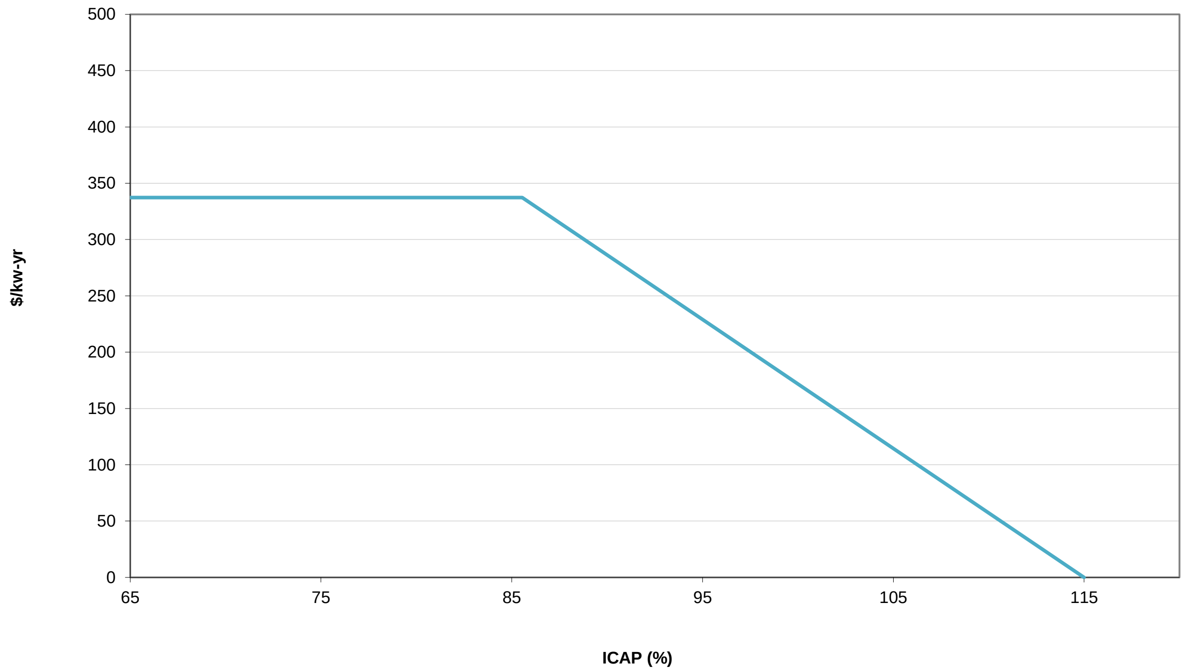
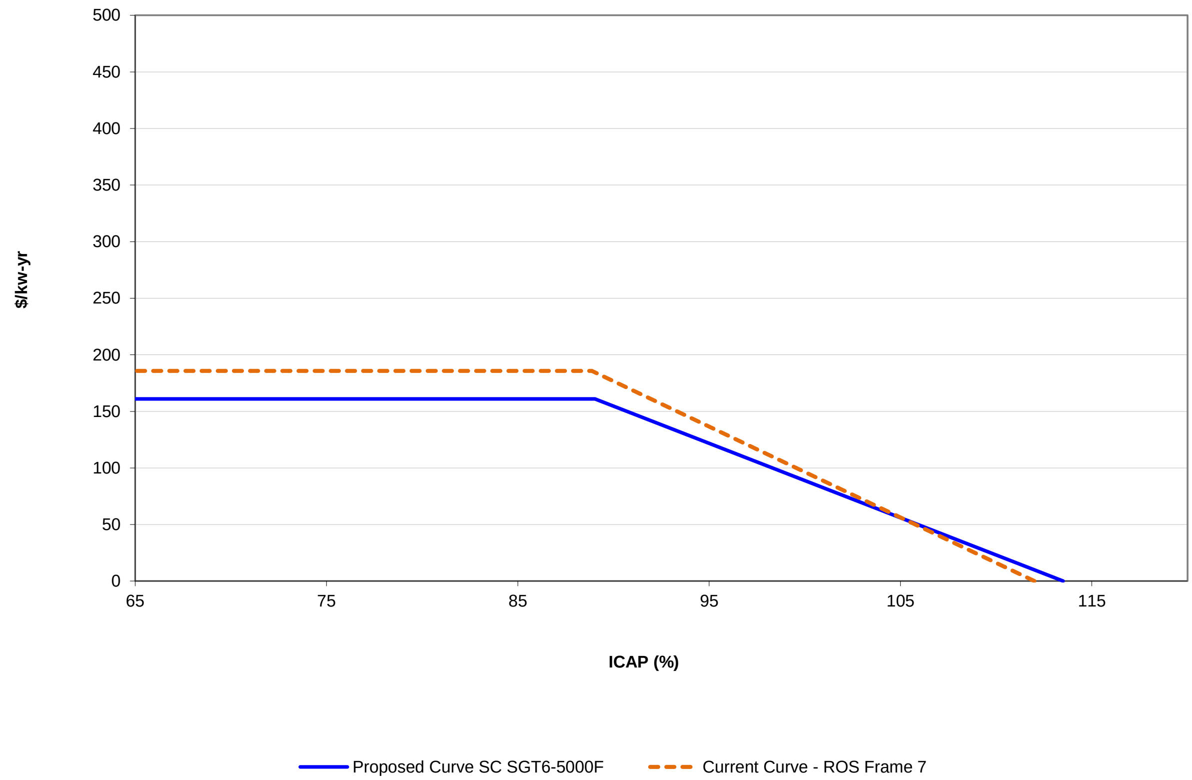


Figure I-4 — Proposed Demand Curves - Capital Siemens SGT-5000(F)



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 the 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. The 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

[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

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 may 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%, 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). NERA believes that 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 the best course to ensure 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 to model assumptions. It is also possible that should the 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 the NYISO revisits the FTI Study[5] and 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

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

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 a zero crossing point for Zones G to J, the proposed NCZ.

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.[6] 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."[7]

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

[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] Services Tariff, Section 5.14.1(b)

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 operating costs. Section A of this section describes the screening analysis and results. The analysis has not considered Special Case Resources.[8]

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.

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:

[8] The 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.

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 CO_2 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 simple or 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 (SCR) technology for NO_X control is problematic because exhaust gas temperatures in simple-cycle mode exceed 850°F. Past experience with SCR control on simple cycle frame units have shown that such high exhaust gas temperatures irreversibly damage the catalyst. 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 with an SCR 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 NOx 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 NOx combustion is available on aeroderivative units to reduce the amount of water used in the NOx 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 NOx 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) from the LMS 100 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 NOx combustion (the PA model) and dry low

NOx 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 NOx, 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 four 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 Technologies[9]

Technology	Combined Cycle with "F" Class Frame Siemens SGT6-5000F(5) (1x1x1)[10] with SCR	Simple Cycle Turbine "F" Class Frame Siemens SGT6-5000F(5) without SCR	Simple Cycle Turbine Aeroderivative LMS100 PA with SCR	Reciprocating Internal Combustion Engine 18V50DF/18V50SG with SCR
Number of Units	1	1	2	12
Net Capacity of Units (ICAP MW, Degraded)	301.7 - 304.9	205.4 - 206.5	183.6 - 186.3	188.3 - 197.9
Total Cost ($M)	401 - 618	146 - 148	248 - 342	363 - 505
Total Cost ($/kW)	1,330 – 2,034	711 - 718	1,332 – 1,858	1,836 – 2,683
Heat Rate (Btu/kWh HHV) – winter	7,095	10,250	9,125	8,512
Pressure Ratio	18.9:1	18.9:1	43.3:1	N/A
Exhaust Temperature of Gas Turbine or engine (°F)	1,106	1,106	774	707
Land Area (acres)	20	10	10	10
Water Use (MGD)	2.3	<0.1	0.9	<0.1
Minimum Load for one unit (ICAP MW, degraded)	206	133	60.5	16[11]
Heat Rate at Minimum Load (Btu/kWh HHV)_	7,639	11,593	10,490	N/A

Appendix 1 shows more detailed information on the cost and performance characteristics of the Siemens SGT6-5000F(5) in combined cycle and simple cycle (without SCR), GE LMS100, and Wartsila 18V50DF/18V50SG technologies. The following section addresses the impact of emissions limitations on technology choice.

[9] 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.

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

[11] 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 four technologies are subject to New Source Review pre-construction permit regulations and Title V operating permit regulations in 6 NYCRR Part 231 and Subpart 201.6, respectively.[12]

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, which 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 emissions 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)

[12] 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 YYYY – Stationary Combustion Turbine
- Subpart ZZZZ – Reciprocating Internal Combustion Engine;

- New Source Review (6 NYCRR Part 231); and
- New York State CO_2 Performance Standards (6 NYCRR Part 251).

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.

NYDEC has recently adopted performance standards regulating CO_2 emissions from major electric generating facilities. The CO_2 emission standards became effective July 12, 2012 and are codified in 6 NYCRR §251. A major electric generating facility is defined in Part 251 as an electric generating facility (i.e., a facility that sells power to the electric grid and that utilizes boilers, combustion turbines, waste to energy sources, and/or stationary internal combustion engines to produce electricity) with a generating capacity of at least 25 megawatts (MW). All new electric generating facilities must comply with the emission limits detailed in Table II-2. All technology options analyzed in this study will readily meet the 6 NYCRR § Part 251 standards.

Table II-2 NYCRR Part 251 CO_2 Emission Limits for New Major Electric Generating Facilities (≥ 25 MW)

Major Electric Generating Facility Type(1)	CO_2 Emission Limit(2)
Boilers that fire >70% fossil fuel	925 lbs CO2/MWh-gross or 120 lbs CO2/MMBtu
Combined-Cycle Combustion Turbines	925 lbs CO2/MWh-gross or 120 lbs CO2/MMBtu
Simple-Cycle Combustion Turbines	1450 lbs CO2/MWh-gross or 160 lbs CO2/MMBtu
Stationary Internal Combustion Engines that fire gaseous fuel only	925 lbs CO2/MWh-gross or 120 lbs CO2/MMBtu
Stationary Internal Combustion Engines that fire liquid fuel or liquid and gaseous fuel simultaneously	1450 lbs CO2/MWh-gross or 160 lbs CO2/MMBtu

1) Emission sources directly attached to a gasifier (defined as an emission source that converts a hydrocarbon feedstock into a fuel) are exempt from these CO2 emission limits (subpart 251.3).

2) Emission limits are measured on a 12-month rolling average basis, calculated by dividing the annual total of CO2 emissions over the relevant 12-month period by either the annual total (gross) MW generated or the annual Btu input over the same 12-month period (subpart 251.3).

NSR pre-construction review/permitting requirements apply to new major sources of regulated NSR air pollutants.[13] A stationary source is classified as major if it directly emits, or has the potential to emit[14] a designated amount of regulated air pollutant or carbon dioxide equivalents (CO_2e) of which the amount depends on the attainment area designation and source type.[15]

Currently, New York State has areas designated as non-attainment for ozone, PM2.5, and PM10. The ozone and PM2.5 non-attainment areas are shown in the figures below. The only county designated as a PM10 non-attainment area is New York County.[16] In addition, volatile organic carbon (VOC) and nitrogen oxides (NOx) are treated as non-attainment contaminants statewide as precursors of ozone due to New York State being within the Ozone Transport Region.[17]

[13] Regulated NSR air pollutants include: carbon monoxide (CO), lead (Pb), nitrogen oxides (NOx), sulfur dioxide (SO_2), volatile organic compounds (VOC), and particulate matter with an aerodynamic diameter less than 10 microns (PM_{10}). Regulated NSR contaminant defined in 6 NYCRR §231-4(44).

[14] Potential to emit is based upon operation of the plant for 8,760 hours per year, unless federally enforceable operational limits are accepted as permit conditions.

[15] Major stationary source defined in 6 NYCRR §201-2(21).

[16] Non-attainment area defined in 6 NYCRR §200-1(av).

[17] 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 NOx are treated as nonattainment contaminants statewide as precursors of ozone. PM2.5 precursors, SO_2 and NOx, are treated as nonattainment contaminants in New York State's PM2.5 nonattainment area." Ozone Transport Region defined in 6 NYCRR §200.1(bd).

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

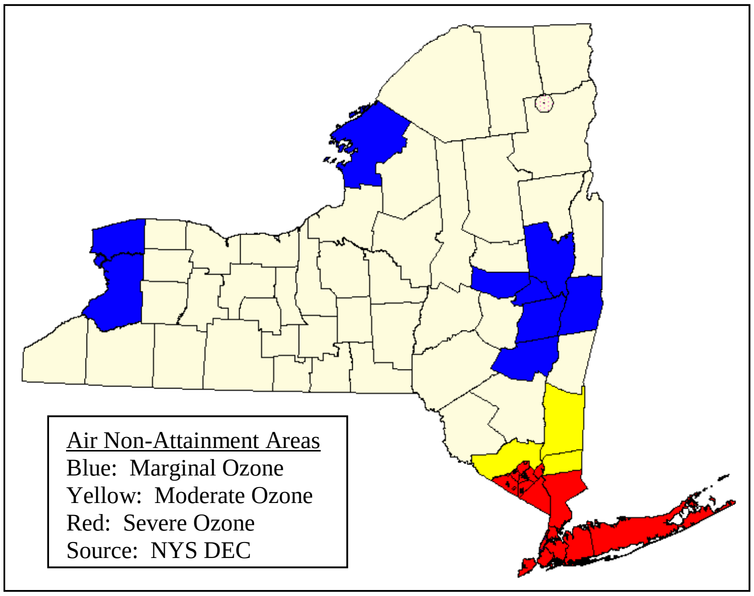
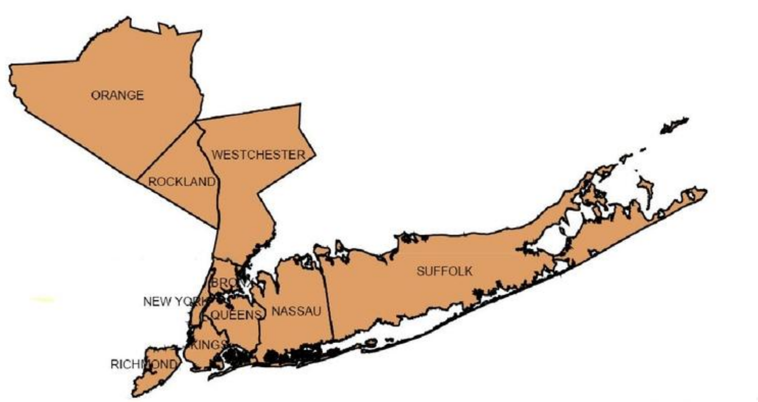


Figure II-2 — PM2.5 Non-attainment Areas in New York State



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.[18] 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. Table II-3 provides major source thresholds in New York State for new combustion turbines and RICE units within each attainment area designation anticipated in the near-term.[19]

Table II-3 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

	Simple-Cycle CT or RICE			Combined-Cycle CT		
Regulated Air Pollutant	**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
SO2	≥ 250	≥ 250	≥ 250	≥ 100	≥ 100	≥ 100
PM10	≥ 250	≥ 250	≥ 250	≥ 100	≥ 100	≥ 100
PM2.5	≥ 250	≥ 250	≥ 250	≥ 100	≥ 100	≥ 100
CO	≥ 250	≥ 250	≥ 250	≥ 100	≥ 100	≥ 100
CO2e	≥ 100,000	≥ 100,000	≥ 100,000	≥ 100,000	≥ 100,000	≥ 100,000

All four 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. In the 2010 demand curve reset process CO_2e was not a regulated criteria pollutant, but all the proposed plants, except the technology chosen for rest of state were major sources, and as such subject to NSR permitting

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

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

requirements. The Rest Of State unit, which was a simple cycle frame gas turbine without SCR, was not treated as major source because its expected annual emissions was less than the major source threshold.

There are two types of NSR permitting requirements: (1) Prevention of Significant Deterioration (PSD) permits and (2) Non-attainment NSR (NNSR) permits.[20] 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:

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;[21] 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.[22] ERCs must represent the same regulated air pollutant requiring the ERC and derive from within the non-attainment area in which the

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

[21] 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."

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

proposed new facility will be located.[23] ERCs of VOC and NOx for facilities located in an attainment area within the Ozone Transport Region may be obtained from any location within the Ozone Transport Region, including an ERC from another state in the Ozone Transport region, provided that an interstate reciprocal trading agreement is in place and a specific contribution demonstration has been performed according to the NYDEC Guidelines on Dispersion Modeling Procedures for Air Quality Impact Analysis.[24] 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.[25]

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;
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 National Ambient Air Quality Standards (NAAQS) or PSD increments;
3. conduct a Best Available Control Technology (BACT) review and install emission control technologies that represent BACT;[26] 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

[23] 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 are of the proposed facility.

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

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

[26] 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."

general commercial, residential, industrial, and other growth associated with the proposed new facility.

Table II-4 provides PSD significant emissions thresholds in New York State for all four technologies within each attainment area designation anticipated in the near-term.[27]

Table II-4 PSD Significant Emissions Thresholds for All Four 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
NOx	≥ 2.5	≥ 40	≥ 40
SO2	≥ 40	≥ 40	≥ 40
PM10	≥ 15	≥ 15	≥ 15
PM2.5	≥ 10	≥ 10	≥ 10
CO	≥ 100	≥ 100	≥ 100
CO2e	≥ 100,000	≥ 100,000	≥ 100,000

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 CO_2 Performance Standard).

Based on preliminary emissions calculations for each of the four technologies, the following lists the potential NSR permitting review outcomes. Simple- and combined-cycle combustion turbines will likely trigger PSD/BACT for CO_2e and NOx emissions, and may trigger PSD/BACT for VOC emissions and NNSR/LAER for NOx emissions in severe ozone non-attainment areas. RICE units will likely trigger PSD/BACT for CO_2e and NOx emissions and NNSR/LAER for VOC emissions, and may trigger NNSR/LAER for NOx emissions in severe ozone non-attainment areas. All

[27] See, 6 NYCRR §231-13 Tables and Emission Thresholds.

technologies meet NYCRR Part 251 CO2 Emission Limits for New Major Electric Generating Facilities.

New units subject to NSR are required to install air pollution controls to 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-NOx combustors, water injection) and post-combustion controls (i.e., Selective Catalytic Reduction (SCR)) to reduce NOx 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*., CO_2e). No add-on CO_2 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 Table II-5.

Table II-5 Potential LAER/BACT Requirements for Natural Gas-Fired Simple- and Combined-Cycle Combustion Turbines[28]

Regulated Air Pollutant	LAER	BACT
NOx	Selective Catalytic Reduction < 2.5 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
PM10	N/A	low ash fuel 0.005 – 0.01 lb/MMBtu
CO_2e	N/A	cycle efficiency & NYCRR Part 251

Combustion turbine projects subject to PSD review for GHG emissions may be required to evaluate the availability of more efficient combustion turbine alternatives. The first step of a BACT analysis

[28]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.

requires the identification of all control technologies, including inherently lower-emitting operating processes/practices, add-on controls, and combinations of the two. The inclusion of evaluating inherently lower-emitting processes has raised debate concerning the evaluation of more efficient natural gas-fired electrical generating unit configurations (e.g., aeroderivative compared to “frame” combustion turbines and combined-cycle compared to simple-cycle operation). The NSR Workshop Manual[29] states that “[h]istorically, EPA has not considered the BACT requirement as a means to redefine the design of the source when considering available control alternatives.” For example, applicants proposing to construct a coal-fired generating unit were not required to consider natural gas-fired turbines as part of their BACT analysis; however, the NSR Workshop Manual goes on to state that “there may be instances where, in the permit authority’s judgment, the consideration of alternative production processes is warranted and appropriate for consideration in the BACT analysis.” These statements have led to much debate concerning what constitutes “redefining the source.” To date, the argument that requiring a change from one proposed natural gas-fired configuration to another (e.g., frame to aeroderivative) in Step 1 of the BACT analysis, is considered redefining the source has not been adjudicated, nor has it been addressed in a permit application to date.

As discussed in Section II B, the SGT6-5000F(5) in simple cycle operation with SCR technology was not evaluated due to problems with controlling exhaust temperature for inclusion of SCR technology. To operate the SGT6-5000F(5) in simple cycle without an SCR, operating hours would need to be restricted below the threshold that would trigger LAER/BACT requirements (i.e., selective catalytic reduction). The PSD significant emissions thresholds that would trigger NOx BACT requirements for new SGT6-5000F(5) in simple cycle operation are 2.5 tons per year or more in severe ozone non-attainment areas and 40 tons per year or more in all other areas of New York State (see, Table II-4). Table II-6 and II-7 provide operating hour thresholds for a single SGT6-5000F(5) unit operating in simple cycle operation firing natural gas and ultra-low sulfur diesel fuel, respectively. A simple cycle SGT6-5000F(5) unit operating without SCR or other post combustion controls would be equipped with dry-low NO_x combustion controls for natural gas firing.

[29] New Source Review Workshop Manual Prevention of Significant Deterioration and Nonattainment Area Permitting, Draft October 1990 Section B.13.

Table II-6 — Annual Operating Hour Restrictions for Natural Gas-Fired Simple-Cycle Frame Combustion Turbine to Avoid LAER/BACT Requirements for NOx Emissions

Control Area Load Zone	PSD Significant Emissions Thresholds for NOx (tons per year)	NOx Operating Hour Threshold
Zone F (Albany County)	40	1,075 hours
Zone C (Onondaga County)	40	1,058 hours
Zone G (Dutchess County)	40	1,056 hours
Zone G (Rockland County)	2.5	66 hours
Zone J (New York City)	2.5	66 hours

Table II-7 — Annual Operating Hour Restrictions for Ultra-Low Sulfur Diesel Oil-Fired Simple-Cycle Frame Combustion Turbine to Avoid LAER/BACT Requirements for NOx Emissions

Control Area Load Zone	PSD Significant Emissions Thresholds for NOx (tons per year)	NOx Operating Hour Threshold
Zone G (Dutchess County)	40	266 hours
Zone G (Rockland County)	2.5	14 hours
Zone J (New York City)	2.5	14 hours

The thresholds shown in Tables II-6 represent the estimated maximum annual operating hours for the SGT6-5000F(5) in simple cycle without an SCR for operation on natural gas only. As will be discussed in Section II F, operation on a single fuel--natural gas--is assumed only in Zones C and F. Section III of this report shows that the expected annual operating hours of the SGT6-5000F(5) in simple cycle without an SCR operating on natural gas only is below the thresholds shown in Table II-6.

The thresholds shown in Table II-7 represent the estimated maximum annual operating hours for the SGT6-5000F(5) in simple cycle without an SCR for operation with dual fuels--natural gas and ultra-low sulfur diesel--which is assumed for Zones G, J and K.[30] Based on the Section III analysis, we expect that the annual operating hours of the SGT6-5000F(5) in simple cycle without an SCR operating on dual fuels is greater than the thresholds for Zones G, J and K. Consequently, the SGT6-5000F(5) in simple cycle without an SCR operating on dual fuels in Zones G, J and K has not been evaluated.

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 NOx 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 CO_2 capture and sequestration control technologies have been required to meet the GHG BACT requirements. All RICE units must comply with project-specific NSPS for NOx, 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 NO_2 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. This evaluation did not include specific operating restriction stipulations; however, potential operating restrictions should not negatively impact the permitting process.

D. Cap-and-Trade Program Requirements

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

- CO_2 Budget Trading Program (6 NYCRR Part 242); and
- Clean Air Interstate Rule (CAIR) Trading Program
    - CAIR NOx Ozone Season Trading Program (6 NYCRR Part 243)

[30] The threshold number of hours for operation on ultra-low sulfur diesel fuel in Zone K is expected to be the same as shown for Zone J in Table II-6.

- CAIR NOx Annual Trading Program (6 NYCRR Part 244)
- CAIR SO_2 Trading Program (6 NYCRR Part 245).

In general, the CO_2 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.[31] 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 has committed to state regulations that will cap and then reduce the amount of the CO_2 that electrical generating facilities are allowed to emit. CO_2 allowances are obtained through a CO_2 Allowance Auction system and are traded using CO_2 Budget Trading Programs. The latest CO2 Allowance Auction, held on July 5, 2013, sold 38,782,076 CO2 allowances with a clearing price of $3.21. Allowances sold represent 100% of the allowances offered for sale by the nine states.

Owners/operators of each CO_2 budget source and CO_2 budget units at the source will be required to obtain CO_2 allowances no less than the total CO_2 emissions from the CO_2 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 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 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

[31] See, NYCRR §242-1.4.

generator with a nameplate capacity of equal to or greater than 15 MW producing electricity for sale.[32]

CO_2, NOx, and SO_2 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, 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-

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

#52. NYDEC Policy CP-52 seeks a performance goal of dry closed-cycle cooling for all new industrial facilities sited in the marine and coastal district and the Hudson River up to the Federal Dam in Troy irrespective of the amount of water they would withdraw for cooling if they were to use a wet closed-cycle cooling system.[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 the remaining locations. All technologies must also comply with the requirements of the federal Clean Water Act Section 316(b) for cooling water intake structures.

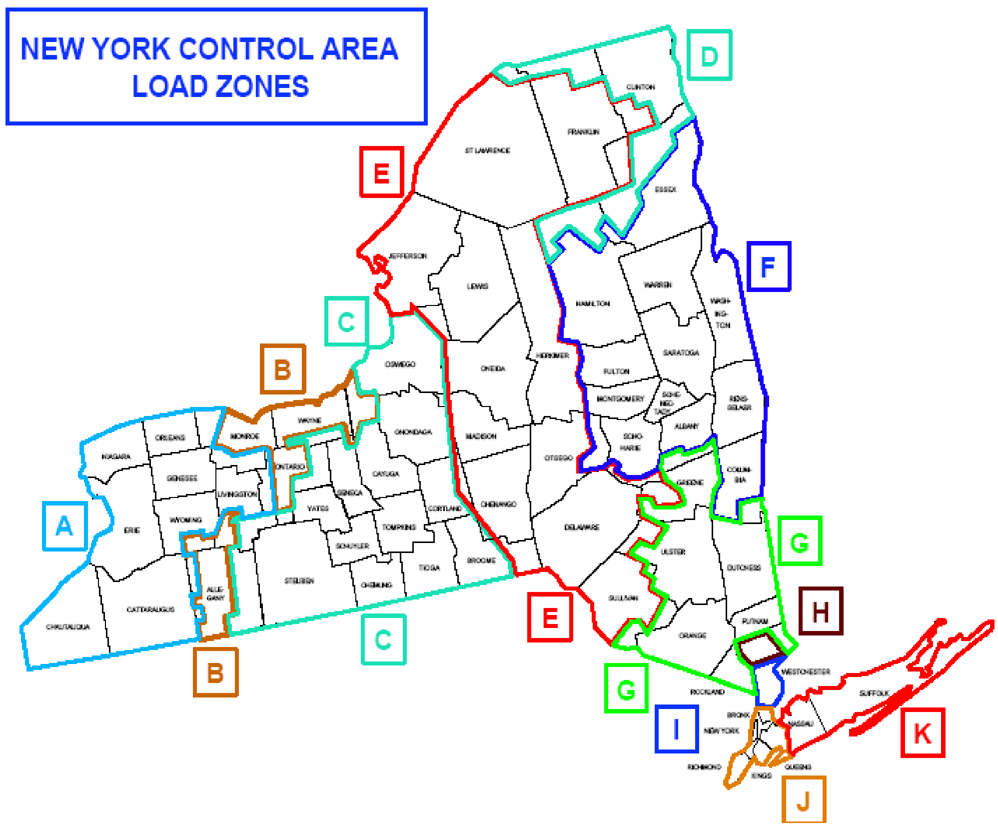
F. Construction Schedule and Costs

Cost estimates were prepared for the construction of the Siemens SGT6-5000F(5) combined cycle, the simple cycle General Electric LMS100 aeroderivative, and the Wartsila 18V50 reciprocating internal combustion engine (RICE) in each of five New York load zones: C, F, G, J, and K, and the SGT6-5000F(5) in simple cycle without an SCR in Zones C and F. 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.

[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 Chuck Nieder, Steam Electric Unit Leader, Bureau of Habitat, NYDEC, April 30, 2013.

Figure II-3 — Map of New York Control Area Load Zones



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 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 SGT6-5000F(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, and for the Siemens SGT6-5000F(5) in simple cycle without an SCR (1 unit) in Zones C and F.

Selective Catalytic Reduction is a post-combustion control technology in which injected ammonia reacts with NOx 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 NOx emission reduction is a function of the catalyst volume, ammonia-to-NOx (NH_3/NOx) 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 NH_3/NOx 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 NOx 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. As discussed in Section II B, the SGT6-5000F(5) in simple cycle operation with SCR technology was not evaluated due to problems with controlling exhaust temperature for inclusion of SCR technology.

A 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 + $\frac{1}{2}O_2 \rightarrow CO_2$. 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-1. 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. Recognizing that the size of brownfield sites also is limited, the area of the combined cycle in Zone J was reduced from 20 acres, as shown in Table II-1, to 15 acres. In addition, costs were included to raise the Zone J brownfield site 3.5 feet to address recent changes in floodplain zoning by the Federal Emergency Management Agency[35] and in New York City building codes[36] as a result of Hurricane Sandy in 2012.

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.

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[35]Federal Emergency Management Agency, Best Available Flood Hazard Data, accessed July 12, 2013, http://fema.maps.arcgis.com/home/webmap/viewer.html?webmap=2f0a884bfb434d76af8c15c26541a545

[36] Notice of Adoption of Emergency Rule Relating to the Level Above the Base Flood Elevation to Which New, Substantially Damaged or Substantially Improved Buildings That Are Located in Areas of Special Flood Hazard Must be Designed and Constructed, January 31, 2013, Table 7-1.

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.[37] 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.[38] Consolidated Edison and National Grid jointly operate the New York Facilities System (NYFS), which delivers gas to core customers and electric generators in New York City and Long Island. While a new generator could request a direct interconnect into New York City or Long Island we are not aware of any generator ever having done so, and we therefore assume any new generator will interconnect to the NYFS and be subject to the dual fuel requirements of the Local Distribution Companies' tariffs. New entrants locating outside of the NYFS have the option of connecting directly to interstate gas pipelines, but recently installed and proposed gas-fired generating units in and around New York City have opted for or announced they will both directly interconnect to the interstate pipeline and install dual fuel capability.[39] Given also that obtaining new firm gas transportation would be expected to be expensive for a generating unit without a high capacity factor, a new peaking unit would realistically choose dual fuel capability over primary firm pipeline capacity. For these reasons, dual fuel capability has been assumed for Zones G, J and K. Firing only with natural gas was assumed for the balance of the NYCA.

In Zone J, Consolidated Edison requires that dual fuel units be capable of switching from natural gas to ULSD in 45 seconds.[40] We understand that the LMS100 and Wartsila 18V50DF

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

[38] 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.

[39] For example, Bayonne Energy Center (in service) and CPV Valley (in the interconnection queue).

[40] Communication from NYISO, April 11, 2013.

technologies have this capability. We increased the estimated cost of the combustion turbines for the combined cycle alternative by 2% to account for adding this capability.

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.[41] 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 other zones.[42] 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.

[41]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 February 2013.

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

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 305 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 that no SDUs for the capacity levels of the four technologies.

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.

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 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 combined cycle SGT6-5000F(5) in Zones C, 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.[43] For dual fuel units, ERCs include 30 days per year of Ultra Low Sulfur Diesel fuel operation and 11 months of natural gas operation. No ERCs are required for the simple cycle SGT6-5000F(5) without SCR.

- 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 and simple cycle SGT6-5000F(5) without SCR, 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 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

[43] 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.

payment of monthly operating expenses. On the basis of recent independent power projects, these costs have been estimated as 1% of direct capital costs plus the cost of an inventory of Ultra Low Sulfur Diesel fuel equivalent to 3 days of full load operation priced at $20/mmBtu.

Capital investment costs for each location and combustion turbine option are summarized below in Table II-8.

Table II-8 — Capital Investment Costs for Greenfield Site (2013 $)

	2xGE LMS100 PA	1x1x1 Siemens SGT6-5000(F)	12xWartsila 18V50	1xSiemens SGT6-5000(F)
Zone C - Syracuse				
Direct Costs	215,173,000	331,986,000	310,535,000	126,675,000
Owner's Costs	19,796,000	31,774,000	33,871,000	11,654,000
Financing Costs During Construction	10,976,000	34,238,000	15,874,000	6,461,000
Working Capital and Inventories	2,152,000	3,320,000	3,105,000	1,267,000
Total	248,097,000	401,318,000	363,385,000	146,057,000
Net Degraded ICAP MW	186.25	301.67	197.94	205.40
$/kW	$1,332	$1,330	$1,836	$711
Zone F - Albany				
Direct Costs	228,078,000	352,005,000	315,468,000	128,659,000
Owner's Costs	20,983,000	34,764,000	33,520,000	11,837,000
Financing Costs During Construction	11,634,000	36,403,000	16,085,000	6,563,000
Working Capital and Inventories	2,281,000	3,520,000	3,155,000	1,287,000
Total	262,976,000	426,692,000	368,228,000	148,346,000
Net Degraded ICAP MW	183.6	302.03	188.30	206.50
$/kW	$1,432	$1,413	$1,955	$718

	2xGE LMS100 PA	1x1x1 Siemens SGT6-5000(F)	12xWartsila 18V50
Zone G - Hudson Valley (Dutchess County)			
Direct Costs	244,839,000	386,104,000	344,213,000
Owner's Costs	23,391,000	39,075,000	37,987,000
Financing Costs During Construction	12,529,000	40,018,000	17,616,000
Working Capital and Inventories	5,046,000	7,141,000	5,846,000
Total	285,805,000	472,338,000	405,662,000
Net Degraded ICAP MW	184.402	302.78	188.30
$/kW	$1,550	$1,560	$2,154
Zone G - Hudson Valley (Rockland County)			
Direct Costs	251,140,000	401,319,000	353,487,000
Owner's Costs	23,970,000	40,475,000	38,842,000
Financing Costs During Construction	12,851,000	41,582,000	18,082,000
Working Capital and Inventories	5,109,000	7,293,000	5,939,000
Total	293,070,000	490,669,000	416,350,000
Net Degraded ICAP MW	184.402	302.78	188.30
$/kW	$1,589	$1,621	$2,211

	2xGE LMS100 PA	1x1x1 Siemens SGT6-5000(F)	12xWartsila 18V50
Zone J - NYC			
Direct Costs	290,532,000	503,588,000	426,954,000
Owner's Costs	30,778,000	53,737,000	49,519,000
Financing Costs During Construction	15,009,000	52,456,000	21,960,000
Working Capital and Inventories	5,519,000	8,339,000	6,711,000
Total	341,838,000	618,120,000	505,144,000
Net Degraded ICAP MW	184.00	303.89	188.30
$/kW	$1,858	$2,034	$2,683
Zone K - Long Island			
Direct Costs	269,642,000	452,483,000	393,337,000
Owner's Costs	26,825,000	45,431,000	42,056,000
Financing Costs During Construction	13,848,000	46,864,000	20,067,000
Working Capital and Inventories	5,321,000	7,833,000	6,369,000
Total	315,636,000	552,611,000	461,829,000
Net Degraded ICAP MW	185.516	304.87	188.30
$/kW	$1,701	$1,813	$2,453

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-9.

Table II-9 — Fixed O&M Assumptions (2013 $)

	Albany	Syracuse
	Simple Cycle SGT6-5000F(5)	Simple Cycle SGT6-5000F(5)
Average Labor Rate, incl. Benefits ($/hour)	$56.51	$52.33
Operating Staff (full-time equivalents)	5	5
Maintenance Staff (full-time equivalents)	3	3
Routine Materials and Contract Services	$308,000	$300,000
Administrative and General	$335,000	$326,000

	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

	Albany	Syracuse
	Simple Cycle SGT6-5000F(5)	Simple Cycle SGT6-5000F(5)
Average Labor Rate, incl. Benefits ($/hour)	$56.51	$52.33
Operating Staff (full-time equivalents)	5	5
Maintenance Staff (full-time equivalents)	3	3
Routine Materials and Contract Services	$308,000	$300,000
Administrative and General	$335,000	$326,000

	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

In addition to the Fixed O&M assumptions in Table II-9, an allowance has been made for dual fuel units while performing required tests operating on ultra-low sulfur diesel (ULSD) fuel. With the cost of natural gas at approximately $4/mmBtu and the cost of ULSD fuel at approximately $20/mmBtu, operating losses during required tests are not negligible. We assume that a dual fuel unit would be operated on ULSD fuel for 30 hours during commissioning, for one hour per month to demonstrate capability, and for 15 hours every five years for stack tests required by the unit's air permit. The operating losses during commissioning have been included in the capital cost estimates in Table II-8 and Tables A-4 through A-7. The operating losses during monthly capability and quintennial stack tests have been included in fixed O&M cost estimates in Table A-3.

Other fixed operating costs are described below and summarized in Table II-10.

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-10.

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).[44]

LI: Each town in Suffolk County sets its own property tax rate.[45] 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. However, as a payment in lieu of taxes (PILOT) can be negotiated from a local Economic development Authority, a PILOT rate of 0.75% was used based upon a review of PILOT agreements.

[44] 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).

[45] **http://www.osc.state.ny.us/localgov/orptbook/taxrates.htm**

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), county websites, and several examples of Payment in Lieu of Taxes (PILOT) agreements. From the wide 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, and the example PILOT agreements, a 0.75% effective was chosen .

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.[46] 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 0.60% 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-10 — Other Fixed Operating Cost Assumptions (2013 $)

	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 - Simple Cycle SGT6-5000F(5)	N/A	N/A	N/A	10.00
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%	0.75%	0.75%	0.75%
Assessment Ratio	45.00%	100.00%	100.00%	100.00%
Effective Property Tax Rate	4.63%	0.75%	0.75%	0.75%
Insurance Rate	0.60%	0.60%	0.60%	0.60%

* 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.

[46] 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.

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-11.

Table II-11 — Variable O&M Assumptions (2013 $)*

	All Regions	All Regions	ROS	All Regions
	2 x LMS100 PA	1 x 1 x 1 SGT6-5000F(5)	Simple Cycle SGT6-5000F(5)	12 Units - 18V50
Major Maintenance Interval (Operating Hours)	50,000	48,000	48,000	n/a
Major Maintenance Interval (Factored Starts)	n/a	2,400	2,400	n/a
Cost of Parts Required for Complete Major Maintenance Interval:				
- Combustion Turbines (per turbine)	13,500,000	20,200,000	20,200,000	-
- Balance of Plant	-	3,800,000	-	-
Labor-Hours Required for Complete Major Maintenance Interval:				
- Combustion Turbines (per turbine)	14,000	15,000	15,000	-
- Balance of Plant				
Unscheduled Maintenance ($/MWh)	0.86	0.26	-	0.34
Routine Maintenance ($/MWh)	-	-	-	1.94 to 2.37
Lube Oil ($/MWh)	-	-	-	1.24
SCR Catalyst and Ammonia ($/MWh)	1.00	0.15	-	1.00
CO Oxidation Catalyst ($/MWh)	0.40	0.05	-	0.30
Other Chemicals and Consumables	0.18	0.18	0.18	0.18
Water ($/MWh)	0.08	0.09	0.07	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, 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-12. The tariffs for NYC and Long Island are unchanged from the 2010 Demand Curve Reset Study.

Table II-12 — Fuel Transportation Charges (2013 $)

	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-13.

Table II-13 — Income Tax Assumptions

	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 II-14. 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-14 — Financing Assumptions

	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)	12.50%	12.50%	12.50%	12.50%
Cost of Debt (nominal)	7.00%	7.00%	7.00%	7.00%
Cost of Equity (real)	9.97%	9.97%	9.97%	9.97%
Cost of Debt (real)	4.59%	4.59%	4.59%	4.59%
Weighted Average Cost of Capital *				
Before-Tax (nominal)	9.75%	9.75%	9.75%	9.75%
After-Tax (nominal)	8.16%	8.36%	8.36%	8.36%
Before-Tax (real)	7.28%	7.28%	7.28%	7.28%
After-Tax (real)	6.24%	6.37%	6.37%	6.37%
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%

* (Equity Fraction x Cost of Equity) + (Debt Fraction x Cost of Debt), before tax; and (Equity Fraction x Cost of Equity) + [(Debt Fraction x Cost of Debt) x (1 – 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)] x [Target Cash Flow to Equity + Principal – 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 ound.**II-15.

Table II-15 — 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-16. 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-16 — 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	16.93	17.57	17.57
15-year amortization	13.20	13.72	13.72
20-year amortization	11.31	11.74	12.43
25-year amortization	10.24	10.62	11.71
30-year amortization	9.59	9.93	11.26
35-year amortization	9.15	9.47	10.96

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	17.18	17.89	17.89
15-year amortization	13.56	14.18	14.18
20-year amortization	11.72	12.25	12.94
25-year amortization	10.61	11.08	12.17
30-year amortization	9.93	10.36	11.69
35-year amortization	9.48	9.88	11.37

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.

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.[47]

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. 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 conduct production costs simulations of the NYISO dispatch for the May 2014 to April 2017

[47]Services Tariff §5.14.1.2.

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.[48] 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
Dunkirk 3 & 4	Out	In	In	Out

[48] 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 3% increments through change to load levels.

Resource	CARIS 2 As Found	Statistical Analysis	CARIS 2 Matching Statistical Analysis	CARIS 2 Target Case
Astoria 2	Out	In	In	Out
Astoria 4	Out	Out	Out	Out
Far Rockaway 4	Out	In	In	Out
Glenwood 4	Out	In	In	Out
Glenwood 5	Out	In	In	Out
Nine Mile 2 Uprate	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 the 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 operational for the entire analysis as they were modelled as operating through the use of dummy variables. The opposite applies to Astoria 4, and its deactivation in July 2011 is subsumed within the dummy variable for AE2. 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 Market versus opportunistic behavior in the 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. These cost-based offers for energy-limited units may include adders to ensure that the plants are not run at less profitable times when otherwise a unit might exceed its energy constraint. Thus, the frame units in Zones C and F have had their utilization restricted to approximately 950 hours. Furthermore, we assume that if the plant is scheduled to operate in the day-ahead market, if it is economic and if 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 and 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 the NYISO for the 2011 Congestion Assessment and Resource Integration Study (CARIS). CARIS is the economic planning process used by the 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 the 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.[49] As the CARIS 2 data base had recently been reviewed and validated by the NYISO and stakeholders, they were taken as found and we did not repeat the review and validation process. GE used the MAPS version on which the CARIS2 data base was prepared.

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 the 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

[49] 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 from that excess level by 3% and 6% increments or decrements through change to load levels.

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 the causal variables. We also further adjust our predictions to account 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 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 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 and the Rockland County portion of Zone G[50], 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. 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 as 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,

[50] While Tetco M3 is not physically deliverable to Rockland County, it is used as a proxy for Millennium.

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

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 prices[51]. 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.

[51] 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.

Almost all causal factors except temperature work as expected. Thus, for example, price increases as load increases, and increases faster the more load increases.[52]Prices are generally higher on the weekends and in the shoulder months (adjusting for load differences) to reflect 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.”[53]

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

[52] This result follows from the strongly positive effects on the cube of load.

[53]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.

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 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[54]) and the Bayonne Energy Center (BEC), which have been fully

[54] The AE2 adjustment also captures the deactivation of Astoria 4.

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 percent 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, 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 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.

Finally, while we have called these variables an AE2 effect and a Bayonne effect, their status as simple time-based indicator variables may well be considered ”shorthand” for other effects in the data such that these variables reflect the significant *net* effect of many variables. For example, operating protocols at NYISO have changed over this period to allow more efficient interchanges with PJM and ISO-NE. Thus, it would be a mistake to regard the *estimated* effect as equal to the *actual* effect of these two units alone.

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.

3. Zonal to Nodal Adjustments

The statistical model uses zonal-level prices as the dependent variable. Since generators are paid nodal prices at 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.

In selecting the nodes, we considered coordination with the deliverability study being conducted by the 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 two percent 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 one percent below the Zone while Roseton is nearer to two percent. We used the Bowline basis for the nodal adjustment for Rockland County and Roseton for Dutchess County. In Zone F, the 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.

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 the 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 reduce 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. Gas Constraints

The proxy peaking plants are all primarily natural gas fired. On cold winter days, natural gas can be constrained as a result of high heating demand. In LI, NYC and Zone G to J, we have assumed dual fuel capability (in addition to gas, the plants can burn ULSD). As a result, the net energy revenues earned by these plants should not be materially affected by gas constraints. However, in Zones C and F we have not assumed dual fuel. In exploring this issue with NYISO we have concluded that circumstances of gas unavailability in Zone C would be rare. In Zone F, gas constraints can be more frequent. It is not necessarily the case that gas would be unavailable, but rather that usage restrictions could apply or obtaining gas intraday could be difficult on very cold days. To reflect this, we have eliminated any net energy revenue for the frame units in Zone F from operation on days when the maximum temperature is less than 20 degrees Fahrenheit[55]. This threshold is based on discussions with NYISO and represents NYISO staff's judgment as to conditions that lead to pipelines experiencing delivery concerns.

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[55] We began by restricting real-time operation on these days and examined as a sensitivity restricting all operation. As restricting all operations only reduced net energy revenues by less than an additional $0.10 per kW year over restricting just real time operation on these days, we used that as the base assumption.

8. Miscellaneous Factors

There are a 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 the 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 revenues[56] 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 would possibly understate net energy revenues. On

[56] 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.

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.

9. Ancillary Service Revenues

Finally, for the LMS 100 and Frame units, we have included adjustments for Ancillary Services revenues for operating reserves and voltage support service (VSS). The NYISO supplied us with average 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 about $3.56 per kW in non-spinning reserve revenue, the LMS 100 unit in NYC earn just under $6 per kW in non-spinning reserve revenues and the values for Zones G to J are approximately $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.

Additionally, we note that 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.

S&L advised NERA that the simple cycle frame units could not reach full output in ten minutes. NYISO rules do not permit units which are block loaded to qualify for ten minute non-spinning reserve revenues if they can't reach full output in ten minutes. These units could however qualify for 30 minute non-spinning revenues. NYISO analysed revenues for units in the 30 minute non-spinning market and the weighted average revenue was $0.21 per kW year. Given the relatively low level of this value it was used without adjustment for operating hours. Additionally, these units were credited with VSS revenues of $2.02 per kW year based on a review of the average VSS revenues earned by units that participated in the 30 minute reserve market.

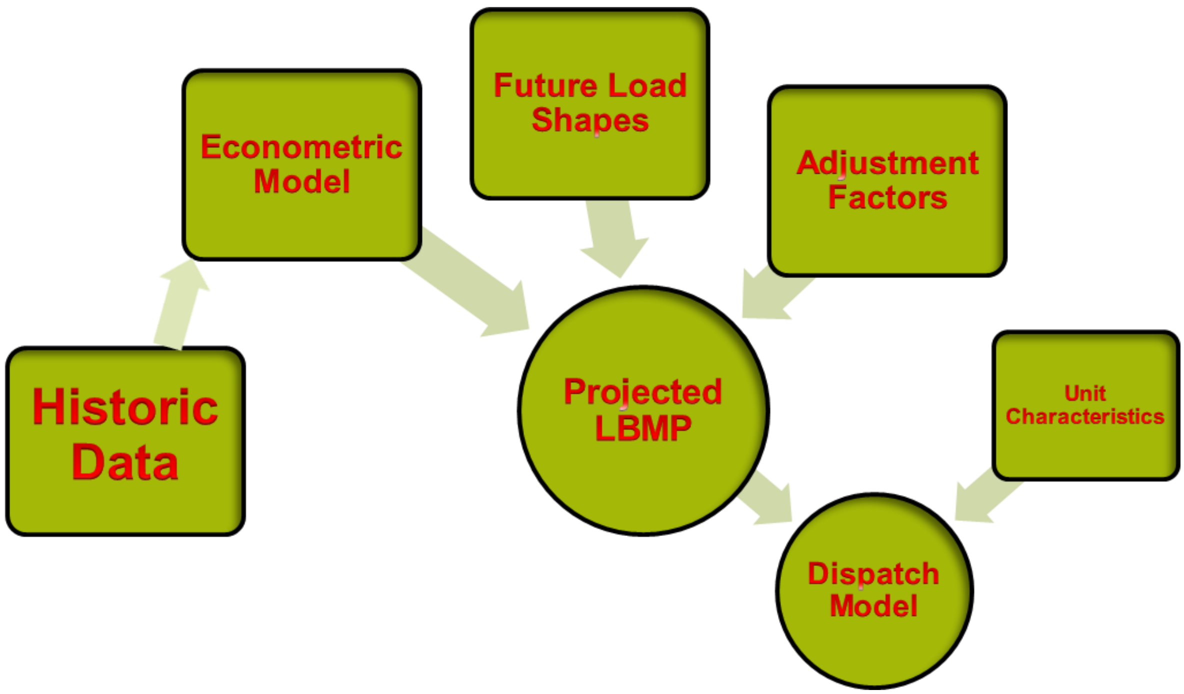
Based on data provided by NYISO, we assumed that a combined cycle unit could earn $ 7.50 per kW year, albeit in large part from spinning reserve and regulation revenue as opposed to non-spinning reserve revenue. For the sensitivity case where the CC in NYC runs less, but gets tax abatement, the Ancillary Service value was reduced to $ 3.75 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 AS factors for the LMS 100 units has been posted to the NYISO website.

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, aggregate net revenues, run hours and number of starts. 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. The energy model used to develop the Demand Curve 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 net energy revenues using four 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 econometric model adjusted for resource mix changes only

d) The final set of LBMPs after all adjustments including up to minimum capacity plus 190 MW level.

This will yield four different set of projected net energy revenues in each of five relevant zones (NYC, LI, HV, Central, Capital) for each of three technologies (LMS100 or Frame GT 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 $/KW/YEAR

	LMS100			Frame		CCGT				
	HVL	**LI**	**NYC**	**ZONEC**	**ZONEF**	**HVL**	**LI**	**NYC**	**ZONEC**	**ZONEF**
	Based on Actual LBMPs									
2010	38.29	74.50	49.27	8.90	16.14	80.71	125.13	97.65	36.80	66.96
2011	35.82	74.41	43.30	12.93	16.56	82.21	134.78	100.91	39.09	58.52
2012	26.87	94.77	33.38	8.04	7.19	66.47	146.97	88.83	55.10	40.61
Average	*33.66*	*81.23*	*41.98*	*9.96*	*13.30*	*76.46*	*135.63*	*95.80*	*43.66*	*55.36*
	Based on Regression Prior to Any MAPS Adjustments									
2014-2015	32.19	94.66	39.83	10.24	13.01	61.01	164.07	80.96	39.44	47.44
2015-2016	33.34	96.75	40.89	10.62	13.47	62.17	167.36	82.43	39.60	48.22
2016-2017	34.25	99.99	41.82	10.84	14.05	65.26	173.14	86.13	41.31	50.36
Average	*33.26*	*97.13*	*40.85*	*10.57*	*13.51*	*62.81*	*168.19*	*83.18*	*40.12*	*48.67*
	Based on Regression Adjusted by MAPS Factor for Resource Mix									
2014-2015	33.30	96.16	40.62	10.47	13.28	62.26	165.82	82.06	40.51	48.18
2015-2016	34.38	98.30	41.52	10.89	13.67	63.67	169.15	83.55	40.60	48.93
2016-2017	35.27	101.61	42.77	11.16	14.26	66.70	174.96	87.25	42.35	51.23
Average	*34.32*	*98.69*	*41.64*	*10.84*	*13.74*	*64.21*	*169.98*	*84.29*	*41.15*	*49.45*
	Based on Regression Adjusted by MAPS Factor for Resource Mix and 190MW Excess									
2014-2015	35.09	99.51	42.84	12.40	14.90	67.56	171.71	87.59	48.08	54.81
2015-2016	36.25	102.02	44.00	12.78	15.30	68.71	175.13	88.98	48.22	55.51
2016-2017	37.56	105.63	45.49	13.01	15.71	72.03	180.92	92.84	50.32	58.18
Average	*36.30*	*102.39*	*44.11*	*12.73*	*15.30*	*69.43*	*175.92*	*89.80*	*48.87*	*56.17*
	Approximate Estimates by MMU									
2010	41.71	86.28	45.82	N/A	7.45	87.66	151.55	87.20	N/A	73.22
2011	35.77	95.64	40.77	N/A	8.96	88.75	168.03	88.98	N/A	63.82
2012	38.12	112.55	35.26	N/A	13.52	95.74	174.37	89.28	N/A	84.17
Average	*38.53*	*98.16*	*40.61*	*N/A*	*9.98*	*90.72*	*164.65*	*88.49*	*N/A*	*73.73*

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 user specified capital recovery period, using the financial assumptions of a 50%/50% capital structure and 7.00%/12.50% 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 level[57] 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 (a peaking unit 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 peaking unit is an LMS100 in all locations except ROS where it is a Siemens Frame type unit.

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

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

note that in selecting inputs, we are guided also by the result produced. The results produced using the recommended shape and slope of the Demand Curves show implied amortization periods of 17.5 years in the Capital and Central zones, 18.5 years in Zones G to J, 14.5 years in NYC and 17.5 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. 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 17.5 years in ROS and Long Island and 18.5 years in Zones G to J are similar. NYC has the lowest implied amortization period at 14.5 years.

B. Financial Parameters

The development of financial parameters, the capital structure and costs of capital is an issue over which stakeholders hold multiple perspectives. NERA's review with stakeholders began at the March 11, 2013 Working Group meeting, where NERA proposed using a weighted average cost of capital (WACC) of 9.25% for merchant generators to establish the Demand Curve. This WACC had been 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. Following observed shifts in capital market conditions during July 2013, NERA updated its recommendation to reflect how those changing conditions would influence financings for new power plants. NERA developed an updated recommendation of 9.75% for a merchant generator, reflecting again a capital structure of 50% debt and 50% equity, a 7.0% cost of debt and a 12.5% cost of equity

NERA's cost of capital estimate is premised on the assumption that the merchant generator is able to raise capital at the corporate level, and benefits from a diversified fuel mix and exposure to different geographic markets. NERA does not believe the alternative assumption – i.e., that the facility is financed without the benefits of fuel and geographic diversity – is appropriate as it would overstate the cost at which firms can raise capital for such projects.

The updated cost of debt is based upon a range of observed yields for companies in the industry that range from 3.41%[i] to 6.83%, and recognizing that BB and BBB corporate bonds are yielding approximately 5.56% and 4.14% respectively as of July 5, 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 generic BB and BBB bond indices where the average duration of the underlying bonds is 7 to 10 years. Bond financing of a longer duration would tend to carry a higher yield. NERA also examined specific debt issues outstanding for generation companies. In July 2013, these ranged from 5.37 % to 6.83% for long-term financings with maturities greater than 15 years.[58]

The recommended cost of equity is derived using the capital asset pricing model (CAPM). The CAPM relies upon a risk-free rate of 3.68% (30-year US treasury yield as of July 5, 2013)[59] and an equity beta of 1.15. A market risk premium of 6.62% was used in the CAPM calculation.[60] The recommended 12.5% return on equity is above the calculated cost of equity of 11.29 %. The rationale for this is based on examination of the results of the CAPM model for regulated electricity business whose current allowed ROEs tend to fall in the 9% to 11% range. The CAPM model produces a return of 7.72% for entities without material unregulated activates and of 8.56% for entities that are a hybrid of regulated and unregulated businesses. This indicates that capacity results based upon long-term inputs currently understate the cost of equity and supports an equity cost of 12.5% for merchant generators. With merchant power plants posing greater investment risks to investors, the sector has always carried a risk premium relative to regulated utilities.

NERA ran the CAPM model for specific firms operating in the sector, using the Value-Line betas, as shown in the table below.

[58] NERA did identify one issuer, Ameren Generating Company, whose bond yields have risen to over 10%, although this appears to be a special, issuer-specific situation that does not reflect a trend in the broader industry.

[59] Federal Reserve Statistical Release. Selected Interest Rates. http://www.federalreserve.gov/releases/h15/update/.

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

Cost of Equity Based on Most Recent 5-Year Beta Available from Value Line

Company	Value Line Reported 5-Year Beta	Report Date	Debt to Capital Ratio	Cost of Equity
(1)	(2)	(3)	(4)	(5)
Generators				
AES	1.20	3/29/2013	66.6%	11.62%
Calpine	1.15	6/7/2013	52.8%	11.29%
NRG Energy	1.10	3/29/2013	65.2%	10.96%
Group Average	1.15			11.29%
Integrated Utilities with Generator Components				
Ameren	0.80	3/22/2013	45.3%	8.98%
Dominion Resources	0.65	5/24/2013	32.5%	7.98%
Entergy	0.70	3/22/2013	51.7%	8.31%
Exelon	0.80	5/24/2013	37.9%	8.98%
PPL	0.65	5/24/2013	49.6%	7.98%
Public Service Enterprise Group	0.75	5/24/2013	27.1%	8.65%
TransAlta	0.70	3/29/2013	52.5%	8.31%
TransCanada	0.85	6/7/2013	34.2%	9.31%
Group Average	0.74			8.56%
Integrated Utilities/Distribution Utilities				
Con Ed	0.60	5/24/2013	35.9%	7.65%
CH Energy Group	0.60	5/24/2013	33.6%	7.65%
Northeast Utilities System	0.70	5/24/2013	34.2%	8.31%
The Southern Company	0.55	5/24/2013	32.5%	7.32%
Xcel Energy	0.60	5/3/2013	40.3%	7.65%
Group Average	0.61			7.72%

Notes and Sources:

5-Year betas are from Value Line. Data used to derive debt to capital were obtained from Value Line.
As Value Line no longer issues full reports for Calpine, its debt-to-capital ratio was derived from data obtained from Bloomberg Finance L.P.
Cost of equity is calculated using CAPM with a 3.68% risk free rate and 6.62% market risk premium.

As discussed above, from this analysis, it is clear that the CAPM is understating the cost of equity in the current interest rate environment. If regulated utilities equity costs were in the low 9% range and CAPM shows an ROE in the high 7% range, the CAPM understatement would be over 100 basis points. NERA therefore relies upon an ROE that is above the value calculated by CAPM. In our opinion, it is reasonable to apply an ROE for the generic demand curve reset that is above the CAPM estimate in the current capital market environment.

At the working group meeting, a representatives of the transmission owners and large customers 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 12.5 percent is reasonable as it provides an appropriate premium relative to the price-regulated firms against whom merchant generators 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.

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	**10.81 (without incentives)** **12.32 (with incentives)**	
Demand Curve Merchant Assumption	**12.50**	**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 years, 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 year, NERA received similar feedback, 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 in turn.

Corporate versus project financing – We believe that a merchant generator project would likely 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, this type of merchant project would not be financed most economically as a stand-alone project. NERA reviewed the financing costs for stand-alone merchant projects, as reported in Project Finance magazine, and observed very high financing cost (premiums of 700 to 900 basis points above LIBOR), low $/kW loan levels and tenors of less than ten years. As a result, we believe the best starting 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 include a plausible project financing scenario as a sensitivity.

Risks Specific to New York and Undiversified Generators – As stated at the outset of this section, we believe it is inappropriate 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 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.

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 and technological improvement trends. On balance, we believe this approach provides a fair solution for the establishment of the Demand Curve reset parameters.

The specific components of the WACC calculation are detailed below:

Debt/Capital	50%
Debt Cost	7.00%
Equity Beta	1.15%
Equity Risk Premium	6.62%
Risk-Free Rate (30 yr)	3.68%
Calculated Cost of Equity	11.29%
Recommended Equity Cost	12.50%
WACC	9.75%

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. The table above, showing CAPM results, also shows the capital structure of a range of entities operating in the sector. In addition, we show below the yields on outstanding bonds for existing companies in the generation sector.

Sample Debt Costs for Power Generators

Company	Ticker	Mty Type	Crncy	Bid Yld to Mty	Amount Issued	Collateral Type	Issue Date	Years to Mty
AES CORPORATION	AES	CALLABLE	USD	5.87	750,000,000	SR UNSECURED	4/30/2013	9.85
AES CORPORATION	AES	CALLABLE	USD	5.72	1,000,000,000	SR UNSECURED	6/15/2011	7.98
AES CORPORATION	AES	CALLABLE	USD	5.72	1,000,000,000	SR UNSECURED	6/15/2011	7.98
AES CORPORATION	AES	CALLABLE	USD	5.87	999,500,000	SR UNSECURED	8/1/2012	7.98
AES CORPORATION	AES	CALLABLE	USD	5.37	625,000,000	SR UNSECURED	5/20/2009	6.90
ALLEGHENY ENERGY SUPPLY	FE	CALLABLE	USD	6.50	250,000,000	SR UNSECURED	10/1/2009	26.27
ALLEGHENY ENERGY SUPPLY	FE	CALLABLE	USD	6.50	250,000,000	SR UNSECURED	10/1/2009	26.27
ALLEGHENY ENERGY SUPPLY	FE	CALLABLE	USD	3.94	350,000,000	SR UNSECURED	10/1/2009	6.27
ALLEGHENY ENERGY SUPPLY	FE	CALLABLE	USD	3.94	350,000,000	SR UNSECURED	10/1/2009	6.27
CALPINE CORP	CPN	CALLABLE	USD	6.83	1,200,000,000	SR SECURED	1/14/2011	9.52
CALPINE CORP	CPN	CALLABLE	USD	6.52	1,200,000,000	SR SECURED	1/14/2011	9.52
CALPINE CORP	CPN	CALLABLE	USD	6.47	2,000,000,000	SR SECURED	10/22/2010	7.61
CALPINE CORP	CPN	CALLABLE	USD	6.40	2,000,000,000	SR SECURED	10/22/2010	7.61
CALPINE CORP	CPN	CALLABLE	USD	6.59	1,100,000,000	SR SECURED	7/23/2010	7.06
CALPINE CORP	CPN	CALLABLE	USD	6.59	1,100,000,000	SR SECURED	7/23/2010	7.06
CALPINE CORP	CPN	CALLABLE	USD	6.80	400,000,000	SR SECURED	5/25/2010	6.10
CALPINE CORP	CPN	CALLABLE	USD	6.80	400,000,000	SR SECURED	5/25/2010	6.10
EXELON GENERATION CO LLC	EXC	CALLABLE	USD	5.59	788,203,000	SR UNSECURED	2/12/2013	28.94
EXELON GENERATION CO LLC	EXC	CALLABLE	USD	5.57	350,000,000	SR UNSECURED	9/30/2010	28.23
EXELON GENERATION CO LLC	EXC	CALLABLE	USD	5.76	900,000,000	SR UNSECURED	9/23/2009	26.23
EXELON GENERATION CO LLC	EXC	CALLABLE	USD	4.20	523,303,000	SR UNSECURED	2/12/2013	8.94
EXELON GENERATION CO LLC	EXC	CALLABLE	USD	3.91	550,000,000	SR UNSECURED	9/30/2010	7.23
EXELON GENERATION CO LLC	EXC	CALLABLE	USD	3.55	600,000,000	SR UNSECURED	9/23/2009	6.23
PPL ENERGY SUPPLY LLC	PPL	CALLABLE	USD	5.82	300,000,000	SR UNSECURED	12/14/2006	23.44
PPL ENERGY SUPPLY LLC	PPL	CALLABLE	USD	4.47	712,415,000	SR UNSECURED	12/16/2011	8.44
PSEG POWER LLC	PEG	CALLABLE	USD	5.50	500,000,000	COMPANY GUARNT	4/16/2001	17.77
PSEG POWER LLC	PEG	CALLABLE	USD	5.50	500,000,000	COMPANY GUARNT	4/16/2001	17.77
PSEG POWER LLC	PEG	CALLABLE	USD	5.37	499,720,700	COMPANY GUARNT	12/10/2001	17.77
PSEG POWER LLC	PEG	CALLABLE	USD	3.72	250,000,000	COMPANY GUARNT	9/19/2011	8.19
PSEG POWER LLC	PEG	CALLABLE	USD	3.41	406,004,000	COMPANY GUARNT	8/11/2010	6.77
PSEG POWER LLC	PEG	CALLABLE	USD	3.55	406,004,000	COMPANY GUARNT	4/5/2010	6.77
TRANSALTA CORP	TACN	CALLABLE	USD	6.72	300,000,000	SR UNSECURED	3/12/2010	26.69
TRANSALTA CORP	TACN	AT MATURITY	CAD	6.81	141,100,000	SR UNSECURED	11/15/2005	17.36
TRANSALTA CORP	TACN	CALLABLE	CAD	6.83	110,000,000	SR UNSECURED	10/22/1999	16.29
TRANSALTA CORP	TACN	CALLABLE	USD	4.97	400,000,000	SR UNSECURED	11/7/2012	9.36
TRANSALTA CORP	TACN	AT MATURITY	CAD	4.53	400,000,000	SR UNSECURED	11/18/2009	6.36

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.[61] 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. We recommend that 2.3% be used as the long term

[61]http://www.phil.frb.org/research-and-data/real-time-center/survey-of-professional-forecasters/2013/survq113.cfm

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 and the model 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 the user specified economic life. 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 revenues per unit of ICAP capacity and use the NYISO formula to adjust the Annual Reference Value per unit of ICAP capacity 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 values for WSRs in the relevant locations that are consistent with 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 the NYISO website. The factors for each zone are as follows:

	NYC	G-J	LI	NYCA/ROS
LMS/Frame	1.0872	1.0682	1.0699	1.0464
CC	1.0868	1.0680	1.0692	1.0463

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 7.00% and a 50% equity share at 12.50%.

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 consistent with this amortization period.[62]

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

[62] 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.

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. We begin with an economic life that represents the period over which an investor would analyze cost recovery. For the LMS100 and CCGT units we use 25 years; for the simple cycle frame units we use 20 years. The interaction between the Demand Curve shape and slope and amortization period is then examined on a present value basis over the respective economic lives.

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 retain the shape of the current Demand Curves and move the zero crossing points toward levels consistent with the reliability analysis conducted by NYISO and FTI. We recommend using 113.5% for NYCA, 115% for the G-J Zone, 116.5% for NYC and 118% for LI.

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. 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.[63] 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.

[63] http://www.eia.gov/forecasts/aeo/assumptions/pdf/0554%282012%29.pdf – pages 94-95

Residual value is the value of the unit at the end of the economic 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. For the Frame units, which are less efficient, we use zero residual value.

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 Risk – A regulatory risk adjustment has not been included in the Demand Curve model nor in the estimated cost of equity. The Demand Curve construct has been operating for ten years. Efforts are constantly underway to improve the process and to refine elements that would bias the process. For example, the NYISO is moving to raise the default mitigation level from 75% of Net Cone to 100% of Net Cone in the buyer side mitigation rules and to introduce exemptions from mitigation for merchant entry and repowering. NERA does recognize that the capacity payment mechanism affected through the Demand Curve is not as purely supply and demand driven as is the energy market. The Demand Curve is an administratively determined price. There are reasonable arguments that a market which is administrative is subject to risks that can be categorized as regulatory risks. For purposes of this reset we have concluded that it would be reasonable to develop the Demand Curve without a regulatory risk adjustment in light of the NYISO's efforts to improve mitigation measures in the capacity market. We do, however, recommend that the NYISO monitor and examine this issue anew in future resets.

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 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 capacity excess which reflects the capacity of the proxy plant under ICAP conditions in that location.

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 the 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. This would cover any unit coming into service by April 2017, the last month of the reset period. 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. Hence, this cost would somewhat overstate net energy revenues for an NYC CCGT operating to achieve fuel abatement, but should be reasonably close. We also reduce AS revenues. Even under this sensitivity, the LMS 100 has a lower net cost in NYC.

Deliverability –NYISO’s Deliverability Study did not identify any system deliverability upgrade costs.

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.

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.

Revenue and cost stability is also a concern when selecting the zero crossing point. If the zero crossing point is too close to the target, it would be very difficult for a new efficient entrant to enter without depressing capacity market prices and rendering its entry uneconomic. For example, in New York City, the recommended zero crossing point is at 116.5% or roughly 1650 MW above the target. This allows a new entrant between 300 MW and 400 MW to enter and only push down capacity prices by 20% to 25%. A new entrant of between 500 MW and 600 MW could enter and would push capacity prices down by roughly a third. While these are significant impacts, they do not appear to preclude entry by efficient large scale new plants. However, moving the zero crossing point closer to the target would potentially run the risk that entry by a large scale new plant would be deterred by the early year impact on capacity prices. For example, at 110% zero crossing point, a new 500 MW plant in New York City would result in a roughly 50% drop in capacity prices. Impacts in the New Capacity Zone would be roughly half that in NYC and in NYCA the impact would be roughly one-fourth that in NYC. However, plants as large as 1000 MW are proposed in the Lower Hudson Valley and would be feasible in Zones A to F. It is important that the Demand Curve not deter potential entry by efficient new plants. In the long term that would raise the cost to customers for both energy and capacity. In formulating the shape and slope recommendations we are mindful that the zero crossing point should not, given the capacity requirement in the location, which result in a curve so steep that it would deter entry by a large efficient new plant.

While the curves we recommend do not in our view reach the absolute limit in that regard, if they were to be changed to be significantly steeper, they would exceed that limit. As we adjust the reference value down as we extend the curve and a less steep curve does not have any negative cost consequences to customers, we see no reason to risk the potential entry deterring impact of steeper curves than we have recommended.

The slopes in the current Demand Curves are reasonable as they result in implied amortization periods of 17.5 years in in NYCA and LI, 18.5 years in Zones G to J and 14.5 years in NYC, respectively, resulting in a sustainable market system. 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. 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.

In summary, we find that zero crossing points that move in the direction indicated by the FTI Study relating the marginal valve of reliability to the zero crossing point meet appropriate criteria with respect to the other factors we consider.

V. Sensitivity Analyses

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	SC	112.0%	91.31
C - Central	SC	113.5%	90.62
C - Central	SC	115.0%	90.10
C - Central	CC	112.0%	135.81
C - Central	CC	113.5%	134.35
C - Central	CC	115.0%	133.26
F - Capital	SC	112.0%	89.49
F - Capital	SC	113.5%	88.81
F - Capital	SC	115.0%	88.31
F - Capital	CC	112.0%	139.90
F - Capital	CC	113.5%	138.40
F – Capital	CC	115.0%	137.27
G – J – LHV Dutchess	LMS100	112.0%	181.57
G – J – LHV Dutchess	LMS100	113.5%	176.56
G – J – LHV Dutchess	LMS100	115.0%	173.03
G – J – LHV Dutchess	CC	112.0%	189.12
G – J – LHV Dutchess	CC	113.5%	179.87
G – J – LHV Dutchess	CC	115.0%	173.58
G – J – LHV Rockland	LMS100	112.0%	180.26
G – J – LHV Rockland	LMS100	113.5%	175.26
G – J – LHV Rockland	LMS100	115.0%	171.75
G – J – LHV Rockland	CC	112.0%	170.42
G – J – LHV Rockland	CC	113.5%	162.06

Region	Unit	Zero Crossing Point	Reference Price 2014$/KW-Year
G – J – LHV Rockland	CC	115.0%	156.39
J - New York City	LMS100	115.0%	251.74
J - New York City	LMS100	116.5%	245.04
J - New York City	LMS100	118.0%	240.08
J - New York City	CC	115.0%	400.61
J - New York City	CC	116.5%	381.62
J - New York City	CC	118.0%	367.88

B. Gas Prices

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

Region	Unit	Zero Crossing Point	Historical Gas Reference Price 2014$/KW-Year	Futures Gas Reference Price 2014$/KW-Year
C – Central	SC	113.5%	90.62	90.71
C – Central	CC	113.5%	134.35	142.24
F – Capital	SC	113.5%	88.81	91.10
F – Capital	CC	113.5%	138.40	150.83
G – J – Dutchess	LMS100	115.0%	173.03	174.41
G – J - Dutchess	CC	115.0%	173.58	182.94
G – J – Rockland	LMS100	115.0%	171.75	149.79
G – J - Rockland	CC	115.0%	156.39	116.48
J - New York City	LMS 100	116.5%	245.04	244.01
J - New York City	CC	116.5%	381.62	386.21
K - Long Island	LMS100	118.0%	132.98	124.45
K - Long Island	CC	118.0%	96.49	85.23

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 22 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.

Region	Unit	Zero Crossing Point	Reference Price 2014$/KW-Year
J - New York City	CC	116.5%	381.62
J - New York City with tax abatement	CC	116.5%	296.85

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.

Region	Unit	Zero Crossing Point	Reference Price 2014$/KW-Year
J - New York City	LMS 100	116.5%	245.04
J - New York City Astoria 138 Bus	LMS 100	116.5%	241.45
J - New York City	CC	116.5%	381.62
J - New York City Astoria 138 Bus	CC	116.5%	368.40

E. 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.

Region	Unit	Zero Crossing Point	Standard Plant Size – 0% Reduction in Investment Cost Reference Price 2014$/KW-Year	Double Plant Size – 5% Reduction in Investment Cost 2014$/KW-Year	Double Plant Size – 10% Reduction in Investment Cost 2014$/KW-Year
C – Central	SC	113.5%	90.62	90.14	84.96

Region	Unit	Zero Crossing Point	Standard Plant Size – 0% Reduction in Investment Cost Reference Price 2014$/KW-Year	Double Plant Size – 5% Reduction in Investment Cost 2014$/KW-Year	Double Plant Size – 10% Reduction in Investment Cost 2014$/KW-Year
C – Central	CC	113.5%	134.35	135.58	126.08
F – Capital	SC	113.5%	88.81	88.19	82.97
F – Capital	CC	113.5%	138.40	139.47	129.38
G – J - Rockland	LMS100	115.0%	171.75	186.79	174.27
G – J - Rockland	CC	115.0%	156.39	191.56	175.39
G – J – Dutchess	LMS100	115.0%	173.03	188.30	176.09
G – J - Dutchess	CC	115.0%	173.58	214.23	198.67
J - New York City	LMS 100	116.5%	245.04	285.52	268.20
J - New York City	CC	116.5%	381.62	520.55	487.50
K - Long Island	LMS100	118.0%	132.98	172.46	154.11
K - Long Island	CC	118.0%	96.49	164.30	132.57

F. Merchant Financing

As explained above, generators have raised the issue that merchant project financing (MPF) would be a more appropriate financing assumption. We have developed a case with 1/3 debt at a cost of 9% and 2/3 equity at a cost of 15%. While the parameters of MPF are speculative, we believe that these are reasonable. This sensitivity was developed for the NYC LMS100 and the results are shown below.

Region	Unit	Zero Crossing Point	Reference Price 2014$/KW-Year
J - New York City Base Case	LMS 100	116.5%	245.04
J - New York City MPF Case	LMS 100	116.5%	337.09
J - New York City Base Case	CC	116.5%	381.62
J - New York City MPF Case	CC	116.5%	509.23

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 Zone[64]. Elevation, temperature and relative humidity assumptions are shown by Zone for ISO and ICAP conditions, average winter and summer conditions, and the conditions at the time of the summer and winter peak loads. The latter is provided to support the temperature corrections for Demonstrated Maximum Net Capability in the demand curve model.

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.

[64] 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-7 shows conventional startup times for each technology for cold, warm and hot starts. Fast startup times are shown for the combined cycle technology.

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

Load Zone	Weather Basis	Elevation (ft)	Season	Ambient Temperature (ºF)	Relative Humidity
C - Central	Syracuse	421	Summer	79.7	67.7
			Winter	17.3	73.7
			Spring-Fall	59.0	60.0
			Summer DMNC	91.2	42.4
			Winter DMNC	14.2	65.0
			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
			Summer DMNC	92.4	42.5
			Winter DMNC	11.9	84.5
			ICAP	90.0	70.0
G - Hudson Valley	Newburgh (Rockland Co.)	165	Summer	82.3	77.7
			Winter	19.3	74.0
			Spring-Fall	59.0	60.0
			Summer DMNC	95.4	40.3
			Winter DMNC	19.3	48.5
			ICAP	90.0	70.0
G - Hudson Valley	Poughkeepsie (Dutchess Co.)	165	Summer	82.3	77.7
			Winter	19.3	74.0
			Spring-Fall	59.0	60.0
			Summer DMNC	94.4	41.0
			Winter DMNC	18.0	57.6
			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
			Summer DMNC	94.6	40.6
			Winter DMNC	37.7	77.1
			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
			Summer DMNC	93.9	37.0
			Winter DMNC	22.1	80.0
			ICAP	90.0	70.0

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

	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
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)	99.53	98.26	98.38	98.38	99.83	99.94	Avg. degraded value.
Net Plant Capacity - Summer DMNC (MW)	94.87	93.17	93.44	92.97	93.98	97.99	Avg. degraded value; with evaporative
Net Plant Capacity - Winter DMNC (MW)	99.96	99.55	100.22	100.23	100.40	100.80	Avg. degraded value; evaporative cooler
Net Plant Capacity - ICAP (MW)	92.76	92.00	92.20	92.20	91.80	93.13	Avg. degraded value; with evaporative
Net Plant Capacity - ICAP (MW)	94.17	93.40	93.61	93.61	93.20	94.54	New and clean value; with evaporative
Net Plant Heat Rate - Summer (Btu/kWh)	9,227	9,313	9,271	9,271	9,223	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. (Btu/kWh)	9,157	9,236	9,170	9,170	9,140	9,135	Avg. degraded value.
Net Plant Heat Rate - Summer DMNC (Btu/kWh)	9,264	9,362	9,287	9,295	9,271	9,247	Avg. degraded value; with evaporative
Net Plant Heat Rate - Winter DMNC (Btu/kWhW)	9,081	9,163	9,069	9,071	9,053	9,045	Avg. degraded value; evaporative cooler
Net Plant Heat Rate - ICAP (Btu/kWh)	9,348	9,424	9,351	9,351	9,352	9,335	Avg. degraded value; with evaporative
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
Equivalent Forced Outage Rate - Demand Based	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
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	
Fuel Oil Testing	437,000	436,000	433,000	433,000	0	0	
Administrative and General	394,000	399,000	370,000	373,000	335,000	326,000	
Subtotal Fixed O&M	2,627,000	2,866,000	2,377,000	2,408,000	1,525,000	1,442,000	
$/kW-year	**14.16**	**15.58**	**12.89**	**13.06**	**8.31**	**7.74**	Based on net degraded ICAP capacity.
Other Fixed Costs ($/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	2,765,000	4,306,000	2,491,000	2,522,000	1,639,000	1,556,000	
$/kW-year	**14.90**	**23.40**	**13.51**	**13.68**	**8.93**	**8.35**	Based on net degraded ICAP capacity.
Property Taxes (without tax abatement)	2,367,000	15,826,000	2,144,000	2,198,000	1,972,000	1,861,000	Full amount, not accounting for UTEP
Insurance	1,894,000	2,051,000	1,715,000	1,758,000	1,578,000	1,489,000	
Total Fixed O&M with Insurance and Property Taxes	7,026,000	22,183,000	6,350,000	6,478,000	5,189,000	4,906,000	
$/kW-year	**37.87**	**120.56**	**34.44**	**35.13**	**28.26**	**26.34**	Based on net degraded ICAP capacity.
Variable O&M ($/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
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 ($/MWh)	**5.47**	**5.52**	**5.47**	**5.48**	**5.38**	**5.36**	Based on net degraded summer/winter
Variable O&M - Cost per Start:							Excluding natural gas consumed (shown
Major Maintenance Parts	n/a	n/a	n/a	n/a	n/a	n/a	.
Major Maintenance Labor	n/a	n/a	n/a	n/a	n/a	n/a	Labor rates consistent with capital cost
Total ($/factored start)	n/a	n/a	n/a	n/a	n/a	n/a	Factored starts include representative

* For combined cycle cases, value shown is for entire plant.

Combustion Turbine Model	Zone K (LI) 1 x 1 x 1 SGT6-5000F(5)	Zone J (NYC) 1 x 1 x 1 SGT6-5000F(5)	Zone G (HV) - Dutchess 1 x 1 x 1 SGT6-5000F(5)	Zone G (HV) - Rockland 1 x 1 x 1 SGT6-5000F(5)	Zone F (Alb) 1 x 1 x 1 SGT6-5000F(5)	Zone C (Syr) 1 x 1 x 1 SGT6-5000F(5)	Comments
Plant Performance (per Unit)*							
Net Plant Capacity - Summer (MW)	316.66	313.96	310.92	310.92	314.11	314.45	Avg. degraded value; with evaporative
Net Plant Capacity - Winter (MW)	326.97	325.90	325.86	325.86	325.34	328.31	Avg. degraded value; evaporative cooler
Net Plant Capacity - Summer/Winter Avg. (MW)	321.81	319.93	318.39	318.39	319.72	321.38	Avg. degraded value.
Net Plant Capacity - Summer DMNC (MW)	311.19	308.10	306.95	306.04	308.11	312.04	Avg. degraded value; with evaporative
Net Plant Capacity - Winter DMNC (MW)	325.79	327.42	325.08	325.16	324.24	327.31	Avg. degraded value; evaporative cooler
Net Plant Capacity - ICAP (MW)	304.87	303.89	302.78	302.78	302.03	301.67	Avg. degraded value; with evaporative
Net Plant Capacity - ICAP (MW)	314.30	313.29	312.14	312.14	311.37	311.00	New and clean value; with evaporative
Net Plant Heat Rate - Summer (Btu/kWh)	7,196	7,237	7,217	7,217	7,197	7,168	Avg. degraded value; with evaporative
Net Plant Heat Rate - Winter (Btu/kWh)	7,081	7,104	7,090	7,090	7,097	7,033	Avg. degraded value; evaporative cooler
Net Plant Heat Rate - Summer/Winter Avg. (Btu/kWh)	7,139	7,171	7,154	7,154	7,147	7,101	Avg. degraded value.
Net Plant Heat Rate - Summer DMNC (Btu/kWh)	7,295	7,327	7,314	7,324	7,286	7,177	Avg. degraded value; with evaporative
Net Plant Heat Rate - Winter DMNC (Btu/kWhW)	7,090	7,106	7,098	7,098	7,108	7,044	Avg. degraded value; evaporative cooler
Net Plant Heat Rate - ICAP (Btu/kWh)	7,268	7,291	7,278	7,278	7,272	7,240	Avg. degraded value; with evaporative
Net Plant Heat Rate - ICAP (Btu/kWh)	7,050	7,073	7,060	7,060	7,054	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	791	792	794	794	791	789	
Winter	763	762	778	778	776	769	
Spring-Fall	784	783	784	784	784	778	
Average	780	780	785	785	784	779	
ICAP	801	799	802	802	801	799	

Combustion Turbine Model	Zone K (LI) 1 x 1 x 1 SGT6-5000F(5)	Zone J (NYC) 1 x 1 x 1 SGT6-5000F(5)	Zone G (HV) - Dutchess 1 x 1 x 1 SGT6-5000F(5)	Zone G (HV) - Rockland 1 x 1 x 1 SGT6-5000F(5)	Zone F (Alb) 1 x 1 x 1 SGT6-5000F(5)	Zone C (Syr) 1 x 1 x 1 SGT6-5000F(5)	Comments
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	
Fuel Oil Testing	551,000	551,000	547,000	547,000	0	0	
Administrative and General	660,000	669,000	620,000	625,000	561,000	547,000	
Subtotal Fixed O&M	8,679,000	8,862,000	7,854,000	7,956,000	6,105,000	5,820,000	
$/kW-year	**28.47**	**29.16**	**25.94**	**26.28**	**20.21**	**19.29**	Based on net degraded ICAP capacity.
Other Fixed Costs ($/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	9,139,000	12,462,000	8,234,000	8,336,000	6,485,000	6,200,000	
$/kW-year	**29.98**	**41.01**	**27.19**	**27.53**	**21.47**	**20.55**	Based on net degraded ICAP capacity.
Property Taxes (without tax abatement)	4,145,000	28,616,000	3,543,000	3,680,000	3,200,000	3,010,000	Full amount, not accounting for UTEP
Insurance	3,316,000	3,709,000	2,834,000	2,944,000	2,560,000	2,408,000	
Total Fixed O&M with Insurance and Property Taxes	16,600,000	44,787,000	14,611,000	14,960,000	12,245,000	11,618,000	
$/kW-year	**54.45**	**147.38**	**48.26**	**49.41**	**40.54**	**38.51**	Based on net degraded ICAP capacity.
Variable O&M ($/MWh)							
Major Maintenance Parts	0.25	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

* For combined cycle cases, value shown is for entire plant.

Combustion Turbine Model	Zone F (Alb - Simple Cycle) Simple Cycle SGT6-5000F(5)	Zone C (Syr - Simple Cycle) Simple Cycle SGT6-5000F(5)	Comments
Plant Performance (per Unit)*			
Net Plant Capacity - Summer (MW)	213.70	213.10	Avg. degraded value; with evaporative
Net Plant Capacity - Winter (MW)	226.20	226.20	Avg. degraded value; evaporative cooler
Net Plant Capacity - Summer/Winter Avg. (MW)	219.95	219.65	Avg. degraded value.
Net Plant Capacity - Summer DMNC (MW)	211.70	211.20	Avg. degraded value; with evaporative
Net Plant Capacity - Winter DMNC (MW)	226.20	226.20	Avg. degraded value; evaporative cooler
Net Plant Capacity - ICAP (MW)	206.50	205.40	Avg. degraded value; with evaporative
Net Plant Capacity - ICAP (MW)	209.70	208.50	New and clean value; with evaporative
Net Plant Heat Rate - Summer (Btu/kWh)	10,708	10,705	Avg. degraded value; with evaporative
Net Plant Heat Rate - Winter (Btu/kWh)	10,248	10,259	Avg. degraded value; evaporative cooler
Net Plant Heat Rate - Summer/Winter Avg. (Btu/kWh)	10,478	10,482	Avg. degraded value.
Net Plant Heat Rate - Summer DMNC (Btu/kWh)	10,720	10,718	Avg. degraded value; with evaporative
Net Plant Heat Rate - Winter DMNC (Btu/kWhW)	10,241	10,249	Avg. degraded value; evaporative cooler
Net Plant Heat Rate - ICAP (Btu/kWh)	10,764	10,765	Avg. degraded value; with evaporative
Net Plant Heat Rate - ICAP (Btu/kWh)	10,603	10,604	New and clean value; with evaporative
Equivalent Forced Outage Rate - Demand Based	2.17%	2.17%	Long-term average.
Natural Gas Consumed During Start (mmBtu/start, per Unit)	450	450	Cold start for simple cycle. Warm start for combined cycle, thru steam turbine
NOx emissions lb/hr per CT or per Engine			
Summer	74.9	74.9	
Winter	74.8	75.1	
Spring-Fall	76.6	76.2	
Average	75.7	75.6	
ICAP	73.1	72.6	
CO2 emissions lb/hr per CT or per Engine			
Summer	262,964	262,063	
Winter	270,388	264,484	
Spring-Fall	271,491	269,999	
Average	269,084	266,636	
ICAP	256,001	254,552	
CO2 emissions lb/MW-hr (gross) per CT or per Engine			
Summer	1,200	1,199	
Winter	1,165	1,140	
Spring-Fall	1,203	1,203	
Average	1,193	1,186	
ICAP	1,209	1,209	

Combustion Turbine Model	Zone F (Alb - Simple Cycle) Simple Cycle SGT6-5000F(5)	Zone C (Syr - Simple Cycle) Simple Cycle SGT6-5000F(5)	Comments
Fixed O&M ($/year)			
Labor - Routine O&M	882,000	816,000	
Materials and Contract Services - Routine	308,000	300,000	
Fuel Oil Testing	0	0	
Administrative and General	335,000	326,000	
Subtotal Fixed O&M	1,525,000	1,442,000	
$/kW-year	**7.38**	**7.02**	Based on net degraded ICAP capacity.
Other Fixed Costs ($/year)			
Site Leasing Costs	190,000	190,000	
Total Fixed O&M without Insurance and Property Taxes	1,715,000	1,632,000	
$/kW-year	**8.31**	**7.95**	Based on net degraded ICAP capacity.
Property Taxes (without tax abatement)	1,113,000	1,095,000	Full amount, not accounting for UTEP
Insurance	890,000	876,000	
Total Fixed O&M with Insurance and Property Taxes	3,718,000	3,603,000	
$/kW-year	**18.00**	**17.54**	Based on net degraded ICAP capacity.
Variable O&M ($/MWh)			
Major Maintenance Parts	0.00	0.00	
Major Maintenance Labor	0.00	0.00	Labor rates consistent with capital cost
Unscheduled Maintenance	-	0.00	
SCR Catalyst and Ammonia	-	-	
CO Oxidation Catalyst	-	0.40	
Other Chemicals and Consumables	0.18	0.18	
Water	0.07	0.07	
Total Variable O&M ($/MWh)	**0.25**	**0.65**	Based on net degraded summer/winter
Variable O&M - Cost per Start:			Excluding natural gas consumed (shown
Major Maintenance Parts	8,795	8,795	.
Major Maintenance Labor	369	342	Labor rates consistent with capital cost
Total ($/factored start)	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
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 - Summer DMNC (MW)	15.90	15.83	15.83	15.79	15.90	17.47	Avg. degraded value; with evaporative
Net Plant Capacity - Winter DMNC (MW)	16.62	16.62	16.62	16.62	16.62	18.26	Avg. degraded value; evaporative cooler
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. (Btu/kWh)	8,512	8,512	8,515	8,515	8,512	8,440	Avg. degraded value.
Net Plant Heat Rate - Summer DMNC (Btu/kWh)	N/A	N/A	N/A	N/A	N/A	N/A	Avg. degraded value; with evaporative
Net Plant Heat Rate - Winter DMNC (Btu/kWhW)	N/A	N/A	N/A	N/A	N/A	N/A	Avg. degraded value; evaporative cooler
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 Based	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
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	
Fuel Oil Testing	406,000	407,000	401,000	401,000	0	0	
Administrative and General	426,000	432,000	400,000	403,000	362,000	353,000	
Subtotal Fixed O&M	4,102,000	4,190,000	3,702,000	3,750,000	2,722,000	2,585,000	
$/kW-year	**21.78**	**22.25**	**19.66**	**19.91**	**14.46**	**13.06**	Based on net degraded ICAP capacity.
Other Fixed Costs ($/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	4,332,000	6,590,000	3,892,000	3,940,000	2,912,000	2,775,000	
$/kW-year	**23.01**	**35.00**	**20.67**	**20.92**	**15.46**	**14.02**	Based on net degraded ICAP capacity.
Property Taxes (without tax abatement)	3,464,000	23,386,000	3,042,000	3,123,000	2,762,000	2,725,000	Full amount, not accounting for UTEP
Insurance	2,771,000	3,031,000	2,434,000	2,498,000	2,209,000	2,180,000	
Total Fixed O&M with Insurance and Property Taxes	10,567,000	33,007,000	9,368,000	9,561,000	7,883,000	7,680,000	
$/kW-year	**56.12**	**175.29**	**49.75**	**50.77**	**41.86**	**38.80**	Based on net degraded ICAP capacity.
Variable O&M ($/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
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 ($/MWh)	**11.18**	**11.22**	**10.98**	**11.00**	**10.69**	**10.61**	Based on net degraded summer/winter
Variable O&M - Cost per Start:							Excluding natural gas consumed (shown
Major Maintenance Parts	n/a	n/a	n/a	n/a	n/a	n/a	.
Major Maintenance Labor	n/a	n/a	n/a	n/a	n/a	n/a	Labor rates consistent with capital cost
Total ($/factored start)	n/a	n/a	n/a	n/a	n/a	n/a	Factored starts include representative

* For combined cycle cases, value shown is for entire plant.

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)	G - Hudson Valley (Rockland)	F - Capital	C - Central
EPC Cost Components						
Equipment						
Equipment	116,520,000	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	117,646,000	119,005,000	118,587,000	118,587,000	115,345,000	108,679,000
Construction						
Construction Labor & Materials	88,655,000	95,658,000	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 & Delivera	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	4,047,000	7,523,000	3,292,000	3,440,000	2,768,000	2,700,000
Engineering & Design	11,569,000	12,227,000	10,433,000	10,721,000	9,688,000	9,098,000
Construction Mgmt. / Field Engr.	2,892,000	3,057,000	2,608,000	2,681,000	2,422,000	2,275,000
Subtotal	127,054,000	145,167,000	103,761,000	109,442,000	91,847,000	86,880,000
Startup & Testing						
Startup & Training	1,928,000	2,038,000	1,739,000	1,787,000	1,615,000	1,516,000
Testing	-	-	-	-	-	-
Subtotal	1,928,000	2,038,000	1,739,000	1,787,000	1,615,000	1,516,000
Contingency	23,014,000	24,322,000	20,752,000	21,324,000	19,271,000	18,098,000
Subtotal - EPC Costs	269,642,000	290,532,000	244,839,000	251,140,000	228,078,000	215,173,000

	LMS100 PA - Overnight Capital Cost - 2013$s					
	K - Long Island	J - NYC	G - Hudson Valley (Dutchess)	G - Hudson Valley (Rockland)	F - Capital	C - Central
Non-EPC Cost Components						
Owner's Costs						
Permitting	2,696,000	2,905,000	2,448,000	2,511,000	2,281,000	2,152,000
Legal	2,696,000	2,905,000	2,448,000	2,511,000	2,281,000	2,152,000
Owner's Project Mgmt. & Misc. Eng	4,045,000	4,358,000	3,673,000	3,767,000	3,421,000	3,228,000
Fuel Oil Testing	875,000	871,000	866,000	866,000	0	0
Social Justice	539,000	2,615,000	490,000	502,000	456,000	430,000
Owner's Development Costs	8,089,000	8,716,000	7,345,000	7,534,000	6,842,000	6,455,000
Financing Fees	5,393,000	5,811,000	4,897,000	5,023,000	4,562,000	4,303,000
Studies (Fin, Env, Market, Intercon	1,348,000	1,453,000	1,224,000	1,256,000	1,140,000	1,076,000
Emission Reduction Credits	1,144,000	1,144,000	0	0	0	0
Subtotal	26,825,000	30,778,000	23,391,000	23,970,000	20,983,000	19,796,000
Financing (incl. AFUDC, IDC)						
EPC Portion	12,595,000	13,571,000	11,436,000	11,731,000	10,654,000	10,051,000
Non-EPC Portion	1,253,000	1,438,000	1,093,000	1,120,000	980,000	925,000
Working Capital and Inventories	5,321,000	5,519,000	5,046,000	5,109,000	2,281,000	2,152,000
Subtotal - Non-EPC Costs	45,994,000	51,306,000	40,966,000	41,930,000	34,898,000	32,924,000
Total Capital Investment	315,636,000	341,838,000	285,805,000	293,070,000	262,976,000	248,097,000
Cost Reduction if Single Fuel	9,625,000	9,951,000	8,371,000	8,595,000		

Table A-4 — Capital Cost Estimates for SGT6 Combined Cycle - (2013 $)

	SGT6 Combined Cycle - 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	130,523,000	132,819,000	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	131,649,000	133,945,000	133,217,000	133,217,000	129,454,000	120,263,000
Construction						
Construction Labor & Materials	225,436,000	252,671,000	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 & Delivera	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	7,597,000	15,795,000	6,146,000	6,422,000	5,388,000	5,415,000
Engineering & Design	17,912,000	19,629,000	15,177,000	15,804,000	13,794,000	12,971,000
Construction Mgmt. / Field Engr.	6,513,000	7,138,000	5,520,000	5,748,000	5,016,000	4,717,000
Subtotal	278,003,000	322,704,000	216,593,000	230,311,000	189,565,000	180,707,000
Startup & Testing						
Startup & Training	3,256,000	3,569,000	2,759,000	2,873,000	2,508,000	2,358,000
Testing	-	-	-	-	-	-
Subtotal	3,256,000	3,569,000	2,759,000	2,873,000	2,508,000	2,358,000
Contingency	39,575,000	43,370,000	33,535,000	34,918,000	30,478,000	28,658,000
Subtotal - EPC Costs	452,483,000	503,588,000	386,104,000	401,319,000	352,005,000	331,986,000

	SGT6 Combined Cycle - 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	4,525,000	5,036,000	3,861,000	4,013,000	3,520,000	3,320,000
Legal	4,525,000	5,036,000	3,861,000	4,013,000	3,520,000	3,320,000
Owner's Project Mgmt. & Misc. Eng	6,787,000	7,554,000	5,792,000	6,020,000	5,280,000	4,980,000
Fuel Oil Testing	1,103,000	1,101,000	1,093,000	1,093,000	0	0
Social Justice	905,000	4,532,000	772,000	803,000	704,000	664,000
Owner's Development Costs	13,574,000	15,108,000	11,583,000	12,040,000	10,560,000	9,960,000
Financing Fees	9,050,000	10,072,000	7,722,000	8,026,000	7,040,000	6,640,000
Studies (Fin, Env, Market, Intercon	2,262,000	2,518,000	1,931,000	2,007,000	1,760,000	1,660,000
Emission Reduction Credits	2,700,000	2,780,000	2,460,000	2,460,000	2,380,000	1,230,000
Subtotal	45,431,000	53,737,000	39,075,000	40,475,000	34,764,000	31,774,000
Financing (incl. AFUDC, IDC)						
EPC Portion	42,588,000	47,398,000	36,340,000	37,772,000	33,131,000	31,247,000
Non-EPC Portion	4,276,000	5,058,000	3,678,000	3,810,000	3,272,000	2,991,000
Working Capital and Inventories	7,833,000	8,339,000	7,141,000	7,293,000	3,520,000	3,320,000
Subtotal - Non-EPC Costs	100,128,000	114,532,000	86,234,000	89,350,000	74,687,000	69,332,000
Total Capital Investment	552,611,000	618,120,000	472,338,000	490,669,000	426,692,000	401,318,000
Cost Reduction if Single Fuel	9,307,000	11,762,000	8,509,000	8,640,000		

Table A-5 — Capital Cost Estimates for SGT6 Simple Cycle Without SCR - (2013 $)

	SGT6 Simple Cycle w/o SCR - Overnight Capital Cost - 2013$s	
	F - Capital (Simple Cycle)	C - Central (Simple Cycle)
EPC Cost Components		
Equipment		
Equipment	54,294,000	54,294,000
Spare Parts	1,126,000	1,126,000
Subtotal	55,420,000	55,420,000
Construction		
Construction Labor & Materials	35,459,000	33,958,000
Plant Switchyard	3,377,000	3,305,000
Electrical Interconnection & Deliver	9,573,000	9,573,000
Gas Interconnect & Reinforcement	5,395,000	5,395,000
Site Prep	2,311,000	2,202,000
Engineering & Design	4,738,000	4,654,000
Construction Mgmt. / Field Engr.	1,292,000	1,269,000
Subtotal	62,145,000	60,356,000
Startup & Testing		
Startup & Training	861,000	846,000
Testing	-	-
Subtotal	861,000	846,000
Contingency	10,233,000	10,053,000
Subtotal - EPC Costs	128,659,000	126,675,000

	SGT6 Simple Cycle w/o SCR - Overnight Capital Cost - 2013$s	
	F - Capital (Simple Cycle)	C - Central (Simple Cycle)
Non-EPC Cost Components		
Owner's Costs		
Permitting	1,287,000	1,267,000
Legal	1,287,000	1,267,000
Owner's Project Mgmt. & Misc. Eng	1,930,000	1,900,000
Fuel Oil Testing	0	0
Social Justice	257,000	253,000
Owner's Development Costs	3,860,000	3,800,000
Financing Fees	2,573,000	2,534,000
Studies (Fin, Env, Market, Intercon	643,000	633,000
Emission Reduction Credits	0	0
Subtotal	11,837,000	11,654,000
Financing (incl. AFUDC, IDC)		
EPC Portion	6,010,000	5,917,000
Non-EPC Portion	553,000	544,000
Working Capital and Inventories	1,287,000	1,267,000
Subtotal - Non-EPC Costs	19,687,000	19,382,000
Total Capital Investment	148,346,000	146,057,000

Table A-6 — Capital Cost Estimates for Reciprocating Engine - (2013 $)

	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	157,036,000	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	158,162,000	158,162,000	158,998,000	158,998,000	151,743,000	151,743,000
Construction						
Construction Labor & Materials	148,101,000	167,904,000	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 & Delivera	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	6,692,000	12,531,000	5,279,000	5,541,000	4,529,000	4,292,000
Engineering & Design	14,685,000	15,677,000	12,768,000	13,130,000	11,667,000	11,474,000
Construction Mgmt. / Field Engr.	5,874,000	6,271,000	5,107,000	5,252,000	4,667,000	4,590,000
Subtotal	197,980,000	229,085,000	152,875,000	161,234,000	134,176,000	129,730,000
Startup & Testing						
Startup & Training	2,937,000	3,135,000	2,554,000	2,626,000	2,333,000	2,295,000
Testing	-	-	-	-	-	-
Subtotal	2,937,000	3,135,000	2,554,000	2,626,000	2,333,000	2,295,000
Contingency	34,258,000	36,572,000	29,786,000	30,629,000	27,216,000	26,767,000
Subtotal - EPC Costs	393,337,000	426,954,000	344,213,000	353,487,000	315,468,000	310,535,000

	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	3,933,000	4,270,000	3,442,000	3,535,000	3,155,000	3,105,000
Legal	3,933,000	4,270,000	3,442,000	3,535,000	3,155,000	3,105,000
Owner's Project Mgmt. & Misc. Eng	5,900,000	6,404,000	5,163,000	5,302,000	4,732,000	4,658,000
Fuel Oil Testing	812,000	814,000	801,000	801,000	0	
Social Justice	787,000	3,843,000	688,000	707,000	631,000	621,000
Owner's Development Costs	11,800,000	12,809,000	10,326,000	10,605,000	9,464,000	9,316,000
Financing Fees	7,867,000	8,539,000	6,884,000	7,070,000	6,309,000	6,211,000
Studies (Fin, Env, Market, Intercon	1,967,000	2,135,000	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	42,056,000	49,519,000	37,987,000	38,842,000	33,520,000	33,871,000
Financing (incl. AFUDC, IDC)						
EPC Portion	18,129,000	19,678,000	15,865,000	16,292,000	14,540,000	14,313,000
Non-EPC Portion	1,938,000	2,282,000	1,751,000	1,790,000	1,545,000	1,561,000
Working Capital and Inventories	6,369,000	6,711,000	5,846,000	5,939,000	3,155,000	3,105,000
Subtotal - Non-EPC Costs	68,492,000	78,190,000	61,449,000	62,863,000	52,760,000	52,850,000
Total Capital Investment	461,829,000	505,144,000	405,662,000	416,350,000	368,228,000	363,385,000
Cost Reduction if Single Fuel	14,500,000	14,438,000	13,496,000	13,657,000		

Table A-7 — Comparison of Capital Cost Estimates – LMS100 in 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	95,658,000		94,244,000		68,129,000	
Electrical Connection & Substation	7,346,000		5,925,000		3,793,000	
Electrical System Upgrades	13,009,000		4,800,000		500,000	
Gas Interconnect & Reinforcement	6,347,000		5,740,000		5,000,000	
Site Prep	7,523,000		6,017,000		2,491,000	
Engineering & Design	12,227,000		11,792,000		8,562,000	
Construction Mgmt. / Field Engr.	3,057,000		2,948,000		2,140,000	
Subtotal	145,167,000		131,466,000		90,615,000	
Startup & Testing						
Startup & Training	2,038,000		1,965,000		1,427,000	
Testing	-		-		-	
Subtotal	2,038,000		1,965,000		1,427,000	
Contingency	24,322,000		23,883,000		17,031,000	
Subtotal - EPC Costs	290,532,000		276,318,000		199,123,000	
Non-EPC Cost Components						
Owner's Costs						
Permitting	2,905,000	1.00%	2,763,000	1.00%	1,991,000	1.00%
Legal	2,905,000	1.00%	5,526,000	2.00%	3,982,000	2.00%
Owner's Project Mgmt. & Misc. Eng	4,358,000	1.50%	5,526,000	2.00%	3,982,000	2.00%
Social Justice	2,615,000	0.90%	2,487,000	0.90%	2,000,000	1.00%
Owner's Development Costs	8,716,000	3.00%	8,290,000	3.00%	5,974,000	3.00%
Financing Fees	5,811,000	2.00%	956,000	0.35%	3,982,000	2.00%
Studies (Fin, Env, Market, Intercon	1,453,000	0.50%	2,764,000	1.00%	1,992,000	1.00%
Emission Reduction Credits	1,144,000	0.39%	750,000	0.27%	0	0.00%
Subtotal	30,778,000	10.59%	29,062,000	10.52%	23,903,000	12.00%
Financing (incl. AFUDC, IDC)						
EPC Portion	13,571,000	4.67%	13,844,000	5.01%	9,060,000	4.55%
Non-EPC Portion	1,438,000	0.49%	1,456,000	0.53%	1,088,000	0.55%
Working Capital and Inventories	5,519,000	1.90%	5,526,000	2.00%	3,982,000	2.00%
Subtotal - Non-EPC Costs	51,306,000	17.66%	49,888,000	18.05%	38,033,000	19.10%
Total Capital Investment	341,838,000	117.66%	326,206,000	118.05%	237,156,000	119.10%

Table A-7 — Start Up Times

LMS100

Conventional Start

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

Simple Cycle SGT6-5000F(5)

Conventional Start

Type	Total Heat Consumption	Total Time
GT Ignitiion to 100% Load	440 mmBtu (HHV)	22.3 minutes

Fast Start (30 MW/min Ramp Rate)

Type	Total Heat Consumption	Total Time
GT Ignition to 150 MW	118 mmBtu (HHV)	10 minutes
150 MW to 100% Load	90 mmBtu (HHV)	2.7 minutes
Total	208 mmBtu (HHV)	12.7 minutes

1x1x1 SGT6-5000F(5)

Conventional Start

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

Fast Start (With Purge Credit Fast Acceleration and Loading[1]

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

18V50

Conventional Start

Type	Total Heat Consumption	Total Time
Preheated[2]	11 mmBtu (LHV)	10 minutes

[1] 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.

[2] 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%	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	488,924	477,339	465,222	452,548	439,292	425,427	410,925	395,756	379,891	363,297	345,940	327,786	308,798
Principal			11,076	11,585	12,117	12,674	13,256	13,865	14,502	15,168	15,865	16,594	17,357	18,154	18,988	19,860
Interest			22,972	22,463	21,931	21,374	20,792	20,183	19,546	18,879	18,182	17,453	16,691	15,894	15,060	14,187
Balance at End of Year			488,924	477,339	465,222	452,548	439,292	425,427	410,925	395,756	379,891	363,297	345,940	327,786	308,798	288,937
EQUITY:			500,000													
TOTAL FINANCING			1,000,000													
Income Statement (Check)																
Carrying Charge Revenues:			99,528	70,340	76,921	82,863	88,296	93,288	95,871	96,308	96,700	97,244	97,678	98,267	98,748	99,386
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			22,972	22,463	21,931	21,374	20,792	20,183	19,546	18,879	18,182	17,453	16,691	15,894	15,060	14,187
Taxable Income			26,556	-47,123	-30,509	-15,511	-1,795	10,806	17,326	18,429	19,417	20,790	21,887	23,373	24,589	26,199
Income Taxes			10,520	-18,668	-12,086	-6,145	-711	4,281	6,864	7,301	7,692	8,236	8,671	9,259	9,741	10,379
Principal			11,076	11,585	12,117	12,674	13,256	13,865	14,502	15,168	15,865	16,594	17,357	18,154	18,988	19,860
Cash Flow to Equit Equity IRR =	**9.97%**	-500,000	54,960	54,960	54,960	54,960	54,960	54,960	54,960	54,960	54,960	54,960	54,960	54,960	54,960	54,960
Derivation of Carrying Charges																
Target Equity IRR =	**9.97%**															
Principal		-	11,076	11,585	12,117	12,674	13,256	13,865	14,502	15,168	15,865	16,594	17,357	18,154	18,988	19,860
Interest Expenses		-	22,972	22,463	21,931	21,374	20,792	20,183	19,546	18,879	18,182	17,453	16,691	15,894	15,060	14,187
Target Cash Flow to Equity		-	54,960	54,960	54,960	54,960	54,960	54,960	54,960	54,960	54,960	54,960	54,960	54,960	54,960	54,960
Income Taxes		-	10,520	-18,668	-12,086	-6,145	-711	4,281	6,864	7,301	7,692	8,236	8,671	9,259	9,741	10,379
Property Taxes and Insurance			0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Carrying Charges		-	99,528	70,340	76,921	82,863	88,296	93,288	95,871	96,308	96,700	97,244	97,678	98,267	98,748	99,386
Annual Rate (% of initial capital investment)			9.95%	7.03%	7.69%	8.29%	8.83%	9.33%	9.59%	9.63%	9.67%	9.72%	9.77%	9.83%	9.87%	9.94%
After-Tax Cost of Capital =	6.37%															
Present Value Factor			0.9401	0.8838	0.8308	0.7811	0.7343	0.6903	0.6489	0.6101	0.5735	0.5391	0.5068	0.4765	0.4479	0.4211
Present Value			93,565	62,164	63,909	64,721	64,833	64,395	62,213	58,753	55,458	52,429	49,508	46,823	44,233	41,852
Cumulative Present Value			93,565	155,730	219,638	284,359	349,192	413,587	475,800	534,553	590,011	642,439	691,947	738,770	783,003	824,855
Levelized Carrying Charges (Real)		102,445														
Levelized Carrying Charge Rate (Real) =		**10.24%**														

Calendar Year		2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Operating Year		15	16	17	18	19	20	21	22	23	24	25
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
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
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
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
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
Effective Income Tax Rate	39.615%	39.615%	39.615%	39.615%	39.615%	39.615%	39.615%	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
Tax Depreciation		5.910%	2.950%	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%
Depreciated Value		88,600	29,500	0	0	0	0	0	0	0	0	0
Financing												
DEBT SERVICE:												
Loan Balance Start of Year		288,937	268,164	246,437	223,712	199,942	175,080	149,076	121,878	93,430	63,674	32,552
Principal		20,773	21,727	22,726	23,770	24,862	26,004	27,199	28,448	29,755	31,122	32,552
Interest		13,275	12,320	11,322	10,278	9,186	8,044	6,849	5,599	4,292	2,925	1,496
Balance at End of Year		268,164	246,437	223,712	199,942	175,080	149,076	121,878	93,430	63,674	32,552	0
EQUITY:												
TOTAL FINANCING												
Income Statement (Check)												
Carrying Charge Revenues:		99,919	119,964	139,972	140,657	141,374	142,123	142,907	143,727	144,584	145,481	146,419
Capital Related Expenses:												
Property Taxes		0	0	0	0	0	0	0	0	0	0	0
Insurance		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
Interest Expenses		13,275	12,320	11,322	10,278	9,186	8,044	6,849	5,599	4,292	2,925	1,496
Taxable Income		27,545	78,144	128,650	130,379	132,188	134,079	136,058	138,127	140,292	142,555	144,923
Income Taxes		10,912	30,957	50,965	51,650	52,366	53,116	53,899	54,719	55,577	56,473	57,411
Principal		20,773	21,727	22,726	23,770	24,862	26,004	27,199	28,448	29,755	31,122	32,552
Cash Flow to Equit Equity IRR = **9.97%**	-500,000	54,960	54,960	54,960	54,960	54,960	54,960	54,960	54,960	54,960	54,960	54,960
Derivation of Carrying Charges												
Target Equity IRR = 9.97%												
Principal	-	20,773	21,727	22,726	23,770	24,862	26,004	27,199	28,448	29,755	31,122	32,552
Interest Expenses	-	13,275	12,320	11,322	10,278	9,186	8,044	6,849	5,599	4,292	2,925	1,496
Target Cash Flow to Equity	-	54,960	54,960	54,960	54,960	54,960	54,960	54,960	54,960	54,960	54,960	54,960
Income Taxes	-	10,912	30,957	50,965	51,650	52,366	53,116	53,899	54,719	55,577	56,473	57,411
Property Taxes and Insurance		0	0	0	0	0	0	0	0	0	0	0
Total Carrying Charges	-	99,919	119,964	139,972	140,657	141,374	142,123	142,907	143,727	144,584	145,481	146,419
Annual Rate (% of initial capital investment)		9.99%	12.00%	14.00%	14.07%	14.14%	14.21%	14.29%	14.37%	14.46%	14.55%	14.64%
After-Tax Cost of Capital = 6.37%												
Present Value Factor		0.3959	0.3722	0.3499	0.3289	0.3092	0.2907	0.2733	0.2569	0.2415	0.2270	0.2134
Present Value		39,556	44,646	48,972	46,263	43,713	41,312	39,052	36,923	34,918	33,030	31,251
Cumulative Present Value		864,411	909,057	958,029	1,004,292	1,048,005	1,089,317	1,128,369	1,165,291	1,200,209	1,233,239	1,264,490
Levelized Carrying Charges (Real)	102,445											
Levelized Carrying Charge Rate (Real) =	**10.24%**											

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:	16.93%	15.92%	15.08%	14.36%	13.74%	13.20%	12.72%	12.30%	11.93%	11.60%	11.31%	11.05%	10.82%	10.61%	10.42%	10.24%
NYC:	17.57%	16.54%	15.67%	14.93%	14.29%	13.72%	13.22%	12.78%	12.39%	12.05%	11.74%	11.47%	11.22%	11.00%	10.80%	10.62%
With Property Taxes and A07511 Tax Exemption Policy; Without Insurance:																
NYC:	17.57%	16.54%	15.67%	14.93%	14.29%	13.72%	13.40%	13.11%	12.86%	12.63%	12.43%	12.26%	12.10%	11.96%	11.83%	11.71%
With Property Taxes (no exemptions); Without Insurance:																
non-NYC:	17.68%	16.67%	15.83%	15.11%	14.49%	13.95%	13.47%	13.05%	12.68%	12.35%	12.06%	11.80%	11.57%	11.36%	11.17%	10.99%
NYC:	22.20%	21.17%	20.30%	19.56%	18.92%	18.35%	17.85%	17.41%	17.02%	16.68%	16.37%	16.10%	15.85%	15.63%	15.43%	15.25%
200 bp higher on nominal debt and equity cost:																
Without Property Taxes and Insurance:																
non-NYC:	18.74%	17.73%	16.89%	16.16%	15.54%	15.00%	14.52%	14.10%	13.73%	13.41%	13.12%	12.87%	12.64%	12.44%	12.25%	12.09%
NYC:	19.52%	18.48%	17.60%	16.85%	16.20%	15.63%	15.12%	14.68%	14.29%	13.95%	13.65%	13.38%	13.14%	12.92%	12.73%	12.55%
With Property Taxes and A07511 Tax Exemption Policy; Without Insurance:																
NYC:	19.52%	18.48%	17.60%	16.85%	16.20%	15.63%	15.28%	14.97%	14.70%	14.46%	14.25%	14.07%	13.90%	13.75%	13.61%	13.49%
With Property Taxes (no exemptions); Without Insurance:																
non-NYC:	19.49%	18.48%	17.64%	16.91%	16.29%	15.75%	15.27%	14.85%	14.48%	14.16%	13.87%	13.62%	13.39%	13.19%	13.00%	12.84%
NYC:	24.15%	23.11%	22.23%	21.48%	20.83%	20.26%	19.75%	19.31%	18.92%	18.58%	18.28%	18.01%	17.77%	17.55%	17.36%	17.18%
400 bp higher on nominal debt and equity cost:																
Without Property Taxes and Insurance:																
non-NYC:	20.61%	19.60%	18.75%	18.03%	17.41%	16.87%	16.39%	15.98%	15.62%	15.31%	15.03%	14.79%	14.57%	14.38%	14.21%	14.05%
NYC:	21.52%	20.47%	19.59%	18.83%	18.18%	17.61%	17.11%	16.67%	16.29%	15.95%	15.65%	15.39%	15.16%	14.96%	14.77%	14.61%
With Property Taxes and A07511 Tax Exemption Policy; Without Insurance:																
NYC:	21.52%	20.47%	19.59%	18.83%	18.18%	17.61%	17.25%	16.92%	16.64%	16.40%	16.18%	15.99%	15.82%	15.67%	15.54%	15.41%
With Property Taxes (no exemptions); Without Insurance:																
non-NYC:	21.36%	20.35%	19.50%	18.78%	18.16%	17.62%	17.14%	16.73%	16.37%	16.06%	15.78%	15.54%	15.32%	15.13%	14.96%	14.80%
NYC:	26.15%	25.10%	24.22%	23.46%	22.81%	22.24%	21.74%	21.30%	20.92%	20.58%	20.28%	20.02%	19.79%	19.59%	19.40%	19.23%

Debt Amortization Years =	26	27	28	29	30	31	32	33	34	35
Base Case:										
Without Property Taxes and Insurance:										
non-NYC:	10.09%	9.95%	9.82%	9.70%	9.59%	9.49%	9.39%	9.31%	9.23%	9.15%
NYC:	10.46%	10.31%	10.17%	10.05%	9.93%	9.82%	9.73%	9.63%	9.55%	9.47%
With Property Taxes and A07511 Tax Exemption Policy; Without Insurance:										
NYC:	11.60%	11.51%	11.42%	11.34%	11.26%	11.19%	11.13%	11.07%	11.01%	10.96%
With Property Taxes (no exemptions); Without Insurance:										
non-NYC:	10.84%	10.70%	10.57%	10.45%	10.34%	10.24%	10.14%	10.06%	9.98%	9.90%
NYC:	15.09%	14.94%	14.80%	14.68%	14.56%	14.45%	14.35%	14.26%	14.18%	14.10%
200 bp higher on nominal debt and equity cost:										
Without Property Taxes and Insurance:										
non-NYC:	11.94%	11.81%	11.68%	11.57%	11.47%	11.38%	11.29%	11.21%	11.14%	11.07%
NYC:	12.40%	12.25%	12.12%	12.00%	11.89%	11.79%	11.70%	11.62%	11.54%	11.47%
With Property Taxes and A07511 Tax Exemption Policy; Without Insurance:										
NYC:	13.38%	13.28%	13.19%	13.11%	13.03%	12.96%	12.90%	12.84%	12.78%	12.73%
With Property Taxes (no exemptions); Without Insurance:										
non-NYC:	12.69%	12.56%	12.43%	12.32%	12.22%	12.13%	12.04%	11.96%	11.89%	11.82%
NYC:	17.02%	16.88%	16.75%	16.63%	16.52%	16.42%	16.33%	16.25%	16.17%	16.10%
400 bp higher on nominal debt and equity cost:										
Without Property Taxes and Insurance:										
non-NYC:	13.91%	13.79%	13.68%	13.57%	13.48%	13.40%	13.32%	13.25%	13.19%	13.13%
NYC:	14.46%	14.32%	14.20%	14.09%	13.99%	13.90%	13.81%	13.74%	13.67%	13.60%
With Property Taxes and A07511 Tax Exemption Policy; Without Insurance:										
NYC:	15.30%	15.20%	15.11%	15.03%	14.96%	14.89%	14.83%	14.77%	14.72%	14.67%
With Property Taxes (no exemptions); Without Insurance:										
non-NYC:	14.66%	14.54%	14.43%	14.32%	14.23%	14.15%	14.07%	14.00%	13.94%	13.88%
NYC:	19.09%	18.95%	18.83%	18.72%	18.62%	18.53%	18.44%	18.37%	18.30%	18.23%

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:	17.18%	16.20%	15.38%	14.69%	14.09%	13.56%	13.11%	12.70%	12.34%	12.01%	11.72%	11.45%	11.21%	10.99%	10.79%	10.61%
NYC:	17.89%	16.89%	16.05%	15.33%	14.72%	14.18%	13.70%	13.28%	12.90%	12.56%	12.25%	11.97%	11.71%	11.48%	11.27%	11.08%
With Property Taxes and A07511 Tax Exemption Policy; Without Insurance:																
NYC:	17.89%	16.89%	16.05%	15.33%	14.72%	14.18%	13.88%	13.61%	13.37%	13.14%	12.94%	12.76%	12.59%	12.43%	12.30%	12.17%
With Property Taxes (no exemptions); Without Insurance:																
non-NYC:	17.93%	16.95%	16.13%	15.44%	14.84%	14.31%	13.86%	13.45%	13.09%	12.76%	12.47%	12.20%	11.96%	11.74%	11.54%	11.36%
NYC:	22.52%	21.52%	20.68%	19.96%	19.35%	18.81%	18.33%	17.91%	17.53%	17.19%	16.88%	16.59%	16.34%	16.11%	15.90%	15.71%
200 bp higher on nominal debt and equity cost:																
Without Property Taxes and Insurance:																
non-NYC:	19.06%	18.07%	17.25%	16.55%	15.95%	15.43%	14.98%	14.57%	14.21%	13.89%	13.60%	13.34%	13.11%	12.90%	12.71%	12.54%
NYC:	19.90%	18.90%	18.05%	17.33%	16.71%	16.17%	15.69%	15.27%	14.89%	14.56%	14.25%	13.97%	13.72%	13.49%	13.29%	13.11%
With Property Taxes and A07511 Tax Exemption Policy; Without Insurance:																
NYC:	19.90%	18.90%	18.05%	17.33%	16.71%	16.17%	15.85%	15.56%	15.30%	15.07%	14.86%	14.66%	14.48%	14.32%	14.18%	14.05%
With Property Taxes (no exemptions); Without Insurance:																
non-NYC:	19.81%	18.82%	18.00%	17.30%	16.70%	16.18%	15.73%	15.32%	14.96%	14.64%	14.35%	14.09%	13.86%	13.65%	13.46%	13.29%
NYC:	24.53%	23.53%	22.68%	21.96%	21.34%	20.80%	20.32%	19.90%	19.52%	19.18%	18.88%	18.60%	18.35%	18.12%	17.92%	17.74%
400 bp higher on nominal debt and equity cost:																
Without Property Taxes and Insurance:																
non-NYC:	20.97%	19.99%	19.17%	18.48%	17.88%	17.37%	16.92%	16.53%	16.18%	15.86%	15.59%	15.33%	15.11%	14.91%	14.73%	14.57%
NYC:	21.97%	20.96%	20.11%	19.39%	18.77%	18.23%	17.76%	17.35%	16.97%	16.64%	16.34%	16.07%	15.83%	15.62%	15.42%	15.25%
With Property Taxes and A07511 Tax Exemption Policy; Without Insurance:																
NYC:	21.97%	20.96%	20.11%	19.39%	18.77%	18.23%	17.90%	17.60%	17.33%	17.09%	16.87%	16.67%	16.49%	16.33%	16.19%	16.06%
With Property Taxes (no exemptions); Without Insurance:																
non-NYC:	21.72%	20.74%	19.92%	19.23%	18.63%	18.12%	17.67%	17.28%	16.93%	16.61%	16.34%	16.08%	15.86%	15.66%	15.48%	15.32%
NYC:	26.60%	25.58%	24.74%	24.02%	23.40%	22.86%	22.39%	21.97%	21.60%	21.27%	20.97%	20.70%	20.46%	20.25%	20.05%	19.88%

Debt Amortization Years =	26	27	28	29	30	31	32	33	34	35
Base Case:										
Without Property Taxes and Insurance:										
non-NYC:	10.45%	10.30%	10.17%	10.05%	9.93%	9.83%	9.73%	9.64%	9.56%	9.48%
NYC:	10.91%	10.75%	10.61%	10.48%	10.36%	10.25%	10.14%	10.05%	9.96%	9.88%
With Property Taxes and A07511 Tax Exemption Policy; Without Insurance:										
NYC:	12.06%	11.95%	11.86%	11.77%	11.69%	11.61%	11.55%	11.48%	11.42%	11.37%
With Property Taxes (no exemptions); Without Insurance:										
non-NYC:	11.20%	11.05%	10.92%	10.80%	10.68%	10.58%	10.48%	10.39%	10.31%	10.23%
NYC:	15.54%	15.38%	15.24%	15.11%	14.99%	14.88%	14.77%	14.68%	14.59%	14.51%
200 bp higher on nominal debt and equity cost:										
Without Property Taxes and Insurance:										
non-NYC:	12.38%	12.24%	12.12%	12.00%	11.90%	11.80%	11.71%	11.63%	11.55%	11.48%
NYC:	12.94%	12.79%	12.66%	12.53%	12.42%	12.31%	12.22%	12.13%	12.05%	11.97%
With Property Taxes and A07511 Tax Exemption Policy; Without Insurance:										
NYC:	13.93%	13.83%	13.73%	13.64%	13.56%	13.48%	13.41%	13.35%	13.29%	13.24%
With Property Taxes (no exemptions); Without Insurance:										
non-NYC:	13.13%	12.99%	12.87%	12.75%	12.65%	12.55%	12.46%	12.38%	12.30%	12.23%
NYC:	17.57%	17.42%	17.29%	17.16%	17.05%	16.94%	16.85%	16.76%	16.68%	16.60%
400 bp higher on nominal debt and equity cost:										
Without Property Taxes and Insurance:										
non-NYC:	14.43%	14.30%	14.18%	14.08%	13.98%	13.89%	13.82%	13.74%	13.68%	13.62%
NYC:	15.09%	14.95%	14.83%	14.71%	14.61%	14.51%	14.43%	14.35%	14.27%	14.21%
With Property Taxes and A07511 Tax Exemption Policy; Without Insurance:										
NYC:	15.94%	15.84%	15.74%	15.66%	15.58%	15.50%	15.44%	15.38%	15.32%	15.27%
With Property Taxes (no exemptions); Without Insurance:										
non-NYC:	15.18%	15.05%	14.93%	14.83%	14.73%	14.64%	14.57%	14.49%	14.43%	14.37%
NYC:	19.72%	19.58%	19.46%	19.34%	19.24%	19.14%	19.05%	18.98%	18.90%	18.84%

C. Appendix 3 – STATA Output

. regress llbmpm#zc.load#zc.aggload#c.load#zc.aggload#region c.aggload2#region c.aggload3#region c.lgasp##c.lgaspc.lgasp#m#h c.ae2#region c.bay#regionh#mi.dowi.zc.tmaxc.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

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

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

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

```
                  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
                     |
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
                     |
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
                     |
 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
```

```
                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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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
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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.

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. 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.