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

NERA
Economic Consulting

Draft

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I. Executive Summary

In 2003, the NYISO implemented an Installed Capacity ("ICAP") Demand Curve mechanism. That Demand Curve is used in the ICAP Spot Market Auction conducted for each month. The ICAP Demand Curves act as bids for 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 market participants. The Demand Curve process calls for the Demand Curves to be updated every three years. The NYISO retained NERA Economic Consulting (NERA) assisted by Sargent & Lundy LLC (S&L) to perform an independent Demand Curve parameter update study applicable to Capability Years 2008/09, 2009/10 and 2010/11.

NERA was responsible for the overall conduct of the study and led the effort with respect to formulating the financial assumptions, estimating energy and ancillary services profits and developing the recommended Demand Curves. S&L was primarily responsible for developing construction cost estimates, operating cost data and plant operating characteristics. NERA and S&L collaborated to identify the potential technology choice for each region[1].

In considering the study the NYISO's Market Administration and Control Area Services, the NYISO Services Tariff ("Services Tariff") was the primary guide. In particular, we relied on Section 5.14.1(b) of that Tariff. That section of the Tariff specifies that the update shall be based upon and consider the following:

(i.) the current localized levelized embedded cost of a peaking unit in each NYCA Locality and the Rest of State to meet minimum capacity requirements;

(ii.) the likely projected annual Energy and Ancillary Services revenues of the peaking unit 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 or slightly exceed the minimum Installed Capacity requirement;

[1] The Demand Curve process calls for a Demand Curve for New York City (NYC), Long Island (LI) and rest of state (ROS). NERA and S&L developed curves for NYC, LI, the Capital Region, the Central Region and the Lower Hudson Valley. For ROS the Capital Region has been used. The Lower Hudson Valley estimate is for informational purposes only.

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(iii.) 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

(iv.) the appropriate translation of the annual net revenue requirement of the peaking unit 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 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."

The most significant issue affecting the 2007 Demand Curve update is the choice of peaking technology. It is clear that the Tariff requires the update to identify the peaking unit with the lowest fixed costs and highest variable costs that is economically viable. This unit will not necessarily be the lowest "net-cost"[2] 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 profits. 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.

As part of this study, we assumed that only a unit that could be realistically constructed in a particular location would qualify. We further assumed the Tariff to apply to reasonably large scale generating facilities that are standard and replicable, which excludes dispersed generators and special case resources.

This study examines four types of units, which between them represent two technology options. The first technology options are frame units –Frame 7EA and Frame 7FA. These are large scale combustion turbines with low capital costs and high operating costs. They are relatively inflexible with respect to starts and stops. The second are aero derivatives – the LM-6000 and LMS-100. These are more flexible combustion turbines, but have higher capital costs than frame units and have lower operating costs.

A review of these units showed the following:

[2] Net-cost refers to the difference between the annual fixed cost and annual energy and ancillary service profits

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1. The Frame 7FA has lower capital and operating costs than the Frame 7EA. The LMS-100 currently has lower capital and operating costs than the LM-6000. However, it is not clear that this will continue to be the case.

2. In comparison to the LMS-100 the capital cost of the Frame 7FA is lower and the operating cost is higher.

3. The Frame 7FA could not realistically be constructed as a peaking unit in the Lower Hudson Valley, NYC or LI. This is the case because in those particular locations a selective catalytic reduction (SCR) would be required to avoid severe operating restrictions and when operated in simple cycle mode; the Frame 7FA exhaust temperature is too hot for an SCR. Hence, a Frame 7 is not a realistic choice in the Lower Hudson Valley, NYC and LI regions.

4. There are uncertainties with respect to the costs of the LMS-100. Only one LMS-100 plant is in operation. The unit appears to offer a combination of capital and operating costs somewhere between that of a traditional peaking unit and a combined cycle unit. Currently, only General Electric offers a unit like the LMS-100, and it faces no direct competition. The base equipment price has risen by 7% in three months, which makes it very difficult to predict where the equipment will be priced during the 2008/09 – 2010/11 period. Therefore, the assessment that the LMS-100 has a lower capital cost than the 2008/09 LM-6000 may not be robust. Manufacturer price increases could lead to the LMS-100 price rising to the point where the LMS-100 installed cost exceeds that of the LM-6000. Manufacturer price decreases could lead to the price of the LM-6000 declining below that of the LMS-100. At this point in the LMS-100 life cycle it is too early to know if the LMS-100 will render the LM-6000 obsolete, except where its smaller size is required, as the LMS-100 will continue to have lower capital and operating costs, or whether as the LMS-100 gains experience and acceptance, the prices will adjust so that LM-6000 has a lower capital cost to offset its heat rate disadvantage

In the 2004 Demand Curve update, the NYISO used a Frame 7FA for its NYCA Demand Curve and a LM-6000 for the NYC and LI Demand Curves. The LMS-100 was not available at that time. In order to put the current update into perspective, below is a comparison between the costs used in 2004 and the current update holding technology constant.

Table I.1. Demand Curve Values at Reference Point:
Values for Capacity Years 2007/08 and 2008/09

		2004 Update for 2007 2008 dollars/kW-Year			*2007 Update for 2008 2008 dollars/kW-Year*		
		Annual Fixed Cost	Energy and AS Profits	Net Costs	Annual Fixed Cost	Energy and AS Profits	Net Costs
ROS	Frame 7	$94.79	$20.70	**$74.09**	$107.89	$17.87	**$90.03**
NYC	LM-6000	$191.76	$52.30	**$139.46**	$240.08	$65.06	**$175.01**
LI	LM-6000	$168.88	$41.40	**$127.48**	$214.87	$72.43	**$142.44**

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We present the values above in 2008 dollars as the curve will be started on that basis. As can be seen above, all else equal, the Demand Curve would increase significantly. This is the result of a combination of factors including:

1. an increase in construction and equipment costs resulting from market conditions;
2. a change in the carrying charge methodology that effectively shortens the 20 year amortization period used in the prior study but that in NYC is offset by a lower property tax rate assumption; and
3. for LI these are partially offset by significant increases in estimated energy and ancillary services profits.

A comparison of the installed cost per ICAP kW and the effective amortization period used is presented below.

Table I.2. Capital Costs and Amortization Periods
Values for Capacity Years 2007/08 and 2008/09

		2004 Update 2008 dollars		*2007 Update 2008 dollars*	
		Installed Cost per ICAP kW ($/kW)	Amortization Period (Years	Installed Cost per ICAP kW ($/kW)	Amortization Period (Years)
ROS	Frame 7 x 2	666	**20**	689	**14.5**
NYC	LM-6000 x 2	1,322	**20**	1,523	**13.5**
LI	LM-6000 x 2	1,253	**20**	1,484	**18.5**

Holding technology and the Demand Curve zero crossing point constant the unit capital cost would increase in all regions by more than inflation. This is attributable to increased construction costs and increased recognition of merchant risk through the use of shorter amortization periods.

As discussed above, the LMS-100 has emerged as a technology alternative. The LMS-100 currently has lower capital and lower operating costs than the LM-6000, but as previously discussed, that situation may not be robust.

Table I.3. Demand Curve Values at Reference Point:

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Values for Capacity Years 2007/08 and 2008/09

		2004 Update for 2007 *2008 dollars*			*2007 Update for 2008* *2008 dollars*		
		Annual Fixed Cost	Energy and AS Profits	Net Costs	Annual Fixed Cost	Energy and AS Profits	Net Costs
ROS	Frame 7 x 2	94.79	20.7	**74.09**	107.89	17.87	**90.03**
NYC	LM-6000 x 2	191.76	52.3	**139.46**	240.08	65.06	**175.01**
	LMS-100 x 2				181.18	74.09	**107.09**
LI	LM-6000 x 2	168.88	41.4	**127.48**	214.87	72.43	**142.44**
	LMS-100 x 2				159.19	88.35	**70.84**

The LMS-100 has a relatively efficient heat rate (9100 BTU/kWh HHV) and, hence, is able to capture very significant energy profits. All the results discussed to this point reflect the existing zero-crossing points. The issue of Demand Curve slope will be addressed later. The methodology integrates slope and cost as higher slopes increase merchant risk.

We recognize that continuity is important to the Demand Curve process. Since the recommendations we are making herein incorporate several major changes, we will review and explain the rationale behind each major change.

New Technology – The LMS-100 has emerged as a technology alternative. While the LM-6000 has an extensive application in electricity generation, with more than 200 in commercial operation, the LMS100 is a relatively new machine with little operating history. The only unit in commercial operation, installed in 2006, is located at Basin Electric Power Cooperative's Groton Generation Station in Groton, South Dakota. Discussions between S&L and Basin Electric indicate that the unit has been operating without any recurring issues or major problems other than a generator bearing replacement with reliability trending up. Sargent and Lundy have made a site visit to Basin Electric and is monitoring performance.

The uncertainty in the LMS-100 cost and performance estimates for this report should not be technically different from those of the LM-6000. Major components of the LMS-100 technology are based on both Frame 7 and LM-6000 designs. The gas turbine in the LMS-100 has over 100 million

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hours of operating experience in both aircraft engines and industrial applications. The construction process and requirements for the LMS-100 are similar to those of either frame or aero derivative units; hence, the contingency factor in the cost estimates need not be increased. There is no known technical basis for excluding the LMS-100 from consideration at this time. Nonetheless, actual LMS-100 performance is not demonstrated by a vast experience base though some merchant generators may be willing to take the LMS-100 technology risk. As discussed above, the LMS-100 has a substantially lower heat rate than the LM-6000 and faces no direct manufacturing competition. Equipment prices have increased sharply recently and there is no way to tell whether or not such increases will continue and if introductory pricing was promotional. If the equipment price continues to escalate and if LM-6000 demand falls and LM-6000 prices drop, the LMS-100 could become more expensive in installed costs terms than the LM-6000. The Demand Curve has been developed for both the LM-6000 and LMS-100 in areas of the state where it is not feasible to install a Frame 7 FA.

Construction Costs – Construction costs changes, while significant, are explainable and reflect market changes. LM-6000 and Frame 7 FA construction costs have increased by more than inflation, but these result from increases in material and construction costs that are well known. The corresponding LMS-100 costs are derivable based on LM-6000 figures due to similarities in site requirements and construction methods.

Carrying Charges – The 2004 update used a 50/50 capital structure with a debt cost of 7.5% and an equity cost of 12.5%. The current update uses very similar costs – i.e., 50/50 capital structure with a debt cost of 7.0% and an equity cost of 12.0%. However, the previous study used a 20-year amortization period for all regions. In the current study we introduce a new methodology that determines the amortization period considering the risk of excess capacity, other risks which we discuss later and the Demand Curve slope. The result, given no change to the Demand Curve slope is a reduction in the NYC amortization period to about 13.5 years, in the ROS period to about 14.5 years, and in Long Island about 18.5 years. This increases carrying charges. The difference by region reflects the risk difference resulting from the slope of the Demand Curve and slope of the energy and ancillary service profit function. We believe that this change in method is necessary as the method used 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. As there exists a bias towards excess capacity, a steeper slope requires a higher carrying charge to compensate

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for lower prices in excess capacity periods. In both studies the capital structure and cost of capital reflect a sound company with moderate risk and an investment grade rating. The Demand Curve is predicated on more risky merchant development.[3] Hence, not having increased the cost of capital to allocate for merchant risk, we believe that it is necessary to reflect merchant risk in the cost and do so through a shortening of the recovery period. We would recommend that the method used to develop the Demand Curve be made a permanent feature of the Demand Curve update process.

Energy and Ancillary Service Revenues – The estimates that we use here for NYC energy profits are about similar to those in the last update. For LMS-100 facilities we use energy revenues on the 345 kV system as the units may be too large for location in areas where they could obtain load pocket prices. We obtain significantly higher energy revenues on Long Island. This is consistent with price data which show LI energy prices to exceed prices in NYC. Compared to the 2004 update, we obtain lower energy revenues upstate and slightly higher revenues in NYC. We believe that the decrease upstate is caused by explicitly modeling the maintenance related start-up costs of the Frame 7 units. Except for statistical adjustments to correct profits for reserve levels, the energy profits we use are reflective of those that realistically could have been achieved over the past 3.5 years as they are based on actual prices for the past 3.5 years. This lends objectivity to the estimates. The statistical analyses demonstrated that the system changes in New York City (e.g., the addition of roughly 1,000 MW of combined-cycle capacity) had a very minor impact on energy prices. Hence, we did not explicitly adjust for this change, but capture its effect through the reserve margin variable. It is possible that any effect in part is obscured by improvements in the pricing algorithm which raise prices.

Our original intent was to develop the estimates of energy and ancillary service profits using a Monte Carlo representation of weather and fuel prices over the next three years. This proved not to be possible. Extensive and detailed calculations were done to reflect the operating constraints of the combustion turbine equipment and the interactions between real time and day-ahead prices. These calculations were not feasible in a Monte Carlo model that treated weather and fuel price probabilistically. Hence, the energy profits we have developed reflect actual weather and gas prices over the past 3.5 years and reflect a detailed modeling of realistic equipment operation and day-ahead and real time market interactions.

[3] The tariff calls for the localized levelized embedded cost. We interpret levelized to mean levelized using parameters that reflect the risk of merchant generation or generation that will face spot market prices.

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Demand Curve Development – 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 market participants in executable form.

The model recognizes that the NYISO has in place planning and response procedures to prevent capacity from falling short. Hence, there should over time be a bias toward surplus capacity conditions. If there is expected to be surplus capacity, the Demand Curve must be adjusted to reflect the fact that over time the expected clearing price would be below the target reserve point. Absent such as adjustment, the Demand Curve would not produce adequate expected revenues to recover cost and would not induce the proper level of investment. Additionally, there has historically been a real decline in generating plant costs reflecting technical progress and we would expect future Demand Curves to reflect this decline. The current Demand Curve would produce inadequate revenue if this was not accounted for.

The model we have developed to set the Demand Curve accounts for these factors. As an example, the effective real levelized carrying charge developed from the risk analysis and used to set the Demand Curve reference point is 13.71-14.40% for NYC and 15.12% for ROS. ROS is higher because the Demand Curve has a steeper slope (crossing at 12% rather 18% above the reference). Over 20 years the non risk adjusted carrying charges would be 12.75% for ROS and 12.61% for NYC. Hence, the risk adjustment has a significant impact on the levelization of construction cost and on the Demand Curve. The carrying charge difference between the 30 year values can be viewed as the merchant risk. The merchant risk premium for NYC is also lower because in the first 15 years, new generation in NYC pays no property taxes. This enables more revenue to go toward the return of and return on capital.

The table below translates the carrying charge used to determine the basis point premium in WACC over 20 years and 30 years.

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Table II.3. Translation to Basis Premium

		Carrying Charge	WACC Premium on 20-Year Amortization	WACC Premium on 30-Year Amortization
ROS	Frame 7 x 2	14.99%	229	399
NYC	LM-6000 x 2	14.40%	207	336
	LMS-100 x 2	13.71%	132	260
LI	LM-6000 x 2	13.36%	55	233
	LMS-100 x 2	12.36%	-52	132

To reemphasize, all values discussed to this point use the current Demand Curve shape. However, when using the risk model, the slope of the Demand Curve has a measurable influence on the 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 less steep slope. To provide the same expected revenue over the life of the investment, a higher reference point must accompany a steeper slope. For example, if the NYC slope was applied to the ROS Demand Curve the reference value would fall by $6.62 per kW year.

In the 2004 update, the Demand Curves slopes were reviewed. The review concluded that the zero crossing portion of 112% for ROS and 118% for NYC and LI be retained. However, the review did find that steeper curves provide greater incentive to withhold and that shallower curves can lead to lower total capacity costs because the reduced incentive to withhold and lower price more than compensation for the higher level of purchase. The incentive to withhold was identified as greatest in Zone J as the result of greater concentration in Zone J. The slope is both a function of the zero crossing point and the CONE at the reference capacity level. The higher the reference CONE, the greater the slope for the same zero crossing point. Given the recent controversy over potential withholding in NYC spot capacity auctions and mitigation issues, we do not recommend increasing the slope by moving the zero crossing point closer to the origin. If the LMS-100 is selected and the zero crossing point is kept at 118%, the slope will stay approximately the same. If the LM-6000 is selected as the peaking unit, maintaining the 118% zero crossing point will increase the Demand Curve slope. That slope is already creating controversy with respect to withholding. Hence we recommend

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retaining the 118% zero crossing point. However, we do not recommend moving the zero crossing point beyond 118% as it is reasonably clear that capacity has little value at or beyond that point.

The LI market is different than the other two regions. It has one dominant load serving entity with most supply under contract. Maintaining the zero crossing point at 118% and letting the slope increase would be reasonable.

There is no reason why the Demand Curve must be a single straight line from the maximum value of 1.5 times the reference point to the zero crossing point. We also examined a "kinked" Demand Curve. This type of curve has a relatively lower slope (i.e. it is flatter) from the reference point and becomes steeper (hence the kink) at a point close to the zero-crossing point. There are pros and cons to such a curve. On the pro side, it reduces the reference point as it reduces the impact of the most likely condition which is a modest capacity excess. This does however come at a cost. The incentive to add during shortage condition is reduced as the curve is less steep on both sides of the reference point. It also reduces the incentive to withhold when total capacity falls into the flat segment of the curve. Further, by going to the zero crossing point more quickly it will eliminate capacity payments if there are large chronic excesses when such payments would persist, albeit at low levels, with a single flatter curve that crosses zero further from the reference point.

According to the Tariff, the Demand Curve is not based on the lowest net-cost unit, but on the net-cost of an economically viable unit with the lowest fixed cost and highest operating (or variable) cost. Therefore, if a baseload unit were to be installed it is possible that it could cause a surplus of capacity and, due to greater efficiency, it could be profitable without capacity revenue. Under the single slope Demand Curve which extends well beyond the reference point, customers may pay capacity payments even when such surpluses develop and capacity revenue is not needed to induce entry. Under a kinked Demand Curve, payments will decline to zero faster and capacity payments are more likely to be eliminated if they are not required to induce entry by base-load plant. This effect could however be offset by a higher incentive to withhold capacity if supply falls into the steeply sloped area of the kinked Demand Curve. Hence, a kinked Demand Curve is likely to be effective only when capacity withholding is prohibited or mitigated. Further, a Demand Curve that declines to zero more rapidly could lead to mothballing and retirement of less efficient existing capacity. We have developed kinked Demand Curve for each region in addition to traditional curves. The kinked curves have a first

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segment that extends from the reference point to a point 33% above the reference level. The curve kinks at six percent above the reference level and descends to zero at 12% above the reference level. This slope would drop the reference price for ROS by about 12.5% and would drop the NYC reference price by about 7.4%. In return for the lower reference price and quicker drop to zero, prices would decline less sharply during the periods of modest surplus that are the most likely conditions and rise less steeply during shortage conditions.

We do not recommend kinked Demand Curves for two reasons. First, there is a very strong incentive to withhold when supply conditions are close to the kink. Second, the interaction between winter capacity and the kink is complex and has not been analyzed. A kink around 106%, could easily force prices in the winter down to near zero. This would need to be offset by an increase in the reference value. However, it would add uncertainty and create the strong potential for setting a curve that either systematically over or under compensated generators. We would recommend looking again at a kinked curve, when the summer/winter adjustment is stable and more time can be dedicated to analyzing the combined effects of withholding, the summer/winter adjustment and potential excess capacity. While a kink further out, say at 110% may be feasible, by that point the impact of the kink is likely to be very small.

In making the Demand Curve recommendation we have been influenced by the value of stability. The zero crossing points are reasonable and there is no compelling reason for a change. Given the significant changes in construction cost, we believe that changes to the zero crossing point that do not provide for a clearly better Demand Curve are not warranted.

Recommended Demand Curves – The recommended Demand Curves are presented below. For each region the chart shows the current Demand Curve, the 2008/09 recommendation for a single segment Demand Curve and the current curve. Both LM 6000 and LMS 100 curves are shown for NYC and LI.

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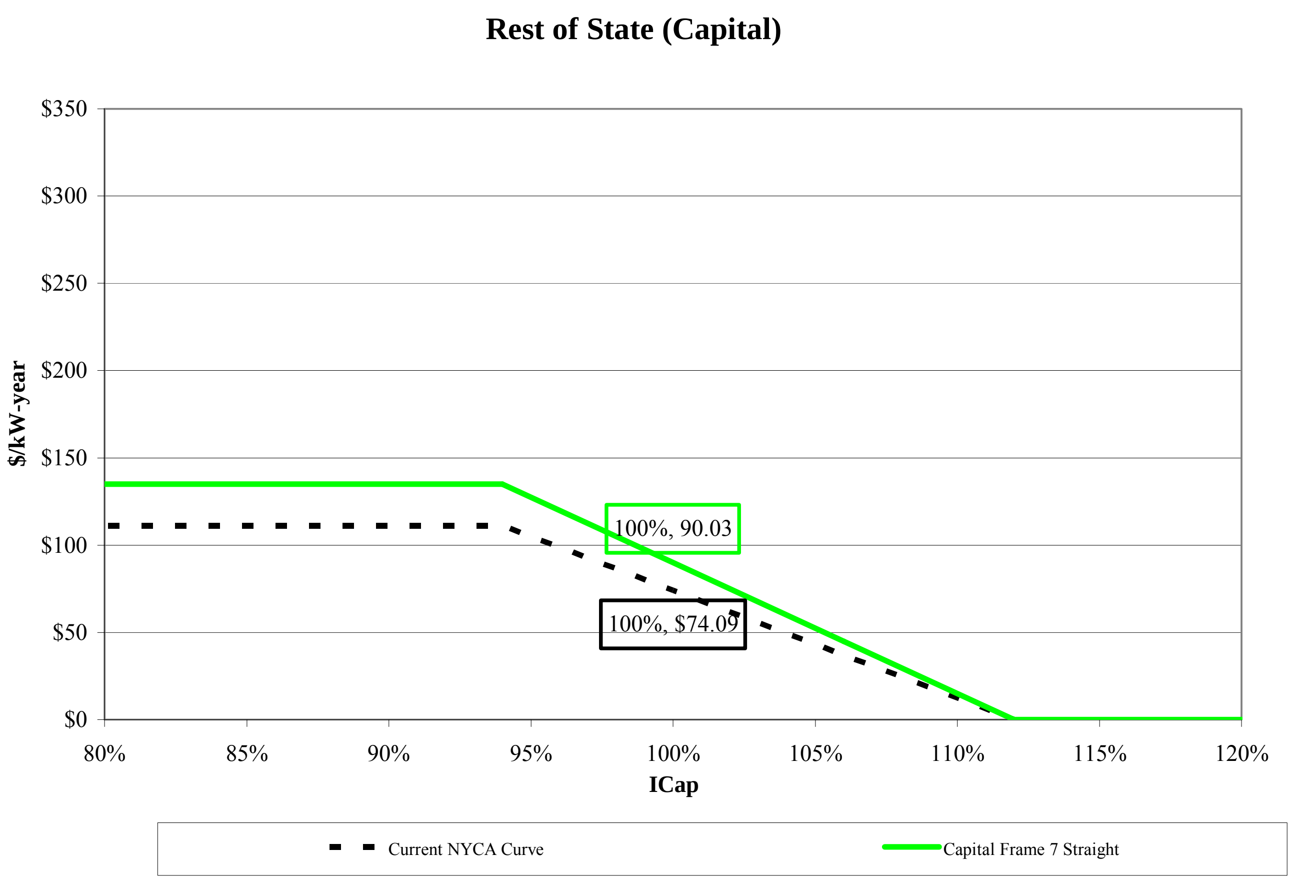
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85%
90%
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ICap
100%, 90.03
100%, $74.09
Current NYCA Curve
Capital Frame 7 Straight

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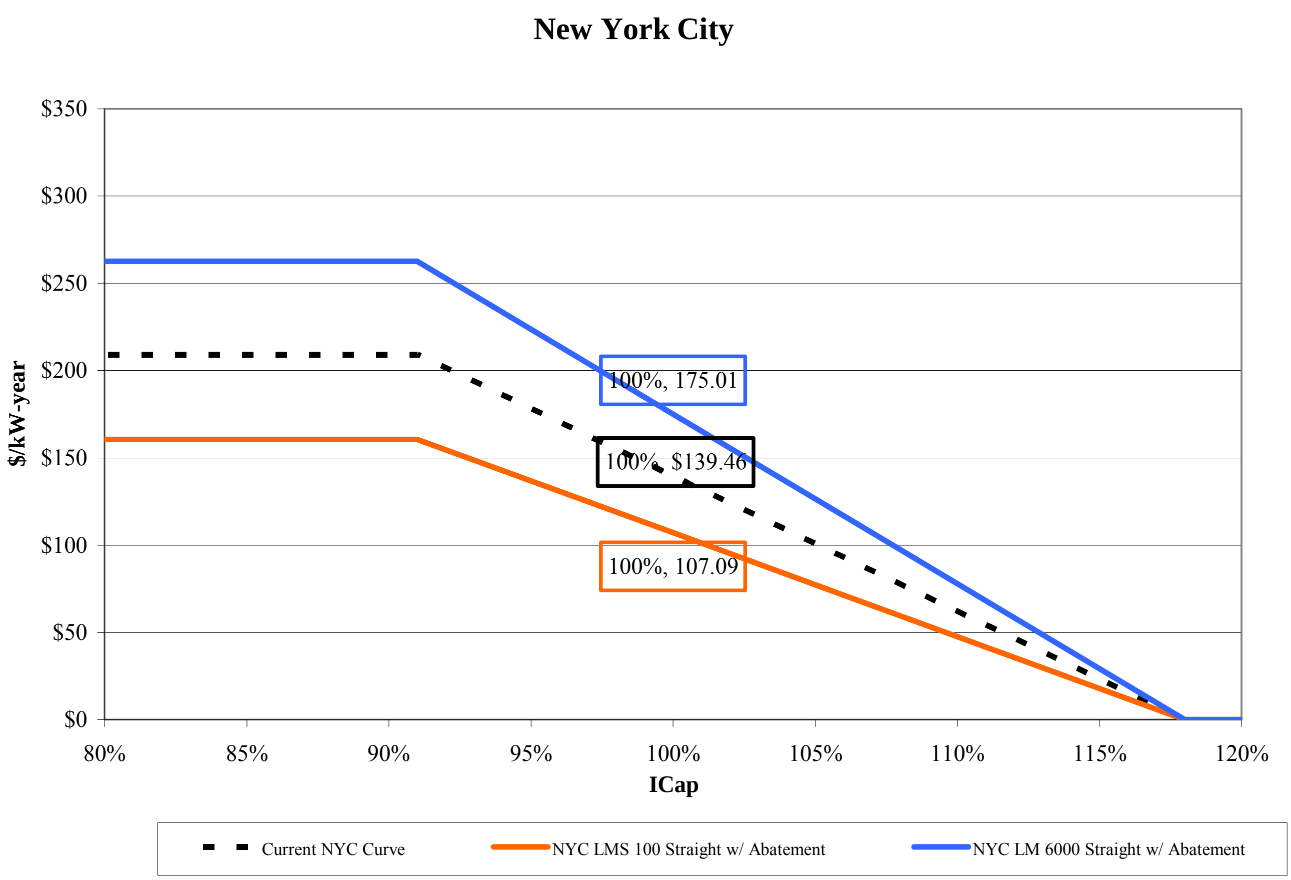
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85%
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100%
105%
110%
115%
120%
ICap
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Current NYC Curve
NYC LMS 100 Straight w/ Abatement
NYC LM 6000 Straight w/ Abatement

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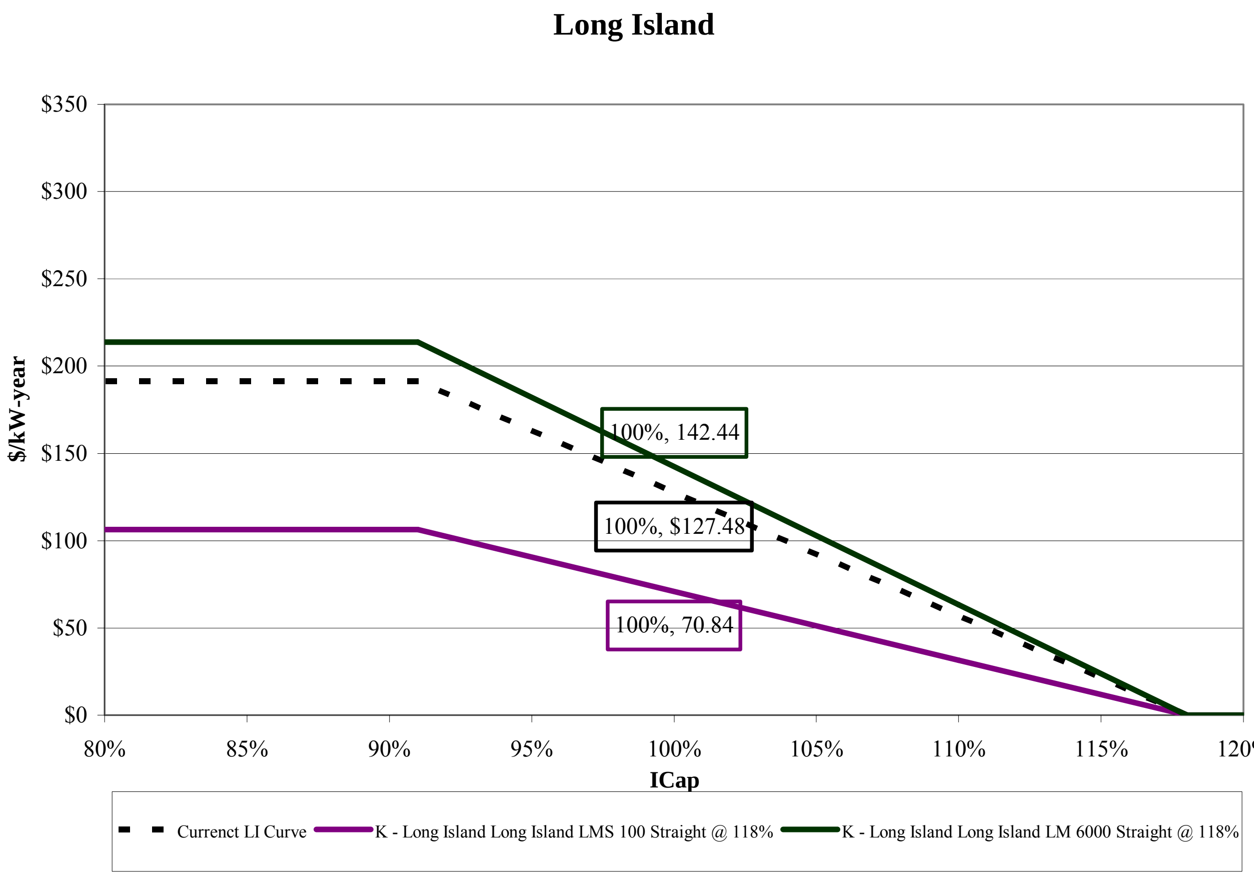

Mitigation Impacts – The analyses described above have been conducted assuming that markets are strictly mitigated and that withholding incentives are weak and/or withholding is not effective as a result of mitigation. This assumption is reasonable for ROS and Long Island. As recent controversy indicates, it is not necessarily the case for New York City. If it was assumed that despite a tendency for there to be moderate excess capacity in NYC, generators could effectively maintain the Demand Curve price at the reference point, the reference value for the LM-6000 would decline from $175.01 kW to $144.44 kW as a substantial portion of merchant risk would be eliminated. This curve is shown below. However, for this to be relevant, the entities with the largest share of in city generation (the Divested Generators Owners, or DGOS) would need to benefit from withholding Given the increase in the CONE at the reference point, and the fact that it is above the DGO price cap of $105 kW year, this appears unlikely to be applicable.

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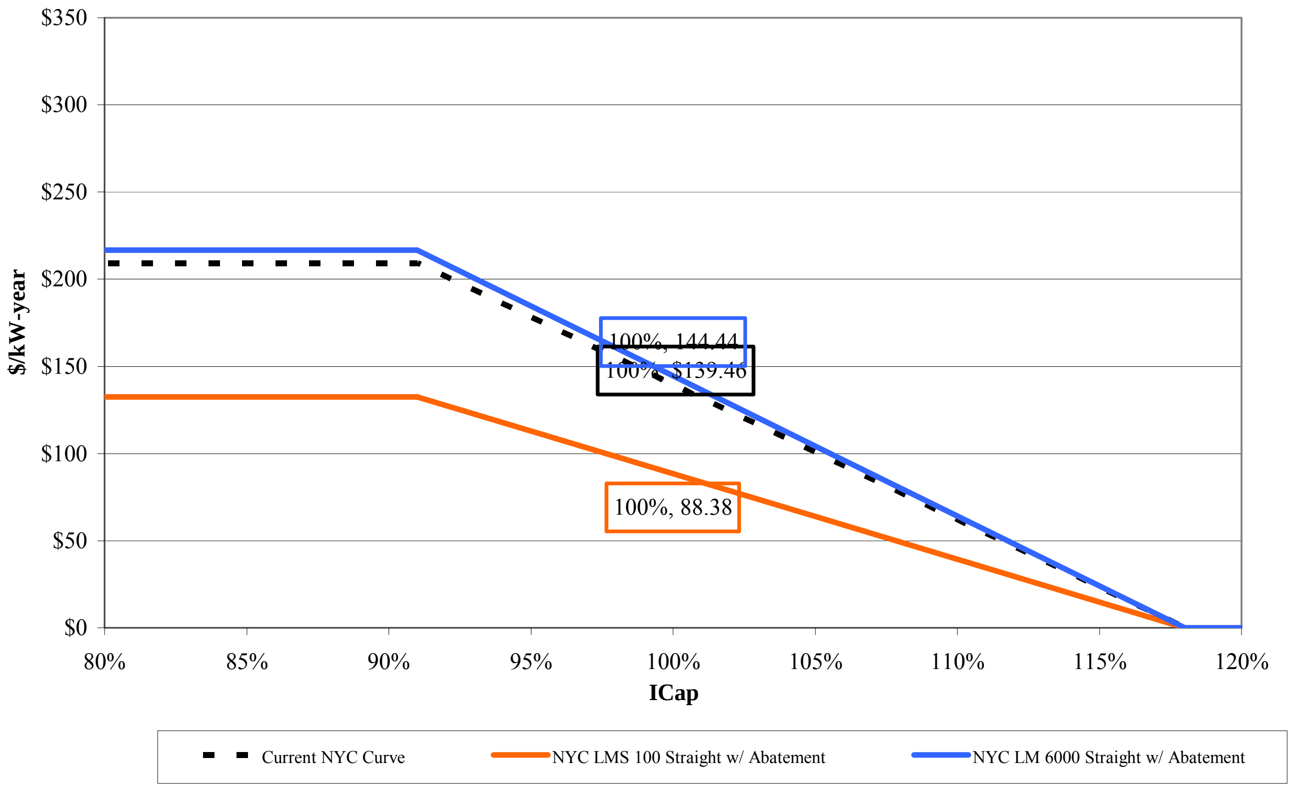
NYC with Withholding Maintaining Capacity at Reference Value



II. Technology Choice and Construction Cost

The installed capacity (ICAP) Demand Curve is derived from the levelized cost of a hypothetical new peaking unit at various locations throughout the state of New York. The reference peaking facility is a gas-fired combustion turbine operating in simple-cycle mode. A range of combustion turbine options, based upon recent peaking applications and design requirements, 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.

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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 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. Tariff Requirements

The 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."

It is clear from the Tariff language that the requirement is to identify the lowest fixed cost, highest variable cost peaking unit that is economically viable. This unit will not necessarily be the lowest "net-cost" 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 profits.

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. For purposes of this study, we assume that only a unit that could be realistically constructed in a locality would qualify. We also assumed the Tariff to apply to reasonably large scale generating facilitates that are standard and replaceable, which excludes dispersed generators and special case resources.

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B. Alternate Technologies Examined

In conducting the study, two types of peaking units were examined and, within each type, two technologies.[4]

The first type was the heavy-duty frame units: the 7EA and 7FA. These are large-scale combustion turbines oriented to industrial applications with lower capital costs (on a $/kW basis) and higher operating costs (on a $/MWh basis). Maintenance costs are affected by the duty cycle experienced in operations. As a unit is subjected to more stops and starts, the time between major overhauls decreases. Nitrogen oxide (NO_X) emissions are reduced by equipping the units with dry low NO_X (DLN) combustors. Selective catalytic reduction (SCR) technology for NO_X control cannot be used because exhaust gas temperatures in simple-cycle mode exceed 850°F, above which the catalyst is damaged irreversibly. The efficiency of frame units can be improved by configuring units in a combined-cycle mode, where the exhaust of one or more units is directed to a heat recovery steam generator, which drives another steam turbine. This configuration was not included in the study.

The second type studied was aero derivatives: the LM6000 and LMS100. These are derived from aircraft engines and have operating characteristics that better match the needs of aircraft owners. Aero derivatives are more efficient (lower heat rate) 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, aero derivative exhaust temperatures are low enough to permit use of SCR for NO_X control.

1. 7EA

The General Electric Frame 7EA combustion turbine unit has been on the market since 1976 with over 750 units in service. The 7EA fleet has accumulated tens of millions of service hours and is recognized for high reliability and availability in both simple-cycle and combined-cycle

[4] The peaking units examined in this study are manufactured by GE Energy. The selection of these units was based on the units that were studied in the last Demand Curve Review and the comments and suggestions of ICAP Working Group members during the conduct of the study. Based on data from Platts, approximately 56% of combustion turbine capacity in the U.S. and 56% of combustion turbine capacity in the New York Control Area was manufactured by GE. There are several competing manufacturers and models for E and F frame machines and aeroderivatives. The units chosen for the study have representative cost and performance characteristics of similar products from other manufacturers. The choice of frame and aeroderivative units in this study does not constitute a recommendation from Sargent & Lundy to choose any specific manufacturer and models for projects in the New York Control Area.

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operation. The base-load 7EA gas turbines have been averaging 95%+ availability with 98%+ reliability. The 7EA is used in a wide variety of power generation, industrial and cogeneration applications. It is uncomplicated and versatile; its medium-size design lends itself to flexibility in plant layout; and can be readily converted from simple cycle to combined cycle without major modifications to the machine. With its fuel handling equipment, advanced bucket cooling, thermal barrier coatings and a multiple-fuel combustion system, the 7EA can accommodate a full range of fuels. It is designed for dual-fuel operation and able to switch from one fuel to another while the turbine is running under load or during shutdown.

2. 7FA

General Electric's installed fleet of more than 500 'F' technology combustion turbines has reached 10 million hours of commercial operation in power plants worldwide. The F technology combustion turbines were introduced in 1988. The 7FA combustion turbine, with a nominal rating of 170 MW, is capable of operating on 100% natural gas or 100% diesel fuel. DLN combustors reduce NO_X emissions. Water injection is used for NO_X control in the combustion process when firing diesel fuel. The wide range of power generation applications for the 7FA gas turbine include combined cycle, cogeneration, simple-cycle peaking and integrated gasification combined cycle (IGCC) in both cyclic and base-load operation with a wide range of fuels. The reliability of the 7FA gas turbine has been consistently 98% or better.

3. LM6000

Since the introduction of the LM6000 into GE's aeroderivative combustion turbine product line, GE has produced more than 300 units, of which more than 200 are in commercial operation. The turbine has a 12-month rolling average engine availability of 96.8% and engine reliability of 98.8%, based on more than 3.1 million operating hours. The LM6000 is a dual-rotor, "direct drive" combustion turbine, which was derived from GE's CF6-80C2, high-bypass, turbofan aircraft engine. The combustion turbine reduces NO_X emissions levels by using a single annular combustion system with water injection to limit the formation of NO_X during the combustion process. For this study, the LM6000 was configured with SPRINT™ (Spray Inter-cooled Turbine) technology to significantly enhance power.

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4. 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 low-pressure compressor (LPC), based on the 6FA, pumps 1.7 times the LM6000™ airflow. The airflow 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.

Unlike the other technologies, the LMS100 is a relatively new machine with little operating history. The only unit in commercial operation is located at Basin Electric Power Cooperative's Groton Generation Station in Groton, South Dakota. The unit has been in commercial operation since July 2006. The unit has been operating without any recurring issues or major problems other than a generator bearing replacement, with reliability trending up[5]. As of April 22, 2007, there have been 584 hours of operation and 107 starts[6]. Basin Electric ordered a second unit, which has been shipped to the site. GE reported to S&L in May 2007 that at least 13 other units have been sold: 2 in Canada and 11 in California. There are published reports of additional LMS100s planned at other locations in North America.

The uncertainty in the LMS100 cost and performance estimates for this report are not different from those of the LM6000 (except for equipment prices, which is discussed below). As discussed previously, major components of the LMS100 technology are based on both 6FA and LM6000 designs. The CF6 gas turbine in the LMS100 has over 100 million hours of operating

[5] Sargent & Lundy staff communication, May 24, 2007.

[6] Personal communication, GE Energy, May 24, 2007.

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experience in both aircraft engines and industrial applications. The construction process and site requirements for the LMS100 are similar to those of either frame or aeroderivative units; hence, the contingency factor in the construction cost estimates need not be increased. Therefore, there is no known technical basis for excluding the LMS100 from consideration at this time.

Equipment prices for the LMS100 are difficult to predict in the short term. Quoted equipment prices for the LMS100 have increased 7% in the past three months. The lower heat rate of the unit could support a higher price for equipment without unduly suppressing demand. Other equipment manufacturers have not yet introduced models with competing features and capabilities of the LMS100. In the long run, competition from other manufacturers will limit price increases. Until competition emerges, it is possible that there will be additional equipment price increases.

5. 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 engineer, procure, and construct (EPC) contracts, and do not include owner's costs, financing costs, or working capital and inventories.

Table II.4. — Key Characteristics of Evaluated Technologies

	Heavy-Duty Frame Technologies		Aeroderivative Technologies	
	7EA	**7FA**	**LM6000 Sprint**	**LMS100**
Capacity of a 2-Unit Addition	165	330	99	200
Direct Cost ($m)	100-130	162-200	72-104	139-187
Direct Cost ($/kW)	610-780	480-600	780-1,130	690-940
Heat Rate (Btu/kWh HHV)	12,000	10,700	9,700	9,100
Pressure Ratio	12.6:1	16:1	29:1	42:1
Mass Flow (lb/sec)	640	980	290	470
Exhaust Temperature (°F)	998	1,114	826	770
Water Use (gpm)	15	30	50	60
Land Requirement	3.5?	3.5?	3.5	3.6

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	Heavy-Duty Frame Technologies		Aeroderivative Technologies	
	7EA	7FA	LM6000 Sprint	LMS100
(acres)				

The direct cost ($/kW) and heat rate data show that the 7FA had lower capital and operating cost than the 7EA, and that the LMS100 had lower capital and operating cost than the LM6000.[7] The 7FA has lower capital and higher fuel and operating costs than the LMS100. Appendix A shows more detailed information on the cost and performance characteristics of the LMS100, LM6000, and 7FA technologies . The following section addresses the impact of emissions limitations on technology choice.

C. Technology Choice by Region

All four technologies are considered to be a major source subject to Title V regulations (acid rain) because they are greater than 25 MW in capacity. The chart below shows the status of ozone non-attainment areas in New York State[8]. The amount of emissions that triggers meeting the Lowest Achievable Emissions Rates (LAER) is 25 tons per year (NO_X) in New York City, Long Island, and two counties of the lower Hudson Valley (Westchester and Lower Rockland). The threshold is 100 tons per year in other locations. SO_2 emissions are not significant from turbines using natural gas, and there no longer are carbon monoxide attainment issues in New York.

[7] However, as noted above, there is uncertainty over the price of LMS100 equipment. Should the manufacturer increase the LMS100 equipment price relative to the LM 6000, to capture the benefits of the lower LMS100 heat rate, this could change.

[8] Personal communication, NYS DEC, February 5, 2007.

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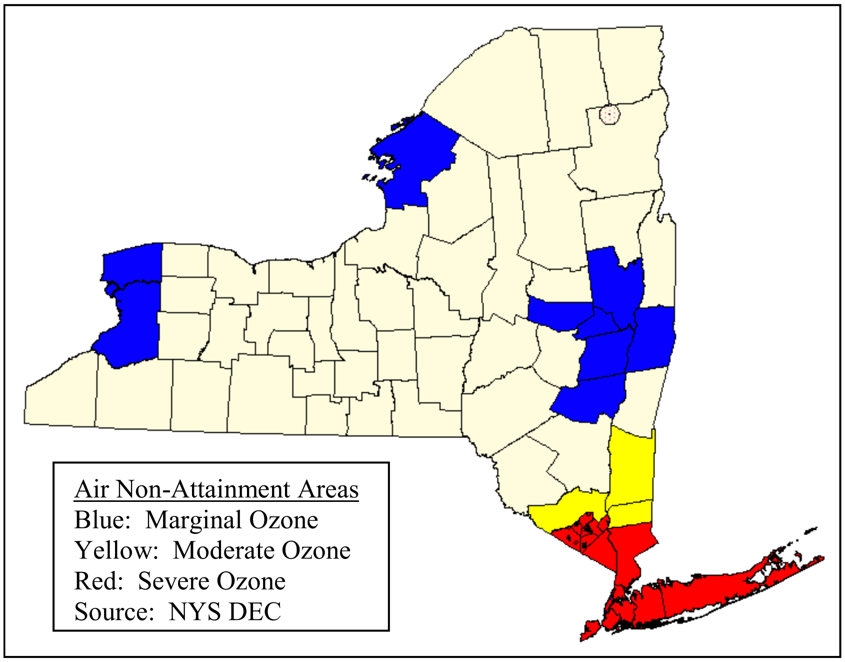
Figure II-1 — Ozone Nonattainment Areas in New York State



The table below shows estimates of the maximum annual hours of operation for the 7FA without an SCR and the LMS100 with and without an SCR. Use of an SCR on a simple-cycle 7FA is not economically or, at the present time, technically practical. S&L is not aware of any simple-cycle 7FA gas turbines with an SCR. Current, proven, SCR catalyst has a maximum operating temperature of approximately 850°F. [9] [10] 7FA gas temperatures are in excess of 1100°F (see table above). To reduce the temperature entering the SCR to 850°F, approximately 1,000,000 lb/hr of dilution air (at 59°F) would be required. The total flow entering the SCR would result in approximately 30% increased size of the SCR. Costs would increase due to the larger SCR, dilution fan, dilution ductwork and dampers, and associated controls. The dilution air fan would be about a 2 MW addition to the auxiliary power load. This additional auxiliary power, in addition to reducing unit output, increases the net heat rate by around 150 Btu/kWh.

[9] US. Environmental Protection Agency, Air Pollution Control Technology Fact Sheet, EPA-452/F-03-032

[10] GE Power Generation, "Gas Turbine NO_x Emissions Approaching Zero—Is it Worth the Price?" GER4172, September 1999.

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Table II 5. — Estimated Maximum Annual Hours of Operation for 7FA, LMS100, and LM6000

		25 Ton Limit (downstate)		100 Ton Limit (upstate)	
	NOx emissions (lbs/hr)	Maximum Annual Hours	Maximum Capacity Factor	Maximum Annual Hours	Maximum Capacity Factor
7FA w/o SCR	74	678	8%	2,712	31%
LMS100 w/o SCR	101	494	6%	1,975	23%
LM6000 w/o SCR	45	1,111	13%	4,444	51%
7FA w/SCR	Not Practical	N/A	N/A	N/A	N/A
LMS100 w/SCR	8	6,250	71%	8,760	100%
LM6000 w/SCR	5	8,760	100%	8,760	100%

A 7FA without an SCR sited downstate would be severely restricted in operating hours, but could be operated upstate with a capacity factor as high as 31%. Operation of an LMS100 or LM6000 with an SCR would not be restricted at all upstate, and not significantly affected by annual operating limits downstate.

These results show that the 7FA could not realistically be constructed as a peaker in the Lower Hudson Valley, New York City, or Long Island. In those regions, either the LMS100 or the LM6000, both with an SCR, can be operated as peaking units without environmental restrictions on operating hours.

Construction Schedule and Costs

Cost estimates were prepared for the construction of a new Greenfield two-unit simple-cycle combustion turbine peaking plant at each of five New York load zones: C, F, G, J, and K. Figure II-2 shows the location of these zones.

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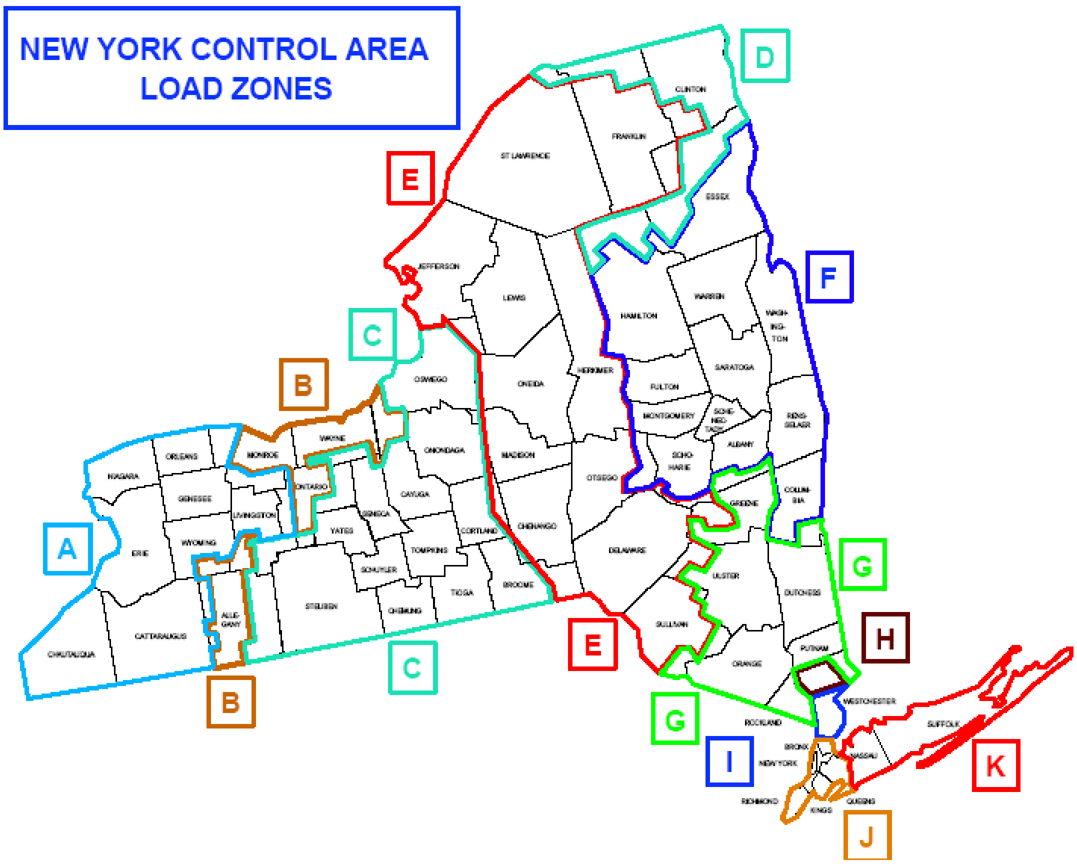
Figure II-2 — Map of New York Control Area Load Zones



These estimates reflect plant features typically found in modern peaking facilities and are intended to reflect representative costs for new plants of their type, in year 2007 dollars. The estimates are conceptual and are not based on preliminary engineering activities for any specific site. The estimates reflect projects awarded on an EPC basis, with combustion turbines and SCR systems (if included) purchased directly by the owner. Scope includes all site facilities for power generation and distribution, including a 230-kV switchyard. With no specific sites chosen for the hypothetical peaking unit of this study, a 230-kV switchyard was chosen as a compromise. Transmission systems covering small geographic areas are generally lower voltage, such as 115kV or even lower, but a peaking unit could be interconnected at a higher voltage.

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1. Principal Assumptions

The key assumptions are discussed below.

a. Technology and SCR Systems

Pursuant to the discussion in the previous section, estimates were prepared using LM6000 and LMS100 technologies with an SCR at Zones G, J, and K, and with LM6000, LMS100, and 7FA technologies without an SCR in Zones C and F. SCRs are assumed to meet a NO_X emissions limit of 2.5 ppm. A CO catalyst has not been included.

b. Greenfield Conditions

A new entrant peaking unit could be installed less expensively at an existing site where already-constructed common facilities may be utilized. Although such Brownfield sites exist, the number of these is limited. The study is based on a 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.4.

c. Number of Units

The cost per kilowatt of new capacity is reduced if multiple units are constructed and share the burden of the common facility costs. A comparison study of one, two, or four units was conducted and shows that a two-unit addition is a reasonable tradeoff between the higher cost of adding only a single unit, and the lumpier addition of four units to system capacity.

Figure II-3 — Direct Cost as a Function of Number of Units

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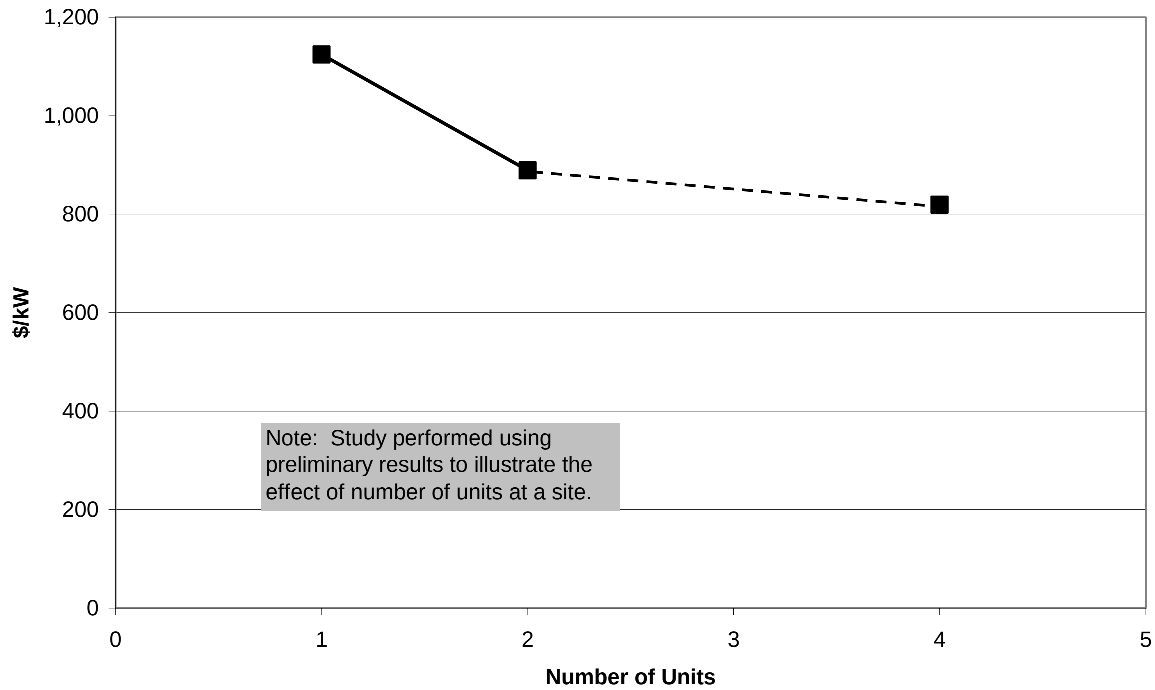
(Zone C Results for LM6000)



d. Inlet Air Cooling

Inlet air evaporative cooling (the intercooler for the LMS100) was assumed for all technologies because it increases capacity. Inlet air chillers were not included in the configuration due to cost considerations.

e. Dual vs. Single Fuel

Firing only with natural gas was assumed for this study. 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. However, current rules do not require that dual-fuel capability. Gas availability is more likely a problem in the winter when reliability is less an issue. Adding dual-fuel capability simultaneously adds capital cost while lowering operating costs.

f. Gas Compression

Fuel gas compressors have been included based on a local supply pressure of 200 psig.

g. 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 recent run-up in copper prices. A contingency of 10% was applied to the total of direct and indirect project costs.

h. 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 2007. 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 for Zone G, New York County for Zone J, and Suffolk Country for Zone K. A labor productivity adjustment of 1.38 has been applied to Zones J and K and 1.05 for other zones. 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.

i. Miscellaneous

Black start capability has not been included. Spread footing foundations without foundation piles were assumed. 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:

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— Direct costs are costs typically within the scope of an EPC contract. These costs are estimated in detail in Appendix A.

— Owner's costs include items not covered by the EPC scope such as owner's 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 11% of direct capital costs. In addition, social justice costs were estimated to be $500,000 in NYC, $375,000 in LI, and $125,000 in ROS.

— 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 A, and the cost of debt and equity presented in Section F.2. A 20-month construction period is assumed, with cash flows peaking in the 14th month. Over 70% of the total cash flow occurs in the second half of the construction period.

— Working capital and inventories refer to the initial inventories of fuel, consumables, and spare parts that are normally capitalized. It also includes working capital cash for the payment of monthly operating expenses. On the basis of recent independent power projects, these costs have been estimated as 2% of direct capital costs.

Capital investment costs for each location and combustion turbine option are summarized below in Table II.6.

Table II 6. — Capital Investment Costs for Greenfield Site (2007 $)

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	NYC 2 x LM6000 With SCR	NYC 2 x LMS100 With SCR	Long Island 2 x LM6000 With SCR	Long Island 2 x LMS100 With SCR	LHV 2 x LM6000 With SCR	LHV 2 x LMS100 With SCR
Direct Costs	109,552,000	193,841,000	106,870,000	189,976,000	92,757,000	168,473,000
Owner's Costs	12,552,000	21,824,000	12,129,000	21,274,000	10,329,000	18,655,000
Financing Costs During Construction	5,556,000	9,813,000	5,415,000	9,612,000	4,690,000	8,515,000
Working Capital and Inventories	2,191,000	3,877,000	2,137,000	3,800,000	1,855,000	3,369,000
Total	129,851,000	229,355,000	126,551,000	224,662,000	109,631,000	199,012,000
Net Degraded ICAP MW	87.56	188.72	87.57	188.75	87.06	187.59
$/kW	$1,483	$1,215	$1,445	$1,190	$1,259	$1,061

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	Albany 2 x LM6000 No SCR	Albany 2 x LMS100 No SCR	Albany 2 x GE 7FA No SCR	Syracuse 2 x LM6000 No SCR	Syracuse 2 x LMS100 No SCR	Syracuse 2 x GE 7FA No SCR
Direct Costs	77,497,000	146,187,000	170,437,000	76,615,000	144,665,000	168,694,000
Owner's Costs	8,651,000	16,205,000	18,873,000	8,553,000	16,039,000	18,683,000
Financing Costs During Construction	3,920,000	7,389,000	8,614,000	3,875,000	7,312,000	8,526,000
Working Capital and Inventories	1,550,000	2,924,000	3,409,000	1,532,000	2,893,000	3,374,000
Total	91,618,000	172,705,000	201,333,000	90,575,000	170,909,000	199,277,000
Net Degraded ICAP MW	86.69	186.74	300.30	86.19	185.61	298.72
$/kW	$1,057	$925	$670	$1,051	$921	$667

D. 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 A, 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 7.0, developed by the Electric Power Research Institute (EPRI) and data for existing plants reported on Federal Energy Regulatory Commission (FERC) Form 1. The resulting cost assumptions are summarized in Table II.7.

Table II 7. — Fixed O&M Assumptions (2007 $)

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	NYC and Long Island 2 x LM6000	NYC and Long Island 2 x LMS100	ROS 2 x LM6000	ROS 2 x LMS100	ROS 2 x GE 7FA
Average Labor Rate, incl. Benefits ($/hour)	$62.00	$62.00	$50.00	$50.00	$50.00
Operating Staff (full-time equivalents)	4.00	4.00	4.00	4.00	4.00
Maintenance Staff (full-time equivalents)	3.00	3.00	3.00	3.00	3.00
Routine Materials and Contract Services	$237,000	$305,000	$237,000	$305,000	$365,000
Administrative and General	$206,000	$206,000	$206,000	$206,000	$206,000

Other fixed operating costs are described below and summarized in Table II 8.

a. Site Leasing Costs

Site leasing costs are equal to the annual lease rate ($/acre-year) multiplied by the land requirement in acres. These values used were from the Levitan & Associates, Inc. (LAI) study, escalated by inflation.

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.

If the facility is a Qualified Empire Zone Enterprise, a property tax credit may apply, based on a formula that considers job creation, wages and benefits or investments made in the zone. For this analysis, it was assumed that most new combustion turbine facilities would not qualify for this credit.

Under the Industrial and Commercial Incentive Program (ICIP) in New York City, the project is granted a property tax exemption for the first 11 years, followed by a 20% decline in the exemption each year for four years, with full taxes due in the 16th year and thereafter.

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A New York State court has ruled that power plants in New York City qualify for the program as commercial improvement work. The continuous renewal of the ICIP in future years is assumed.

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

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

Table II.8.— Other Fixed Operating Cost Assumptions (2007 $)

	NYC	Long Island	ROS
Land Requirement (acres)[11]	3.50	3.50	3.50
Lease Rate ($/acre-year)	122,000	21,000	17,000
Property Tax Rate	12.01%	2.00%	4.00%
Assessment Ratio	45.00%	100.00%	50.00%
Effective Property Tax Rate	5.40% *	2.00%	2.00%
Insurance Rate	0.30%	0.30%	0.30%

* The effective rate excluding the ICIP property tax exemption granted during the first 15 years of operation.

2. 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 combustion inspections, periodic hot gas path inspections, and one major overhaul. For the aeroderivative units, GE recommends a major maintenance overhaul every 50,000 factored operating hours. For the frame units, major overhauls are every 48,000 operating hours or 2,400 factored starts, whichever occurs first. Normal operating hours and

[11] The individual unit equipment footprints are 56' x 14' for the LM6000; 130' x 20' for the LMS100; and 180' x 75' for the 7FA in simple cycle mode. A 3.5 acre site is adequate for siting of any of these technologies.

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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. The average variable O&M cost for major maintenance is thus 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. Other variable O&M costs are directly proportional to plant generating output, such as unscheduled maintenance, SCR catalyst and ammonia, water, and other chemicals and consumables. SCR is required in ozone non-attainment areas, which applies to all study locations except Albany and Syracuse. The GE 7EA cannot be equipped with an SCR because the hot-side gas temperature is too high. Variable O&M assumptions for each turbine model and location are summarized in Table II 9.

Table II.9. — Variable O&M Assumptions (2007 $)

	NYC, Long Island, & Lower Hudson Valley	**NYC, Long Island, & Lower Hudson Valley**	**ROS**	**ROS**	**ROS**
	2 x LM6000	**2 x LMS100**	**2 x LM6000**	**2 x LMS100**	**2 x GE 7EA**
Major Maintenance Interval (Operating Hours)	50,000	50,000	50,000	50,000	48,000
Major Maintenance Interval (Factored Starts)	N/A	N/A	N/A	N/A	2,400
Cost of Parts Required for Complete Major Maintenance Interval *	5,257,000	14,200,000	5,257,00 0	14,200,0 00	26,360,0 00
Man-Hours Required for Complete Major	2,496	6,700	2,496	6,700	17,760

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	NYC, Long Island, & Lower Hudson Valley	NYC, Long Island, & Lower Hudson Valley	ROS	ROS	ROS
	2 x LM6000	2 x LMS100	2 x LM6000	2 x LMS100	2 x GE 7EA
Maintenance Interval *					
Unscheduled Maintenance ($/MWh)	0.75	0.75	0.75	0.75	0.51
SCR Catalyst and Ammonia ($/MWh)	0.90	0.90	N/A	N/A	N/A
Water ($/MWh)	0.07	0.07	0.07	0.07	0.01
Other Chemicals and Consumables ($/MWh)	0.17	0.17	0.17	0.17	0.02

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

3. 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 prices 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 delivery point. The applicable local transportation rates include ConEd PSC No. 9-Gas (Leaf 277) for New York City and Keyspan PSC No. 1-Gas, Service Classification No. 14 (Leaf 189) for Long Island. In those two regions, the total delivered fuel price to an end user for interruptible service is the sum of the following:

- Texas Eastern Transmission Market Area 3 (TET-M3) Price
- System Cost Component

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— 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 50% capacity factor. According to discussions with representatives from ConEd and KeySpan, the Imbalance Charges are minimal in the day-ahead market. Those same representatives indicated that firm transportation service is not commonly provided because of the prohibitive costs of system reinforcement. Interruptible service gives ConEd and KeySpan 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 the rest of state were estimated from data for various existing plants in the Northeast. The estimated rates for each study region are summarized in Table II.10.

Table II.10. — Fuel Transportation Charges (2007 $)

	NYC	Long Island	ROS
Gas Transportation Service ($/mmBtu) *			
System Cost Component	0.100	0.100	—
Marginal Cost Component	0.092	0.140	—
Value Added Charge	0.005	0.005	—
Taxes	0.007	0.008	—
Pipeline Demand Charges ($/mmBtu)	—	—	0.400
Pipeline Commodity Charges ($/mmBtu)	—	—	0.002

* The minimum bill must be based on a capacity factor of 50%. For a peaking unit, the effective $/mmBtu cost is thus higher than the indicated rates.

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

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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 of the NERA report (not included in this document).

E. 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 and insurance were discussed in Section II.E.1.b. 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 7.50%, 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.11.

Table II.11. — Income Tax Assumptions

	NYC	Long Island and ROS
Federal Tax Rate	35.000%	35.000%
State Tax Rate	7.500%	7.500%
City Tax Rate	8.850%	0.000%
Composite Tax Rate *	45.628%	39.875%

* 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.

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2. Financing Assumptions

The financing of the plant is assumed to have a 50:50 ratio of debt to equity for a financially healthy merchant generator with a BBB credit rating. NERA has found this capital structure to be consistent with Standard & Poor's classification of merchant generation as "Business Position 8" under its ratings criteria with a mid-BBB rating target debt ratio of 47.5%[12]. NERA has estimated the cost of equity to be 12.0% based on the capital asset pricing model (CAPM) using a risk-free rate of 4.73%, an equity beta of 1.0, and an equity risk premium of 7.10% (4.73 + 1.0 x 7.10 = 11.83). The beta of 1.0 is consistent with observed equity betas for existing merchant generators. The equity risk premium is the Long Horizon Equity Risk Premium from 1926 to 2005 (Ibbotson Associates, *Stocks, Bonds, Bills and Inflation 2006 Yearbook*). The risk-free rate is the 20-year treasury yield and the estimated cost of debt is 7.00%, which is consistent with recent yields on corporate bonds rated Baa by Moody's (Source: http://www.federalreserve.gov /releases/h15/update/).

Financing assumptions for each region are summarized in Table II.12. 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 2.70% and are subsequently used to calculate the real weighted average cost of capital (WACC) and the real levelized carrying charge rates.

Table II.12. — Financing Assumptions

	NYC	Long Island and ROS
Equity Fraction	0.500	0.500
Debt Fraction	0.500	0.500
Cost of Equity (nominal)	12.00%	12.00%
Cost of Debt (nominal)	7.00%	7.00%
Cost of Equity (real)	9.06%	9.06%
Cost of Debt (real)	4.19%	4.19%

[12] Standard & Poors, "New Business Profile Scores Assigned for U.S. Utility and Power Companies; Financial Guidelines Revised," June 2, 2004.

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Weighted Average Cost of Capital *		
Before-Tax (nominal)	9.50%	9.50%
After-Tax (nominal)	7.90%	8.10%
Before-Tax (real)	6.62%	6.62%
After-Tax (real)	5.67%	5.79%
Tax Depreciation **	15-year MACRS	15-year MACRS
Inflation Rate	2.70%	2.70%

* (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) for a simple-cycle combustion turbine, adjusted for residual depreciation if the amortization period is less than 15 years.

While the LAI study used a constant 20-year amortization period across all regions, this study introduces a new methodology developed by NERA 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 profit function. This change in method 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 15-year MACRS depreciation in accordance with the federal tax code for a simple-cycle combustion turbine.

— **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.

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Annual carrying charge rates on a hypothetical $1,000,000 capital investment are derived in Appendix B, 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 II.13.

Table II.13.— 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 LAI study used the cost of equity as the discount rate on the principle that project-specific debt is already included in the revenue requirements. It states that the after-tax WACC would be used only if the debt components were removed from the revenue requirements. The LAI study also uses the cost of equity as a discount rate for the fixed O&M, property taxes, and insurance costs.

We believe, however, that the after-tax WACC is an appropriate discount rate for the entire annual revenue requirements, including all debt-related components. In theory, a discount rate should depend upon the riskiness of a future stream of payments. Greater risk in those payments would justify a risk premium that would raise the discount rate. Conversely, lower risk would justify a lower discount rate. The LAI study, however, effectively applies a higher discount rate (the cost of equity) to payment streams that have relatively lower risk (the debt components and the depreciation tax shield). This contradiction arises because revenue requirements, not cash

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flows, are being discounted. Leveraged cash flows are inherently riskier than unleveraged cash flows, but the same logic does not apply to revenue requirements.

The real levelized carrying charge rates as a function of amortization period are summarized in Table II.14. For additional clarity, the rates were derived both with and without property taxes and insurance, since these items are sometimes classified as part of the fixed O&M.

Table II.14. — Real Levelized Carrying Charge Rates

	NYC with ICIP	NYC without ICIP	LI and ROS
Levelized Carrying Charge Rates – with Property Taxes and Insurance:			
10-year amortization	17.16	22.56	18.57
15-year amortization	13.83	18.72	14.85
20-year amortization	12.61	16.74	12.95
25-year amortization	11.93	15.61	11.87
30-year amortization	11.50	14.90	11.20
35-year amortization	11.21	14.43	10.75
Levelized Carrying Charge Rates – Without Property Taxes and Insurance:			
10-year amortization	—	16.86	16.27
15-year amortization	—	13.02	12.55
20-year amortization	—	11.04	10.65
25-year amortization	—	9.91	9.57
30-year amortization	—	9.20	8.90
35-year amortization	—	8.73	8.45

The ICIP property tax abatement in New York City has a significant effect on the carrying charge rates. Over a 15.5-year amortization period, the ICIP reduces the levelized carrying charge rate by 35%. There are several reasons for a change of this magnitude:

— Under the ICIP, the normal property tax bill is not phased in until year 16, which is after the 15.5-year amortization period;

— Without the ICIP, the effective property tax rate for New York City is 5.40% compared to 2.00% elsewhere, as indicated in Section II.E.1.b;

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— Property taxes escalate with inflation due to valuation and/or rate adjustments. This is the assumption also used in the LAI report. Without the ICIP, the relatively high property taxes in New York City are constant in real terms through the entire amortization period. The LAI report does not indicate whether the ICIP was applied.

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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 B, Table B-2.

III. Estimating Energy Operating Profits

The next task is to estimate the annual profits of our hypothetical peaker. The profits are not to be based on any estimate of actual future supply and demand balances, however, but are required by the Tariff to be based on "conditions in which the available capacity would equal or slightly exceed the minimum Installed Capacity requirement.[13]

A. Overview of Approach

We have used historical data from 5/1/2003-12/31/2006 to benchmark the operation of the NYISO system. We then statistically estimate the effect of various cost drivers, including installed reserve margin, on the observed zonal LBMP values. This statistical model allows us to conceptually vary any causal variable to create an estimate of price under future conditions. At this point, we have an estimate of prices under the specified Tariff conditions.

We then use these prices to dispatch the hypothetical unit, calculating both day-ahead and real-time energy profits. In so doing we must create a hypothetical strategy for this unit and make decisions as to the degree of foresight the unit operator will have in choosing between commitment to the day-ahead market versus opportunistic behaviour in the real-time market. In addition, we must be mindful of real operating constraints on the unit with regards to start-up cost and start times. These calculations are carried out by zone.

[13] Seventh Revised Sheet 157

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We should note that we considered and rejected the other prominent competing method for estimating operating profits, namely production cost modelling. There are two prominent problems with this approach. The first is that production cost modelling does not mirror actual price experience. Production cost models by their very nature tend to understate actual electric prices, since they reflect a system which always behaves optimally and never has to adjust for unexpected contingencies in real time. These adjustments have real costs, and these costs are often substantial. The second problem is that for practical purposes, production cost models must be run at expected conditions and cannot be run as a system actually runs, *i.e.* with widely varying gas prices, weather and demand conditions and transient transmission irregularities. The effect of these things are not linear, particularly under peak conditions and thus do not average out.

Thus, our approach assumes that the best evidence on what electric prices will be is what electric prices have been, adjusted where possible for known changes.

B. Data

The hourly day-ahead and five-minute zonal LBMPs are publicly available at the NYISO website, as are zonal loads. These were augmented by daily gas prices taken from Bloomberg (Texas Eastern Transmission M3 Price) which were then linearly interpolated across non-trading days. Temperatures were taken from data supplied by NOAA. Long Island and New York temperatures were taken from JFK airport. Upstate temperatures were taken at Albany Airport. The final addition was a series of excess purchases of capacity, by month, supplied by the NYISO in three capacity zones, New York City, Long Island, and the Rest of State. These began in May 2003. Gas transportation costs were taken from Table A-2.

The use of the period from May 2003 to December 2006 was chosen to sample over a wide range of conditions in input prices, cost drivers (*e.g.* weather) while staying reasonably close to the present structure of the market. In particular, this period covers the time of the implementation of scarcity pricing in the NYISO which sharply increases prices on occasion.

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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 units change, and from other transient factors, *e.g.* temperature. If, as a first approximation, we regard the supply curve is fixed, then varying demand traces out the supply curve. Thus, our estimation strategy is to use load to identify the supply curve while varying the supply curve from hour-to-hour to reflect underlying technical supply differentials. The remainder of unmeasured effects, which are substantial, are left as residuals in the underlying model. Thus,

$LBMP_{hz}$ = f(NY Load, Zonal Load, Attributes of Hour h, Attributes of Zone z, Gas Price, Reserve Margin, Temperature) + ε

The complete specification is given in the Appendix. The standard indicia of model fit are quite good. The basic regression model explains about 83 percent of the underlying variation in electric prices. This implies that given the zone, the hour, the NY and zonal load, Gas Price, reserve margin and temperature, we can capture about 83 percent of the variation in electricity price around its mean. The remaining 17 percent of the variation that is unexplained are 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.

With one exception, all causal factors work as expected. Thus, for example, price increases as load increases, and increases faster the more load increases[14]. Prices are generally higher on the weekends and in the shoulder months (Adjusting for load differences) to reflect outage patterns on deferrable maintenance. Higher temperatures cause higher prices, even adjusting for load, due to degraded performance of units. Finally, prices fall as reserve margins rise, with one exception: for reasons that are not entirely clear, prices on Long Island do not seem to be negatively related to reserve margin. Indeed, the only effect discernible is a small positive effect, which contradicts the expected economic

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

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relationship. Consequently, we have assumed that price on Long Island is essentially unrelated to observed reserve margin and we use estimated profits over the last 3½ years to estimate annual day-ahead profits.

D. Price Prediction

The Tariff requires conditions at or slightly above target margins. In the period observed margins were usually substantially in excess of the target margin. Thus, to estimate what prices would have been at the required Tariff conditions, we can recalculate prices using the statistical equation to calculate the change in prices attributable to a shrinking (or growth) of the observed reserve margin holding all other factors constant. We should note in particular that holding all other factors constant necessitates holding the unmeasured factors constant as well. Thus, we do not set the error terms (which reflect the unmeasured factors) to their average level of zero, but allow them to take whatever value they actually took in the data.

In essence, then, we choose as a base the actual conditions prevailing over the sample period, adjusting only for reserve margin. The use of this historic period is in many ways preferable to forecast the future. First, the last three-and-one-half years are broadly representative of patterns which are expected in the future in any case. We have periods of relatively low demand and relatively high demand as well as hot and cool summers. In any case, there is no particular reason to expect net price formation to follow any different path.

Gas prices average around $8/MMBTU over the study period, which is reasonably close to currently observed forward prices for natural gas over the forecast period, although current quotes are slightly higher. This does not matter very much for the calculation of peaker profits, however, since higher levels of gas prices tend to translate into roughly unchanged levels of profits for a peaking unit, since both revenues and costs rise in approximately the same amount[15].

We have examined other adjustments to make to the supply curve as well. For example, the methodology would allow us to adjust for transmission additions to Long Island from the 660 MW Neptune project. In the limit, we could regard this project as essentially reducing load by 660 MW

[15] Note that this is a statement about the average gas price levels. In extreme conditions, for a variety of reasons, prices are higher than a direct gas price comparison might suggest. This effect has been included in the modeling.

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year-round on Long Island. Again, owing to the odd distribution of prices on Long Island, we see very little effect on peaking prices on Long Island from the Neptune cable.

E. Hypothetical Dispatch

We have assumed that the unit is bid into the day-ahead market at a price which reflects the observed daily gas price and observed variable O&M. If taken, the unit runs in those hours and earns an operating profit equal to the difference between price and cost. We separately count starts and reduce profits by a start-up gas cost. In practice, units are virtually never taken more than once per day.

In the hours in which the unit is not dispatched in the day-ahead market, it considers operation in the real time market. We have examined real time operation under several different alternatives, all of which yield similar results.

We have taken the five-minute real time zonal prices and carry out the following algorithm. First, we calculate operating profits for each unit in each zone if it ran at that price, using daily gas prices just as in the day-ahead calculations. We group these five-minute operating profits into continuous hours of operation and treat these as homogeneous units.

We next adjust for start-up time. If the unit was operating day-ahead in the previous hour, we allow it to continue running without an incremental start if the operating profit from the real-time price is positive, and allow it to continue running as long as the real-time profit is positive. If however, the unit was not running in the first hour of positive profits, we again allow it to continue running for contiguous blocks of profitable operation, but subtract start-up fuel costs and reduce the expected profit in the first hour by 50 percent in NYC and Long Island to reflect a 30 minute start-up time and by 1/6 upstate to reflect a ten minute start time. If the total value of the contiguous block is positive, we book those hourly profits. We have tried numerous different strategies for dispatch in the real time market and all yield similar results. The approach used here has two major simplifications. First, we assume sufficient foresight to predict a profitable block of hours as soon as a profitable opportunity arises which would seem to require a start-up. Second, we assume that all runtimes are measured (including start-up time). Third, we assume that the pattern of prices over the hour is such that given hourly profit is evenly divisible over the hour.

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We should note that we have not adjusted real time profits for reserve margin. The logic behind that decision is fairly simple. First, we know that real-time prices will always follow day-ahead prices. The absence of arbitrage opportunities in a competitive market requires that the expected value of the real-time market be no higher than the day-ahead market. Thus, the possibility of a profitable opportunity should be about the same regardless of the level of prices within a reasonable range. Against this, we might expect some additional opportunities for very high price as the supply demand balance tightens. On the other hand, since the number of hours the unit already runs rises as the day-ahead prices rise, the opportunity to take advantage of a higher number of scarcity hours falls. Consequently, we have made no adjustment.

F. Results

Table 2 summarizes the results. Presented are the unit type and region, the margin above or below the capacity requirement, and aggregate profits, which can be broken down into real time profits and net day-ahead profits, where start-up costs are netted out of gross profits.

G. Other Considerations: Adjustments to NYC Prices

Several market participants have argued that the addition of 1,000 MW of new combined cycle capacity in 2006 should be expected to lower energy prices in 2007 and forward by more than would be implied by the additions this capacity adds to the reserve margin. While this effect makes sense as a potential matter, the quantitative effect will depend on the particular units displaced by these units and the shape of the Demand Curve in that region. Thus, theoretically, there is no real reason for the addition of capacity which is inframarginal to affect prices for peakers at all, beyond their obvious effect on shifting the supply curve out, which effect is already captured in the reserve margin adjustment. So long as there are enough peakers in NY which are marginal, an addition of baseload capacity will simply move the clearing price down the supply curve to peakers with roughly the same costs.

In fact, when we look at 2006, while it is true that the regression somewhat over predicts New York City in 2006, as is consistent with the possibility that the new capacity reduced prices, the over prediction is also consistent with normal levels of variance around expected prices. Thus, it is impossible to conclude on a valid statistical basis that there was any effect at all. The total impact on

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prices in New York City in any case would be under 75 cents pet MWh, with most of that change concentrated in mid-merit hours in which it is less likely that peakers will be operating.

Several market participants have raised the issue that the larger size of the LMS100 vis-à-vis the LM6000 makes it more likely that it will collapse prices in NYC load pockets if such a plant is built in a load pocket, and that these load pockets substantially contribute to the high level of prices in NYC. Thus, to simulate this effect, we have assumed that an LMS100, if built, will be connected at a 345kV bus and earn these rates rather than the average NYC zonal rate. Using Poletti as a 345kV connection (as does the market monitoring report) we find that prices in the 345kV system are, on average $1.54/MWh lower than the NYC zonal price, so we have adjusted LM100 dispatch to reflect this lower rate. Note that this does not mean that an LMS100 would necessarily be constructed to directly inter-tie with the 345kV system, only that wherever it chooses to locate, such prices would be likely to follow.

Variables in the Regression Model

Dependent Variable:

lbmp	Zonal LBMP in $/MWh

Independent Variables:

_cons	Indicator variable =1
dow	Indicator variable for day of week, 1=Monday, etc.
nameind	Indicator variable for zone, 1=Capital, 2=Central, 3=Dunwood, 4=Genesee, 5=Hudson Valley, 6= Long Island, 7=Mohawk Valley, 8=Millwood, 9=NYC, 10=North, 11=West
tmin	Daily minimum temperature in degrees Fahrenheit
tmax	Daily maximum temperature in degrees Fahrenheit
tmean	Daily mean temperature in degrees Fahrenheit
load	Hourly zonal load for the hour in MW
aggload	Aggregate hourly NYISO load in MW
aggload2	$aggload^2$ divided by 10^8
aggload3	$aggload^3$ divided by 10^{12}
region	Indicator variable for region, 1=Rest of State, 2=NYC, 3=Long Island
h	Indicator variable for hour: 1=Midnight-1 am, 2=1 am-2am, etc.
m	Indicator variable for month: 1= January, etc.
lgasp	Natural logarithm of gasp price plus gas transportation cost in log $/MMBTU
rm	Supplied reserves divided by required reserves, measured monthly

IV. Developing the Demand Curves and Calculating Carrying Charges

A. Approach Overview

The Demand Curve Model is designed to find the annual CONE at the reference point that will provide for the full recovery of capital costs over a twenty year amortization period, using the financial assumptions of a 50/50 capital structure and 7/12 debt/equity cost. The CONE consists of two items. First, 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 and a tendency in the long term to earn energy revenues consistent with a degree of excess capacity. The second is an energy offset based on energy revenues over the three year period assuming capacity levels at one-half of one percent above the target capacity level.

The model allows for a wide array of scenarios by incorporating about forty variables that can be changed to accommodate different market conditions, target levels of capacity and Demand Curve shapes (intercept and kink). In addition, various regions (e.g., New York City, Capital) and three types of generator units (LMS100, LM6000 or Frame 7) can be simulated. This flexibility allows the user to compare the effect of a variable over multiple scenarios.

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 these values. A lower zero crossing point (i.e., closer to 100%) produces a shorter amortization period and higher carrying charge as demand revenues go down faster for a given level of excess capacity.

Many of the inputs to the Demand Curve model requirements are based on judgment. The inputs used will be described below. As a result of the judgmental nature of the inputs, it is important to note that in selecting inputs, we are guided also by the result produced. The results produced show implied amortization periods of 14.5-18.5 years in ROS and NYC, with ROS somewhat lower due to the lower zero crossing point.

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B. Model Description

The model works by simulating revenues and expenditures given a set of input parameters, energy functions, the region and the 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 a demand payments that satisfy the zero supernormal profit criteria (revenues equal expenditures). Supernormal profits are those above the normal cost of equity capital.

A new generating unit can expect to receive revenues from two main sources. Energy and ancillary service profits represent long-term power contracts or sales on the spot energy and ancillary service markets. These are modeled using a Monte Carlo analysis. The model uses the user-defined expected value and standard deviation of supply to generate 100 possible values for capacity. These are put through an energy and ancillary service profit function. The function is region and unit-specific and calculates expected energy and ancillary services profit 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 and to adjust the Demand Curve so that given an expectation of surplus capacity, the new entrant will be able to fully recover costs.

Demand payments approximate payments the owner of a new unit could expect to make through NYISO ICAP 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.

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.

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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 the model for the Demand Curve, it calculates profits 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.

C. Model Inputs

The model's thirty plus variables can be broken down into the following categories:

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

As previously described, we see no compelling reason to change the existing zero crossing point and use 112% for ROS and 118% for NYC and LI.

Technological progress variables can be used to determine how the cost of new entry increases or decreases over time.

The DOE forecasts roughly a 0.5% real decline in capital costs. We have used a .25% decline to recognize that non-technology factors could offset this decline.

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

Residual Value is the value of the unit at the end of the thirty year life. For aeroderivatives, we use a residual value of 5% of the initial investment

Monte Carlo variables are used to calculate expected values for demand payments and energy and ancillary service payments.

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Based on modeling work filed by PJM, we use a 1.4% standard deviation in the capacity level achieved relative to need. Considering the NYISO's Reliability Need Assessment (RNA) process and procedures to prevent inadequate capacity levels, we assume that the typical achieved level of capacity will be two standard deviations above the required level. This applies to both the energy and capacity function. This allows for a 5% probability of a capacity shortage in the spot capacity market.

As New York City and Long Island are smaller markets, they could be expected to have larger capacity variability. The standard deviation for those areas are set at 2.0%.

Restructuring Risks – the Demand Curve is an administered value subject to regulatory risk. We assume 20 percent probability that the Demand Curve will yield only 50% of the required revenue.

Energy function variables can be used to change the shape of the energy function and can also be used to change the way energy and ancillary service profits in the first three years are calculated.

The energy profit functions are described in Section III. In developing the recommendation, we use an energy and ancillary service profit offset at 100.5% of the target installed capacity level. Essentially we assume energy profits at this level for the first three years.

Property taxes for NYC may be used with or without the Industrial and Commercial Incentive Program (ICIP). The effect is very significant. The ICIP will expire June 30, 2007 if not renewed. We assume that the ICIP will be renewed. This fact will be known before the Demand Curve becomes effective.

D. Analysis of Results

The implied amortization period for ROS is 14.5 years. The implied carrying charge is 14.99% and the premium on WACC[16] is 229 basis points. For the NYC LMS-100, the implied amortization period is 14.5 years, the implied carrying charge is 13.71% and the implied premium on WACC is 132 basis

[16] Implied WACC premiums are quoted in this section relative to a 20 year amortization period and 50/50 and 7/12 capital structure.

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points (for the LM-6000, the implied amortization period is 13.5 years, the implied carrying charge is 14.40% and the implied WACC premium is 207 basis points).

Results for Long Island are somewhat different. For the LMS-100, the implied amortization period is 22.5 years, the implied carrying charge is 12.36 percent and the implied equity premium is -52 basis points. In the LM-6000, the values are 18.5 years, 13.36% and 55 basis points. The Long Island results show less risk as a much higher portion of returns come from energy markets which are much less sensitive to capacity surpluses for the LMS-100 and LM-6000.

As discussed above, the model inputs require judgment. Hence, we believe that it is important to apply a reasonableness assessment to the results. In general, the results indicate that the using an investment grade capital structure the amortization period is under 15 years for ROS and NYC and at a 20 year amortization period, the WACC premium is roughly 200 basis points.

These results appear to reasonably reflect a degree of merchant risk and to represent a considerable move in that direction from the prior update[17]. Using ROS as an example, a 30 year life would yield a carrying charge of 11.20% the 2004 update used 20 years which, all else equal, would yield a charge rate of 12.95%. The current study uses 14.99%.

For reference, the ROS carrying charge at 10 years is 18.57%. The function begins to flatten at 15 years, but is sharply sloped prior to that point, much like a mortgage. While some may agree that merchant risk should have an even greater impact on the amortization period and carrying charge that we allow, there are several factors that mitigate against this. First, there is the desire to maintain continuity. We are already moving to reflect considerably more merchant risk than the previous update. Second, risk should be reduced as adjoining markets (PJM and ISO NE) institute forward markets and the NYISO is not flooded with imported capacity. Third, higher merchant risk levels, such as those associated with 10 year amortization, would probably be unsustainable in equilibrium. Such spot price levels would make contracting a much more attractive alternative. We see little value in developing a Demand Curve that is not reasonably sustainable.

[17] We do not mean to imply that merchant risk was not reflected in the prior study. The 2004 update used a 20 year amortization period. For reference, carrying charges for ROS are 18.57% at 10 years, 14.85% at 15 years, 12.95% at 20 years and 11.2% at 30 years.

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E. Demand Curve Recommendations

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V. Sensitivity Analyses

Numerous sensitivity analyses were conducted using the Demand Curve and carrying charge model in order to identify variables that would have a significant impact on results. Further, the model is available to the public to conduct sensitivities. Two related variables dominate the assumption sensitivities. Those variables are the standard deviation of capacity relative to the installed capacity level and the average installed capacity level relative to the target or required level. Relatively small changes in those variables have a significant impact on results. For all other variables, impacts are moderate.

For example, the ROS demand at the reference point is $90.00/kW year using a 1.4% standard deviation and 102.8% average capacity level and the amortization period is 14.5 years. If we use the same standard deviation and an average capacity level of 104.2% the price rises to $101.40 and the amortization period changes to 12.5 years. If we use a 101.4% average capacity level, the price drops to $80.90 and the amortization period increases to 17.5 years. Ideally, we would have an empirical basis for this assumption, but there is not sufficient history to develop one. Arguments could be made ranging from 101.4 to 104.2. While we believe that we have selected variables for these values that both are plausible and consistent with the RNA process and that produce results that introduce a reasonable but not excessive degree of merchant risk, we do not claim that they are the only plausible values for these variables. We are guided in the selection of these variables by the results that they produce. We then use the Demand Curve Model to produce results that are consistent with and responsive to other assumptions – for example, the Demand Curve zero crossing point and technical progress assumption.

We have sensitivity tested all key assumptions. We provide here examples for ROS. Moving the ROS zero crossing point to 115% from 112% would decrease the reference value by $3.80/kW year. Increasing the technical progress rate to 0.5% would increase this reference point by $2.30/kW year, reducing the 20% regulatory risk probability to zero would reduce the reference point by $6.80/kW year, reflecting a five percent residual value would reduce the reference point by $3.30 per kW year and basing the energy and ancillary service profit for the Demand Curve period on a capacity level of

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104.2 of the target would increase price by $1.10/kW year. In sum, most input variables or assumptions have a moderate impact. The primary exception is the average capacity level.

The model also shows that a major change to the Demand Curve shape would have a significant impact. For example a kinked Demand Curve with an initial slope forward a 133 percent crossing point and kink at 106% to 112% would reduce the reference point by $19.20/kW year. This would, of course, not necessarily reduce the cost of capacity to load by the amount as the curve would be flatter between 100% and 106%. This case does illustrate how the model can be used to evaluate such large changes to the Demand Curve shape.

As we have provided the model to the market participants to enable them to conduct their own sensitivities, we do not summarize all the sensitivities we have viewed herein.

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VI. Appendices

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

Appendix A provides more detailed information about the cost and performance characteristics of the peaking technologies evaluated in this study.

Table A-1 and Figures A-1 through A-6 provide information on the capacity and heat rates for the LMS100, 7FA, and LM6000PC Sprint as a function of elevation, temperature, and humidity.

Table A-2 provides capacity and heat rate information by technology and by location in tabular form. It also shows data for outage rates, availability, start 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 provides capital cost estimates for each technology by location. Cost breakdown is provided for both EPC and non-EPC costs.

Table A-6 provides a comparison of LM6000 and 7FA cost estimates for this study with the published cost estimates of the previous Demand Curve review in 2004.

Tables A-7 through A-10 provide an in-depth comparison of four line items from the LM6000 cost estimates in Table A-5 for New York City and upstate (Zone C). The purpose of this comparison is to show how differences in material costs, labor productivity and labor rates were used to estimate the higher cost of construction in New York City. The four line items are equipment, construction labor and materials, electrical connection and substation, and site preparation. The crew wage rates shown in Table A-7 and A-8 include the base craft rate; fringe benefits; FICA and federal and state unemployment insurance; workmen's compensation costs; construction equipment, including fuel, oil and maintenance; markup for small tools and expendables; and markup for site overheads, including construction trailers, indirect craft support, and craft supervision.

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

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

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Figure A-1 — LMS100: Net kW vs. Ambient Temperature

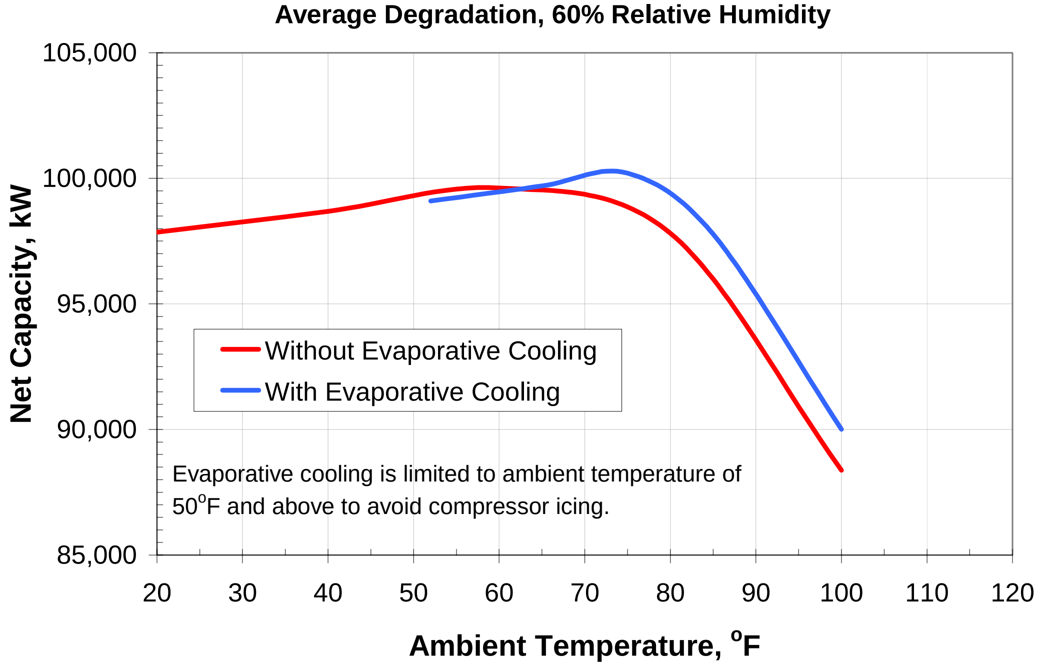

Figure A-2 — LMS100: Net Capacity vs. Net Heat Rate

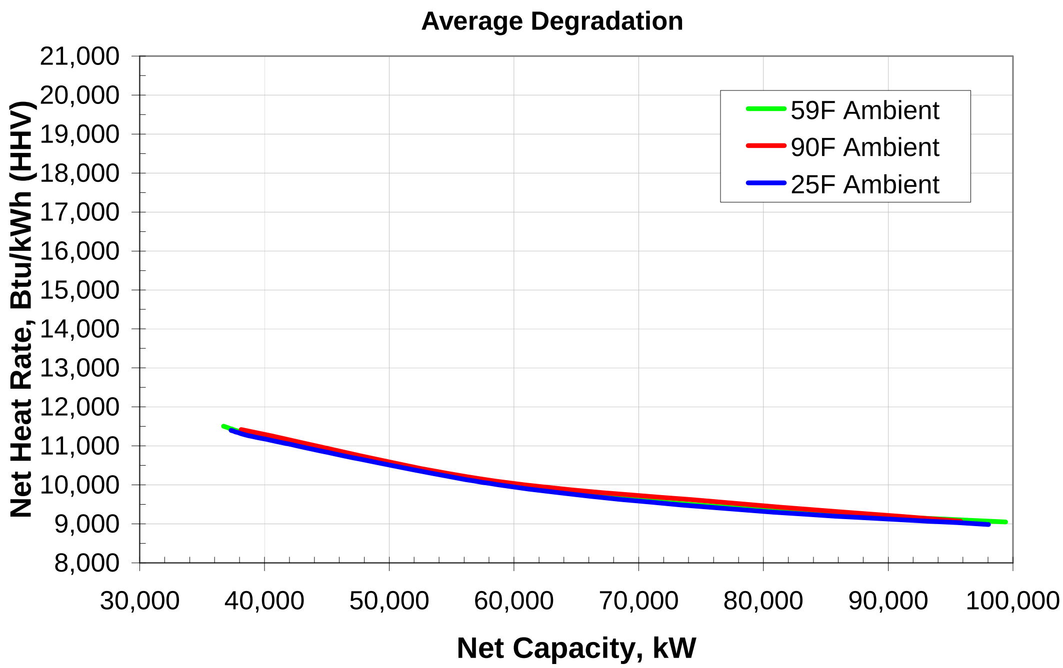

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Figure A-3 — 7FA: Net kW vs. Ambient Temperature

Average Degradation, 60% Relative Humidity

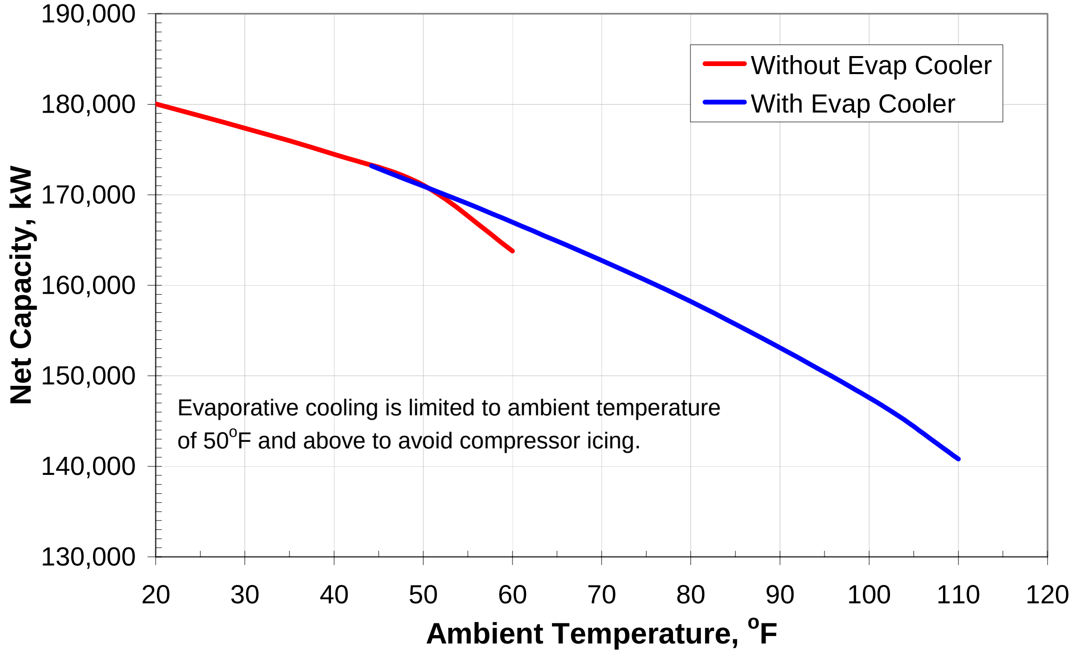

Figure A-4 — 7FA: Net Capacity vs. Net Heat Rate

Average Degradation

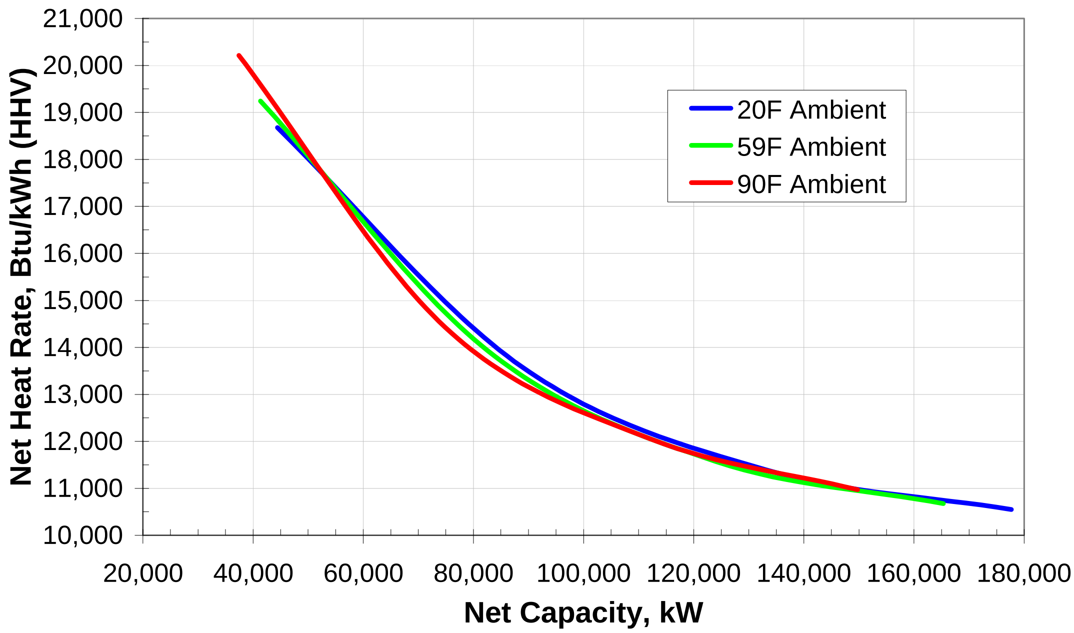

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Figure A-5 — LM6000PC – Sprint: Net kW vs. Ambient Temperature

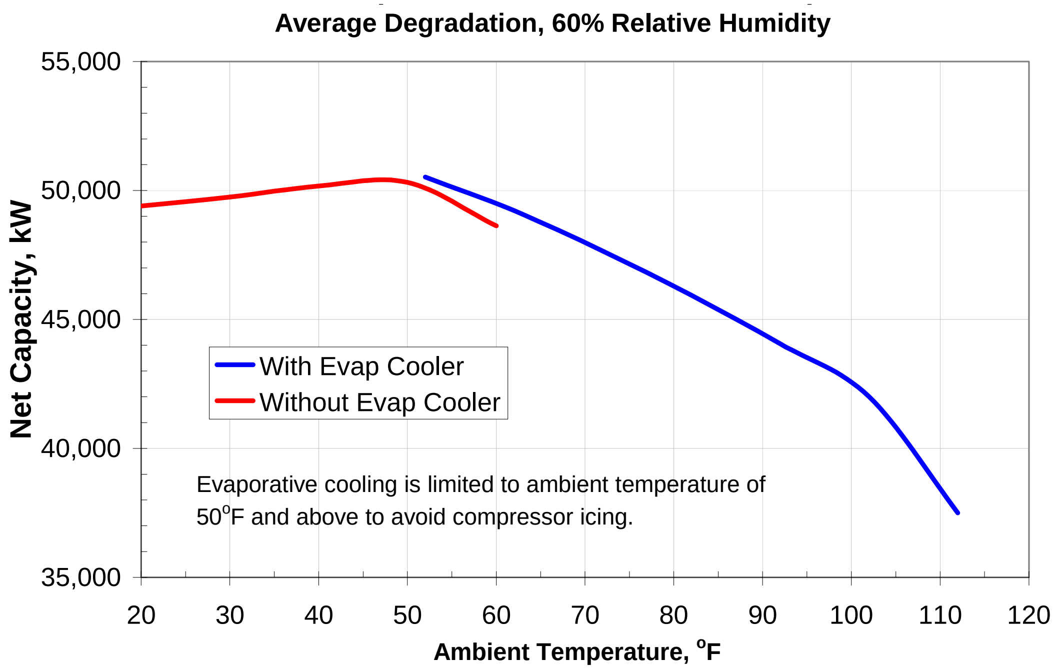

Figure A-6 — LM6000PC – Sprint: Net Capacity vs. Net Heat Rate

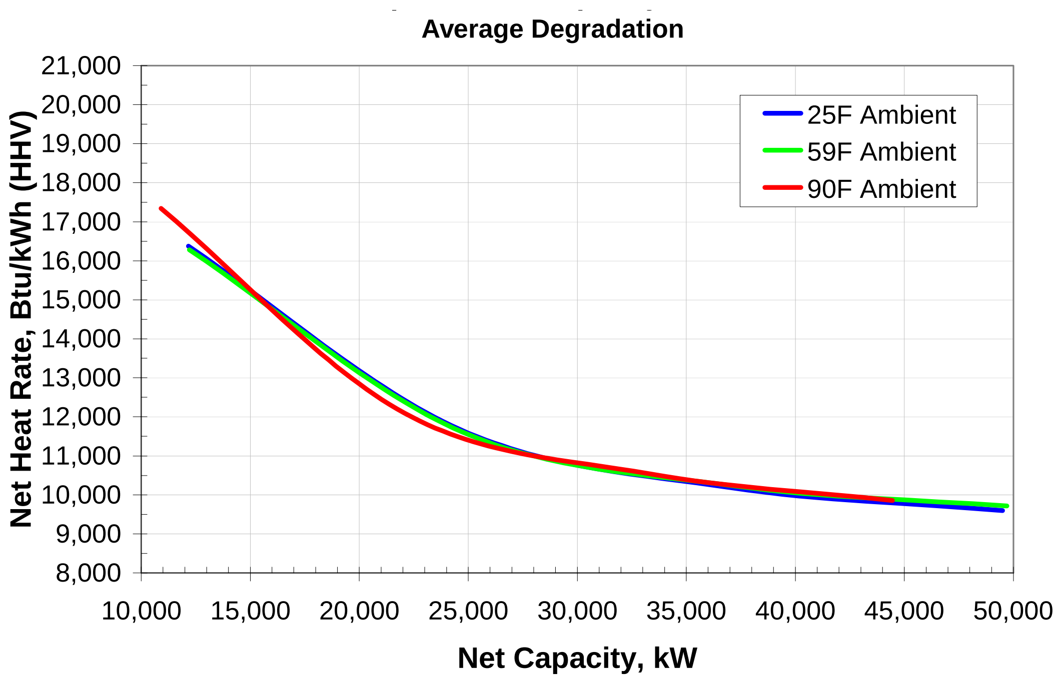

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Table A-2 — Operating Cost and Performance Summary

	Long Island	NYC	Hudson Valley	Albany	Syracuse	Long Island	NYC	Hudson Valley	Albany	Syracuse	Albany	Syracuse	Comments
Combustion Turbine Model	LM6000	LM6000	LM6000	LM6000	LM6000	LMS100	LMS100	LMS100	LMS100	LMS100	GE 7FA	GE 7FA	
Plant Performance (per Unit)													
Net Plant Capacity - Summer (MW)	45.671	45.497	44.688	45.318	45.216	98.307	97.954	96.115	97.518	97.278	155.446	155.045	Avg. degraded value; with evaporative cooling.
Net Plant Capacity - Winter (MW)	49.697	49.698	49.429	49.203	48.954	98.222	98.221	98.148	98.264	98.541	179.309	177.825	Avg. degraded value; evaporative cooler off.
Net Plant Capacity - Summer/Winter Avg. (MW)	47.684	47.598	47.059	47.261	47.085	98.265	98.088	97.132	97.891	97.910	167.378	166.435	Avg. degraded value.
Net Plant Capacity - ICAP (MW)	43.785	43.778	43.529	43.347	43.095	94.376	94.360	93.795	93.370	92.806	150.148	149.361	Avg. degraded value; with evaporative cooling.
Net Plant Heat Rate - Summer (MW)	9,814	9,818	9,835	9,811	9,808	9,151	9,159	9,191	9,147	9,140	10,860	10,852	Avg. degraded value; with evaporative cooling.
Net Plant Heat Rate - Winter (MW)	9,624	9,624	9,565	9,547	9,555	8,993	8,993	8,957	8,946	8,937	10,548	10,550	Avg. degraded value; evaporative cooler off.
Net Plant Heat Rate - Summer/Winter Avg. (MW)	9,719	9,721	9,700	9,679	9,682	9,072	9,076	9,074	9,047	9,039	10,704	10,701	Avg. degraded value.
Net Plant Heat Rate - ICAP (MW)	9,878	9,878	9,879	9,880	9,880	9,248	9,248	9,250	9,251	9,252	10,971	10,971	Avg. degraded value; with evaporative cooling.
Equivalent Forced Outage Rate - Demand Based ($EFOR_d$)	3.68%	3.68%	3.68%	3.68%	3.68%	3.68%	3.68%	3.68%	3.68%	3.68%	3.68%	3.68%	Long-term average.

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	Long Island	NYC	Hudson Valley	Albany	Syracuse	Long Island	NYC	Hudson Valley	Albany	Syracuse	Albany	Syracuse	Comments
Combustion Turbine Model	LM6000	LM6000	LM6000	LM6000	LM6000	LMS100	LMS100	LMS100	LMS100	LMS100	GE 7FA	GE 7FA	
Equivalent Availability Factor	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	Long-term average.
Natural Gas Consumed During Start (mmBtu/start)	110.00	110.00	110.00	65.00	65.00	215.00	215.00	215.00	135.00	135.00	360.00	360.00	
Fixed O&M (2 Units, $/year)													
Labor - Routine O&M	902,720	902,720	728,000	728,000	728,000	902,720	902,720	728,000	728,000	728,000	728,000	728,000	
Materials and Contract Services - Routine	237,000	237,000	237,000	237,000	237,000	305,000	305,000	305,000	305,000	305,000	365,000	365,000	
Administrative and General	206,000	206,000	206,000	206,000	206,000	206,000	206,000	206,000	206,000	206,000	206,000	206,000	
Subtotal Fixed O&M	1,345,720	1,345,720	1,171,000	1,171,000	1,171,000	1,413,720	1,413,720	1,239,000	1,239,000	1,239,000	1,299,000	1,299,000	
$/kW-year	15.37	15.37	13.45	13.51	13.59	7.49	7.49	6.60	6.63	6.68	4.33	4.35	Based on net degraded ICAP capacity.
Other Fixed Costs (2 Units, $/year)													
Site Leasing Costs	73,500	427,000	59,500	59,500	59,500	73,500	427,000	59,500	59,500	59,500	59,500	59,500	
Subtotal Fixed O&M	1,419,220	1,772,720	1,230,500	1,230,500	1,230,500	1,487,220	1,840,720	1,298,500	1,298,500	1,298,500	1,358,500	1,358,500	
$/kW-year	16.21	20.25	14.13	14.19	14.28	7.88	9.75	6.92	6.95	7.00	4.52	4.55	Based on net degraded ICAP capacity.

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	Long Island	NYC	Hudson Valley	Albany	Syracuse	Long Island	NYC	Hudson Valley	Albany	Syracuse	Albany	Syracuse	Comments
Combustion Turbine Model	LM6000	LM6000	LM6000	LM6000	LM6000	LMS100	LMS100	LMS100	LMS100	LMS100	GE 7FA	GE 7FA	
Property Taxes	2,531,020	7,016,044	2,192,620	1,832,360	1,811,500	4,493,240	12,392,395	3,980,240	3,454,100	3,418,180	4,026,660	3,985,540	Full amount, not accounting for the NYC phased property tax exemption with the ICIP.
Insurance	379,653	389,553	328,893	274,854	271,725	673,986	688,065	597,036	518,115	512,727	603,999	597,831	
Total Fixed O&M (2 Units)	4,329,893	9,178,317	3,752,013	3,337,714	3,313,725	6,654,446	14,921,180	5,875,776	5,270,715	5,229,407	5,989,159	5,941,871	Alternatively, property taxes and insurance may be included in the fixed charge rate, which would account for the phasing of the NYC property tax exemption with the ICIP.
$/kW-year	49.44	104.83	43.10	38.50	38.45	35.25	79.07	31.32	28.22	28.17	19.94	19.89	Based on net degraded ICAP capacity.
Variable O&M ($/MWh)													
Major Maintenance Parts	2.20	2.21	2.23	2.22	2.23	2.89	2.90	2.92	2.90	2.90	3.28	3.30	
Major Maintenance Labor	0.06	0.07	0.05	0.05	0.05	0.08	0.08	0.07	0.07	0.07	0.11	0.11	
Unscheduled Maintenance	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.51	0.51	
SCR Catalyst and Ammonia	0.90	0.90	0.90	0.00	0.00	0.90	0.90	0.90	0.00	0.00	0.00	0.00	
Other Chemicals and Consumables	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.02	0.02	
Water	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.01	0.01	
Total Variable O&M ($/MWh)	4.16	4.16	4.18	3.27	3.28	4.86	4.87	4.88	3.96	3.96	3.93	3.95	Based on net degraded summer/winter avg. capacity.

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	Long Island	NYC	Hudson Valley	Albany	Syracuse	Long Island	NYC	Hudson Valley	Albany	Syracuse	Albany	Syracuse	Comments
Combustion Turbine Model	LM6000	LM6000	LM6000	LM6000	LM6000	LMS100	LMS100	LMS100	LMS100	LMS100	GE 7FA	GE 7FA	
<u>Variable O&M - Cost per Start:</u>													Excluding natural gas consumed (shown above).
Major Maintenance Parts	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	10,983	10,983	This cost is already included in $/MWh above.
Major Maintenance Labor	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	370	370	This cost is already included in $/MWh above.
Total ($/factored start)	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	11,353	11,353	Factored starts include weighting factors for trips.

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Table A-3 — Capital Cost Estimates for LMS100 - Demand Curve Review

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	Overnight Capital Cost - 2007$s					Costs as a % of Zone C			
	K - Long Island	J - NYC	G - Hudson Valley	F - Capital	C - Central	K - Long Island	J - NYC	G - Hudson Valley	F - Capital
EPC Cost Components									
Equipment									
Equipment	85,040,000	85,040,000	85,040,000	77,149,000	77,149,000	110%	110%	110%	100%
Spare Parts	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	100%	100%	100%	100%
Subtotal	86,040,000	86,040,000	86,040,000	78,149,000	78,149,000	110%	110%	110%	100%
Construction									
Construction Labor & Materials	64,518,000	66,857,000	47,689,000	37,399,000	36,213,000	178%	185%	132%	103%
Electrical Connection & Substation	3,564,000	3,793,000	2,825,000	2,531,000	2,470,000	144%	154%	114%	102%
Electrical System Upgrades	500,000	500,000	500,000	500,000	500,000	100%	100%	100%	100%
Gas Interconnect & Reinforcement	4,250,000	5,000,000	4,250,000	4,250,000	4,250,000	100%	118%	100%	100%
Site Prep	2,428,000	2,491,000	1,841,000	1,498,000	1,460,000	166%	171%	126%	103%
Engineering & Design	8,420,000	8,562,000	7,437,000	6,418,000	6,349,000	133%	135%	117%	101%
Construction Mgmt. / Field Engr.	2,105,000	2,140,000	1,859,000	1,605,000	1,587,000	133%	135%	117%	101%
Subtotal	85,785,000	89,343,000	66,401,000	54,201,000	52,829,000	162%	169%	126%	103%
Startup & Testing									
Startup & Training	1,403,000	1,427,000	1,239,000	1,070,000	1,058,000	133%	135%	117%	101%
Testing	-	-	-	-	-	N/A	N/A	N/A	N/A
Subtotal	1,403,000	1,427,000	1,239,000	1,070,000	1,058,000	133%	135%	117%	101%
Contingency	16,748,000	17,031,000	14,793,000	12,767,000	12,629,000	133%	135%	117%	101%
Subtotal - EPC Costs	189,976,000	193,841,000	168,473,000	146,187,000	144,665,000	131%	134%	116%	101%
Non-EPC Cost Components									
Owner's Costs									
Permitting	1,900,000	1,938,000	1,685,000	1,462,000	1,447,000	131%	134%	116%	101%
Legal	3,800,000	3,877,000	3,369,000	2,924,000	2,893,000	131%	134%	116%	101%
Owner's Project Mgmt. & Misc. Engr.	3,800,000	3,877,000	3,369,000	2,924,000	2,893,000	131%	134%	116%	101%
Social Justice	375,000	500,000	125,000	125,000	125,000	300%	400%	100%	100%
Owner's Development Costs	5,699,000	5,815,000	5,054,000	4,386,000	4,340,000	131%	134%	116%	101%
Financing Fees	3,800,000	3,877,000	3,369,000	2,924,000	2,893,000	131%	134%	116%	101%
Financial Advisory	475,000	485,000	421,000	365,000	362,000	131%	134%	116%	101%
Environmental Studies	475,000	485,000	421,000	365,000	362,000	131%	134%	116%	101%
Market Studies	475,000	485,000	421,000	365,000	362,000	131%	134%	116%	101%
Interconnection Studies	475,000	485,000	421,000	365,000	362,000	131%	134%	116%	101%
Subtotal	21,274,000	21,824,000	18,655,000	16,205,000	16,039,000	133%	136%	116%	101%
Financing (incl. AFUDC, IDC)									
EPC Portion	8,644,000	8,820,000	7,666,000	6,652,000	6,582,000	131%	134%	116%	101%
Non-EPC Portion	968,000	993,000	849,000	737,000	730,000	133%	136%	116%	101%
Working Capital and Inventories	3,800,000	3,877,000	3,369,000	2,924,000	2,893,000	131%	134%	116%	101%
Subtotal - Non-EPC Costs	34,686,000	35,514,000	30,539,000	26,518,000	26,244,000	132%	135%	116%	101%
Total Capital Investment	224,662,000	229,355,000	199,012,000	172,705,000	170,909,000	131%	134%	116%	101%

Table A-4 — Capital Cost Estimates for GE 7FA - Demand Curve Review

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	Overnight Capital Cost - 2007$s		Costs as a % of Zone C
	F - Capital	C - Central	F - Capital
EPC Cost Components			
Equipment			
Equipment	86,661,000	86,652,000	100%
Spare Parts	1,000,000	1,000,000	100%
Subtotal	87,661,000	87,652,000	100%
Construction			
Construction Labor & Materials	47,454,000	46,036,000	103%
Electrical Connection & Substation	2,470,000	2,470,000	100%
Electrical System Upgrades	500,000	500,000	100%
Gas Interconnect & Reinforcement	5,000,000	5,000,000	100%
Site Prep	1,835,000	1,790,000	103%
Engineering & Design	7,492,000	7,413,000	101%
Construction Mgmt. / Field Engr.	1,873,000	1,853,000	101%
Subtotal	66,624,000	65,062,000	102%
Startup & Testing			
Startup & Training	1,249,000	1,235,000	101%
Testing	-	-	N/A
Subtotal	1,249,000	1,235,000	101%
Contingency	14,903,000	14,745,000	101%
Subtotal - EPC Costs	170,437,000	168,694,000	101%
Non-EPC Cost Components			
Owner's Costs			
Permitting	1,704,000	1,687,000	101%
Legal	3,409,000	3,374,000	101%
Owner's Project Mgmt. & Misc. Engr.	3,409,000	3,374,000	101%
Social Justice	125,000	125,000	100%
Owner's Development Costs	5,113,000	5,061,000	101%
Financing Fees	3,409,000	3,374,000	101%
Financial Advisory	426,000	422,000	101%
Environmental Studies	426,000	422,000	101%
Market Studies	426,000	422,000	101%
Interconnection Studies	426,000	422,000	101%
Subtotal	18,873,000	18,683,000	101%
Financing (incl. AFUDC, IDC)			
EPC Portion	7,755,000	7,676,000	101%
Non-EPC Portion	859,000	850,000	101%
Working Capital and Inventories	3,409,000	3,374,000	101%
Subtotal - Non-EPC Costs	30,896,000	30,583,000	101%
Total Capital Investment	201,333,000	199,277,000	101%

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Table A-5 — Capital Cost Estimates for LM6000 - Demand Curve Review

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	Overnight Capital Cost - 2007$s					Costs as a % of Zone C			
	K - Long Island	J - NYC	G - Hudson Valley	F - Capital	C - Central	K - Long Island	J - NYC	G - Hudson Valley	F - Capital
EPC Cost Components									
Equipment									
Equipment	41,502,000	41,502,000	41,502,000	36,072,000	36,072,000	115%	115%	115%	100%
Spare Parts	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000	100%	100%	100%	100%
Subtotal	42,502,000	42,502,000	42,502,000	37,072,000	37,072,000	115%	115%	115%	100%
Construction									
Construction Labor & Materials	39,786,000	41,279,000	28,954,000	21,997,000	21,335,000	186%	193%	136%	103%
Electrical Connection & Substation	3,323,000	3,549,000	2,602,000	2,316,000	2,257,000	147%	157%	115%	103%
Electrical System Upgrades	500,000	500,000	500,000	500,000	500,000	100%	100%	100%	100%
Gas Interconnect & Reinforcement	3,400,000	4,000,000	3,400,000	3,400,000	3,400,000	100%	118%	100%	100%
Site Prep	1,487,000	1,526,000	1,124,000	912,000	888,000	167%	172%	127%	103%
Engineering & Design	4,660,000	4,755,000	4,015,000	3,318,000	3,278,000	142%	145%	122%	101%
Construction Mgmt. / Field Engr.	1,165,000	1,189,000	1,004,000	829,000	819,000	142%	145%	123%	101%
Subtotal	54,321,000	56,798,000	41,599,000	33,272,000	32,477,000	167%	175%	128%	102%
Startup & Testing									
Startup & Training	777,000	793,000	669,000	553,000	546,000	142%	145%	123%	101%
Testing	-	-	-	-	-	N/A	N/A	N/A	N/A
Subtotal	777,000	793,000	669,000	553,000	546,000	142%	145%	123%	101%
Contingency	9,270,000	9,459,000	7,987,000	6,600,000	6,520,000	142%	145%	123%	101%
Subtotal - EPC Costs	106,870,000	109,552,000	92,757,000	77,497,000	76,615,000	139%	143%	121%	101%
Non-EPC Cost Components									
Owner's Costs									
Permitting	1,069,000	1,096,000	928,000	775,000	766,000	140%	143%	121%	101%
Legal	2,137,000	2,191,000	1,855,000	1,550,000	1,532,000	139%	143%	121%	101%
Owner's Project Mgmt. & Misc. Engr.	2,137,000	2,191,000	1,855,000	1,550,000	1,532,000	139%	143%	121%	101%
Social Justice	375,000	500,000	125,000	125,000	125,000	300%	400%	100%	100%
Owner's Development Costs	3,206,000	3,287,000	2,783,000	2,325,000	2,298,000	140%	143%	121%	101%
Financing Fees	2,137,000	2,191,000	1,855,000	1,550,000	1,532,000	139%	143%	121%	101%
Financial Advisory	267,000	274,000	232,000	194,000	192,000	139%	143%	121%	101%
Environmental Studies	267,000	274,000	232,000	194,000	192,000	139%	143%	121%	101%
Market Studies	267,000	274,000	232,000	194,000	192,000	139%	143%	121%	101%
Interconnection Studies	267,000	274,000	232,000	194,000	192,000	139%	143%	121%	101%
Subtotal	12,129,000	12,552,000	10,329,000	8,651,000	8,553,000	142%	147%	121%	101%
Financing (incl. AFUDC, IDC)									
EPC Portion	4,863,000	4,985,000	4,220,000	3,526,000	3,486,000	140%	143%	121%	101%
Non-EPC Portion	552,000	571,000	470,000	394,000	389,000	142%	147%	121%	101%
Working Capital and Inventories	2,137,000	2,191,000	1,855,000	1,550,000	1,532,000	139%	143%	121%	101%
Subtotal - Non-EPC Costs	19,681,000	20,299,000	16,874,000	14,121,000	13,960,000	141%	145%	121%	101%
Total Capital Investment	126,551,000	129,851,000	109,631,000	91,618,000	90,575,000	140%	143%	121%	101%

Table A-6 — Comparison of Capital Cost Estimates - Demand Curve Review

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	Capital Cost Comparison 2 x LM6000 New York City				Capital Cost Comparison 2 x LM6000 ROS (Syracuse)				Capital Cost Comparison 2 x 7FA ROS (Syracuse)			
	This DC Review		Last DC Review[1]		This DC Review		Last DC Review[1]		This DC Review		Last DC Review[1,3]	
	Cost (2007$)	Non-EPC as % of EPC	Cost (2004$)	Non-EPC as % of EPC	Cost (2007$)	Non-EPC as % of EPC	Cost (2004$)	Non-EPC as % of EPC	Cost (2007$)	Non-EPC as % of EPC	Cost (2004$)	Non-EPC as % of EPC
EPC Cost Components												
Equipment												
Equipment	41,502,000		40,500,000		36,072,000		40,500,000		86,652,000		115,857,000	
Spare Parts	1,000,000		1,000,000		1,000,000		1,000,000		1,000,000		3,482,000	
Subtotal	42,502,000		41,500,000		37,072,000		41,500,000		87,652,000		119,339,000	
Construction												
Construction Labor & Materials	41,279,000		44,980,000		21,335,000		33,960,000		46,036,000		112,544,000	
Electrical Connection & Substation	3,549,000		3,500,000		2,257,000		2,750,000		2,470,000		6,821,000	
Electrical System Upgrades	500,000		2,500,000		500,000		1,250,000		500,000		5,000,000	
Gas Interconnect & Reinforcement	4,000,000		4,000,000		3,400,000		3,400,000		5,000,000		6,500,000	
Site Prep	1,526,000		2,200,000		888,000		1,300,000		1,790,000		2,828,000	
Engineering & Design	4,755,000		4,000,000		3,278,000		3,000,000		7,413,000		7,125,000	
Construction Mgmt. / Field Engr.	1,189,000		0		819,000		0		1,853,000		0	
Subtotal	56,798,000		61,180,000		32,477,000		45,660,000		65,062,000		140,818,000	
Startup & Testing												
Startup & Training	793,000		750,000		546,000		750,000		1,235,000		1,895,000	
Testing	-		250,000		-		250,000		-		707,000	
Subtotal	793,000		1,000,000		546,000		1,000,000		1,235,000		2,602,000	
Contingency	9,459,000		0		6,520,000		0		14,745,000		0	
Subtotal - EPC Costs	109,552,000		103,680,000	100%	76,615,000		88,160,000	100%	168,694,000		262,759,000	100%
Non-EPC Cost Components												
Owner's Costs												
Permitting	1,096,000	1.00%	4,050,000	3.91%	766,000	1.00%	1,050,000	1.19%	1,687,000	1.00%	1,697,000	0.65%
Legal	2,191,000	2.00%	1,285,714	1.24%	1,532,000	2.00%	1,000,000	1.13%	3,374,000	2.00%	1,414,000	0.54%
Owner's Project Mgmt. & Misc. Engr.	2,191,000	2.00%	1,333,333	1.29%	1,532,000	2.00%	1,000,000	1.13%	3,374,000	2.00%	2,239,000	0.85%
Social Justice	500,000	0.46%	500,000	0.48%	125,000	0.16%	125,000	0.14%	125,000	0.07%	400,000	0.15%
Owner's Development Costs	3,287,000	3.00%	0	0.00%	2,298,000	3.00%	0	0.00%	5,061,000	3.00%	0	0.00%
Financing Fees	2,191,000	2.00%	0	0.00%	1,532,000	2.00%	0	0.00%	3,374,000	2.00%	0	0.00%
Financial Advisory	274,000	0.25%	0	0.00%	192,000	0.25%	0	0.00%	422,000	0.25%	0	0.00%
Environmental Studies	274,000	0.25%	0	0.00%	192,000	0.25%	0	0.00%	422,000	0.25%	0	0.00%
Market Studies	274,000	0.25%	0	0.00%	192,000	0.25%	0	0.00%	422,000	0.25%	0	0.00%
Interconnection Studies	274,000	0.25%	0	0.00%	192,000	0.25%	0	0.00%	422,000	0.25%	0	0.00%
Subtotal	12,552,000	11.46%	7,169,047	6.91%	8,553,000	11.16%	3,175,000	3.60%	18,683,000	11.08%	5,750,000	2.19%
Financing (incl. AFUDC, IDC) [2]												
EPC Portion	4,985,000	4.55%	3,169,895	3.06%	3,486,000	4.55%	1,899,500	2.15%	7,676,000	4.55%	10,190,000	3.88%
Non-EPC Portion	571,000	0.52%	0	0.00%	389,000	0.51%	0	0.00%	850,000	0.50%	0	0.00%
Working Capital and Inventories	2,191,000	2.00%	0	0.00%	1,532,000	2.00%	0	0.00%	3,374,000	2.00%	0	0.00%
Subtotal - Non-EPC Costs	20,299,000	18.53%	10,338,942	9.97%	13,960,000	18.22%	5,074,500	5.76%	30,583,000	18.13%	15,940,000	6.07%
Total Capital Investment	129,851,000	118.53%	114,018,942	109.97%	90,575,000	118.22%	93,234,500	105.76%	199,277,000	118.13%	278,699,000	106.07%

Notes:

1. Levitan & Associates, Independent Study to Establish Parameters of the ICAP Demand Curves for the New York Independent System Operator, August 16, 2004, p. 6.
2. Value for this review is estimated from a typical construction period drawdown schedule for a gas turbine peaking plant.
3. Excludes $1,000,000 in Emission Reduction Credits.

March 22, 2007 ICAP Working Group Meeting

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Table A-7 — Breakdown of Selected Costs for LM6000 Installation in Zone J (New York City) (costs in 2007 $)

Description	Total Equipment Cost	Total Material Cost	Total Personnel Hours	Crew Wage Rate	Total Construction & Erection Cost	Total Projected Cost
Combustion Turbines w/ Accessories	29,100,000		15,180	126.44	1,919,359	31,019,359
SCR w/ Exhaust Stack	5,500,000		22,080	126.44	2,791,795	8,291,795
Pumps	330,400		1,866	127.57	238,015	568,415
Field Erected Tanks	350,000					350,000
Shop Fabricated Tanks	272,000		1,230	126.46	155,494	427,494
Cranes & Hoists	10,000		69	127.57	8,802	18,802
Fuel Gas Compressors	1,340,000		2,346	126.44	296,628	1,636,628
Fuel Gas Conditioning	370,000		607	126.44	76,774	446,774
Bulk Gas Storage Provisions		8,000	193	126.44	24,428	32,428
Air Compressors & Dryers	114,000		331	126.44	41,877	155,877
Fire Protection	350,000					350,000
B.O.P. Mechanical (Miscellaneous)	92,500		552	126.44	69,795	162,295
BOP Piping		599,830	27,283	129.62	3,536,439	4,136,269
Valves & Specialties	174,500		806	132.57	106,841	281,341
Electrical Major Equipment	2,015,000		6,127	117.89	722,364	2,737,364
Electrical BOP		1,142,950	41,327	121.93	5,038,908	6,181,858
Instrumentation & Controls	945,000		3,809	127.19	484,441	1,429,441
Steel		113,394	1,214	144.70	175,718	289,112
Buildings		542,000	8,432	126.44	1,066,117	1,608,117
Foundations		525,599	17,565	120.56	2,117,653	2,643,253
Heavy Haul Subcontracts					325,000	325,000
Construction and Temporary Utilities					100,000	100,000
Indirect and Startup Craft Support			2,600	126.44	328,744	328,744
Allowances to Attract Labor			17,235		5,139,441	5,139,441
Erection Contractors G&A and Profit					4,547,304	4,547,304
Consumables					227,900	227,900
Freight, Duties, Taxes, Etc.	538,353	207,951				746,304
EPC Contractor's Fee					8,599,000	8,599,000
Total Equipment, Materials, & Labor	41,501,753	3,139,724	170,852		38,138,839	82,780,316
Switchyard	1,258,700		17,946	127.61	2,290,028	3,548,728
Site Preparation, Drainage, & Yard Work		430,660	8,402	130.33	1,094,999	1,525,659

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Table A-8 — Breakdown of Selected Costs for LM6000 Installation in Zone C (Syracuse) (costs in 2007 $)

Description	Total Equipment Cost	Total Material Cost	Total Personnel Hours	Crew Wage Rate	Total Construction & Erection Cost	Total Projected Cost
Combustion Turbines w/ Accessories	29,100,000		11,550	72.92	842,226	29,942,226
SCR w/ Exhaust Stack	5,500,000		16,800	72.92	1,225,056	6,725,056
Pumps	330,400		1,420	73.61	104,497	434,897
Field Erected Tanks	350,000					350,000
Shop Fabricated Tanks	272,000		936	73.12	68,411	340,411
Cranes & Hoists	10,000		53	73.61	3,865	13,865
Fuel Gas Compressors	1,340,000		1,785	72.92	130,162	1,470,162
Fuel Gas Conditioning	370,000		462	72.92	33,689	403,689
Bulk Gas Storage Provisions		8,000	147	72.92	10,719	18,719
Air Compressors & Dryers	114,000		252	72.92	18,376	132,376
Fire Protection	350,000					350,000
B.O.P. Mechanical (Miscellaneous)	92,500		420	72.92	30,626	123,126
BOP Piping		599,830	20,759	78.56	1,630,694	2,230,524
Valves & Specialties	174,500		613	81.15	49,761	224,261
Electrical Major Equipment	2,015,000		4,662	64.51	300,760	2,315,760
Electrical BOP		1,139,752	31,445	68.36	2,149,521	3,289,273
Instrumentation & Controls	945,000		2,898	68.17	197,557	1,142,557
Steel		104,187	924	87.63	80,972	185,159
Buildings		542,000	6,416	72.92	467,818	1,009,818
Foundations		484,179	13,365	68.12	910,404	1,394,583
Heavy Haul Subcontracts					325,000	325,000
Construction and Temporary Utilities					100,000	100,000
Indirect and Startup Craft Support			2,600	72.92	189,592	189,592
Allowances to Attract Labor			13,163		2,681,851	2,681,851
Erection Contractors G&A and Profit					2,730,018	2,730,018
Consumables					227,700	227,700
Freight, Duties, Taxes, Etc.	538,353	205,529				743,882
EPC Contractor's Fee					6,759,000	6,759,000
Total Equipment, Materials, and Labor	41,501,753	3,083,477	130,668		21,268,275	65,853,505
Switchyard	1,258,700		13,654	73.10	998,122	2,256,822
Site Preparation, Drainage, & Yard Work		430,660	6,393	79.74	509,757	940,417

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Table A-9 — Difference in Selected Costs for LM6000 Installation in Zones J and C
(Zone J minus Zone C)
(costs in 2007 $)

Description	Total Equipment Cost	Total Material Cost	Total Personnel Hours	Crew Wage Rate	Total Construction & Erection Cost	Total Projected Cost
Combustion Turbines w/ Accessories	0		3,630	53.52	1,077,133	1,077,133
SCR w/ Exhaust Stack	0		5,280	53.52	1,566,739	1,566,739
Pumps	0		446	53.96	133,518	133,518
Field Erected Tanks	0					0
Shop Fabricated Tanks	0		294	53.34	87,084	87,084
Cranes & Hoists	0		17	53.96	4,938	4,938
Fuel Gas Compressors	0		561	53.52	166,466	166,466
Fuel Gas Conditioning	0		145	53.52	43,085	43,085
Bulk Gas Storage Provisions		0	46	53.52	13,709	13,709
Air Compressors & Dryers	0		79	53.52	23,501	23,501
Fire Protection	0					0
B.O.P. Mechanical (Miscellaneous)	0		132	53.52	39,168	39,168
BOP Piping		0	6,524	51.07	1,905,745	1,905,745
Valves & Specialties	0		193	51.42	57,080	57,080
Electrical Major Equipment	0		1,465	53.38	421,604	421,604
Electrical BOP		3,198	9,883	53.57	2,889,387	2,892,585
Instrumentation & Controls	0		911	59.02	286,885	286,885
Steel		9,207	290	57.06	94,746	103,953
Buildings		0	2,016	53.52	598,299	598,299
Foundations		41,420	4,200	52.44	1,207,250	1,248,670
Heavy Haul Subcontracts					0	0
Construction and Temporary Utilities					0	0
Indirect and Startup Craft Support			0	53.52	139,152	139,152
Allowances to Attract Labor			4,072		2,457,590	2,457,590
Erection Contractors G&A and Profit					1,817,286	1,817,286
Consumables					227,900	200
Freight, Duties, Taxes, Etc.	0	2,422				2,422
EPC Contractor's Fee					1,840,000	1,840,000
Total Equipment, Materials, and Labor	0	56,247	40,185		16,870,564	16,926,812
Switchyard	0		4,291	54.51	1,291,906	1,291,906
Site Preparation, Drainage, & Yard Work		0	2,009	50.59	585,242	585,242

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Table A-10 — Percentage Difference in Selected Costs for LM6000 Installation in Zones J and C (Zone J minus Zone C)

Description	Total Equipment Cost	Total Material Cost	Total Personnel Hours	Crew Wage Rate	Total Construction & Erection Cost	Total Projected Cost
Combustion Turbines w/ Accessories	0%		31%	73%	128%	3.6%
SCR w/ Exhaust Stack	0%		31%	73%	128%	23%
Pumps	0%		31%	73%	128%	31%
Field Erected Tanks	0%					0%
Shop Fabricated Tanks	0%		31%	73%	127%	26%
Cranes & Hoists	0%		31%	73%	128%	36%
Fuel Gas Compressors	0%		31%	73%	128%	11%
Fuel Gas Conditioning	0%		31%	73%	128%	11%
Bulk Gas Storage Provisions		0%	31%	73%	128%	73%
Air Compressors & Dryers	0%		31%	73%	128%	18%
Fire Protection	0%					0%
B.O.P. Mechanical (Miscellaneous)	0%		31%	73%	128%	32%
BOP Piping		0%	31%	65%	117%	85%
Valves & Specialties	0%		31%	63%	115%	25%
Electrical Major Equipment	0%		31%	83%	140%	18%
Electrical BOP		0.3%	31%	78%	134%	88%
Instrumentation & Controls	0%		31%	87%	145%	25%
Steel		8.8%	31%	65%	117%	56%
Buildings		0%	31%	73%	128%	59%
Foundations		8.6%	31%	77%	133%	90%
Heavy Haul Subcontracts					0%	0%
Construction and Temporary Utilities					0%	0%
Indirect and Startup Craft Support			0%	73%	73%	73%
Allowances to Attract Labor			31%		92%	92%
Erection Contractors G&A and Profit					67%	67%
Consumables					100%	0.1%
Freight, Duties, Taxes, Etc.	0%	1.2%				0.3%
EPC Contractor's Fee					27%	27%
Total Equipment, Materials, and Labor	0%	1.8%	31%		79%	26%
Switchyard	0%		31%	75%	129%	57%
Site Preparation, Drainage, & Yard Work		0%	31%	63%	115%	62%

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B. Appendix 2 – Financial Assumptions

Table B-1 — Real Carrying Charges on Capital Investment

Merchant Generator Example

Calendar Year		2008	2009	2010	2011	2012	2013	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	15	16	17	18	19	20
Effective Income Tax Rate	39.875%	39.875%	39.875%	39.875%	39.875%	39.875%	39.875%	39.875%	39.875%	39.875%	39.875%	39.875%	39.875%	39.875%	39.875%	39.875%	39.875%	39.875%	39.875%	39.875%	39.875%
Total Project Capitalized Cost		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%	5.910%	2.950%	0.000%	0.000%	0.000%	0.000%
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	88,600	29,500	0	0	0	0
Financing																					
DEBT SERVICE:		500,000																			
Loan Balance Start of Year		500,000	483,532	466,375	448,499	429,875	410,472	390,255	369,193	347,248	324,385	300,564	275,746	249,889	222,949	194,881	165,638	135,171	103,428	70,356	35,899
Principal		16,468	17,157	17,876	18,624	19,404	20,216	21,063	21,945	22,863	23,821	24,818	25,857	26,940	28,068	29,243	30,467	31,743	33,072	34,457	35,899
Interest		20,935	20,245	19,527	18,778	17,999	17,186	16,340	15,458	14,539	13,582	12,584	11,545	10,463	9,335	8,160	6,935	5,660	4,330	2,946	1,503
Balance at End of Year		483,532	466,375	448,499	429,875	410,472	390,255	369,193	347,248	324,385	300,564	275,746	249,889	222,949	194,881	165,638	135,171	103,428	70,356	35,899	0
EQUITY:		500,000																			
TOTAL FINANCING		1,000,000																			
Income Statement (Check)																					
Carrying Charge Revenues:		129,623	100,237	107,013	113,147	118,771	123,952	126,702	127,287	127,830	128,531	129,126	129,882	130,533	131,348	132,061	152,504	172,914	173,795	174,714	175,671
Capital Related Expenses:																					
Property Taxes		20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000
Insurance		3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000
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	59,100	29,500	0	0	0	0
Interest Expenses		20,935	20,245	19,527	18,778	17,999	17,186	16,340	15,458	14,539	13,582	12,584	11,545	10,463	9,335	8,160	6,935	5,660	4,330	2,946	1,503
Taxable Income		35,689	-38,009	-21,013	-5,631	8,472	21,466	28,362	29,829	31,191	32,949	34,442	36,336	37,971	40,013	41,801	93,068	144,254	146,465	148,768	151,167
Income Taxes		14,231	-15,156	-8,379	-2,246	3,378	8,559	11,309	11,894	12,437	13,138	13,734	14,489	15,141	15,955	16,668	37,111	57,521	58,403	59,321	60,278
Principal		16,468	17,157	17,876	18,624	19,404	20,216	21,063	21,945	22,863	23,821	24,818	25,857	26,940	28,068	29,243	30,467	31,743	33,072	34,457	35,899
Cash Flow to Equit Equity IRR = **9.06%**	-500,000	54,990	54,990	54,990	54,990	54,990	54,990	54,990	54,990	54,990	54,990	54,990	54,990	54,990	54,990	54,990	54,990	54,990	54,990	54,990	54,990
Derivation of Carrying Charges																					
Target Equity IRR = 9.06%																					
Principal	-	16,468	17,157	17,876	18,624	19,404	20,216	21,063	21,945	22,863	23,821	24,818	25,857	26,940	28,068	29,243	30,467	31,743	33,072	34,457	35,899
Interest Expenses	-	20,935	20,245	19,527	18,778	17,999	17,186	16,340	15,458	14,539	13,582	12,584	11,545	10,463	9,335	8,160	6,935	5,660	4,330	2,946	1,503
Target Cash Flow to Equity	-	54,990	54,990	54,990	54,990	54,990	54,990	54,990	54,990	54,990	54,990	54,990	54,990	54,990	54,990	54,990	54,990	54,990	54,990	54,990	54,990
Income Taxes	-	14,231	-15,156	-8,379	-2,246	3,378	8,559	11,309	11,894	12,437	13,138	13,734	14,489	15,141	15,955	16,668	37,111	57,521	58,403	59,321	60,278
Property Taxes and Insurance		23,000	23,000	23,000	23,000	23,000	23,000	23,000	23,000	23,000	23,000	23,000	23,000	23,000	23,000	23,000	23,000	23,000	23,000	23,000	23,000
Total Carrying Charges	-	129,623	100,237	107,013	113,147	118,771	123,952	126,702	127,287	127,830	128,531	129,126	129,882	130,533	131,348	132,061	152,504	172,914	173,795	174,714	175,671
Annual Rate (% of initial capital investment)		12.96%	10.02%	10.70%	11.31%	11.88%	12.40%	12.67%	12.73%	12.78%	12.85%	12.91%	12.99%	13.05%	13.13%	13.21%	15.25%	17.29%	17.38%	17.47%	17.57%
After-Tax Cost of Capital = 5.79%																					
Present Value Factor		0.9453	0.8936	0.8447	0.7985	0.7548	0.7135	0.6745	0.6376	0.6027	0.5698	0.5386	0.5091	0.4813	0.4550	0.4301	0.4066	0.3843	0.3633	0.3434	0.3246
Present Value		122,533	89,571	90,396	90,349	89,652	88,445	85,462	81,160	77,048	73,233	69,548	66,128	62,825	59,759	56,797	62,001	66,454	63,139	60,001	57,029
Cumulative Present Value		122,533	212,104	302,500	392,848	482,500	570,945	656,407	737,567	814,615	887,849	957,396	1,023,525	1,086,349	1,146,108	1,202,905	1,264,906	1,331,360	1,394,499	1,454,499	1,511,528
Levelized Carrying Charges (Real)	129,507																				
Levelized Carrying Charge Rate (Real) =	$\boxed{12.95\%}$																				

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

Amortization Years =	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35
Base Case:																										
With Property Taxes and Insurance:																										
non-NYC:	18.57%	17.57%	16.73%	16.01%	15.39%	14.85%	14.37%	13.95%	13.57%	13.24%	12.95%	12.69%	12.45%	12.24%	12.05%	11.87%	11.71%	11.57%	11.43%	11.31%	11.20%	11.10%	11.00%	10.91%	10.83%	10.75%
NYC:	17.16%	16.13%	15.34%	14.71%	14.22%	13.83%	13.52%	13.25%	13.01%	12.80%	12.61%	12.45%	12.30%	12.16%	12.04%	11.93%	11.83%	11.73%	11.65%	11.57%	11.50%	11.43%	11.37%	11.31%	11.26%	11.21%
NYC w/o ICIP:	22.56%	21.53%	20.67%	19.93%	19.29%	18.72%	18.22%	17.78%	17.39%	17.05%	16.74%	16.46%	16.22%	15.99%	15.79%	15.61%	15.44%	15.29%	15.15%	15.02%	14.90%	14.79%	14.69%	14.60%	14.51%	14.43%
Without Property Taxes and Insurance:																										
non-NYC:	16.27%	15.27%	14.43%	13.71%	13.09%	12.55%	12.07%	11.65%	11.27%	10.94%	10.65%	10.39%	10.15%	9.94%	9.75%	9.57%	9.41%	9.27%	9.13%	9.01%	8.90%	8.80%	8.70%	8.61%	8.53%	8.45%
NYC:	16.86%	15.83%	14.97%	14.23%	13.59%	13.02%	12.52%	12.08%	11.69%	11.35%	11.04%	10.76%	10.52%	10.29%	10.09%	9.91%	9.74%	9.59%	9.45%	9.32%	9.20%	9.09%	8.99%	8.90%	8.81%	8.73%
200 bp higher on nominal debt and equity cost:																										
With Property Taxes and Insurance:																										
non-NYC:	20.37%	19.36%	18.51%	17.79%	17.16%	16.61%	16.13%	15.71%	15.34%	15.01%	14.72%	14.46%	14.23%	14.03%	13.84%	13.67%	13.52%	13.38%	13.25%	13.14%	13.03%	12.94%	12.85%	12.76%	12.69%	12.62%
NYC:	19.09%	18.05%	17.23%	16.58%	16.07%	15.65%	15.32%	15.03%	14.77%	14.54%	14.34%	14.16%	14.00%	13.86%	13.73%	13.61%	13.50%	13.40%	13.32%	13.23%	13.16%	13.09%	13.03%	12.97%	12.92%	12.87%
NYC w/o ICIP:	24.49%	23.45%	22.57%	21.82%	21.17%	20.60%	20.09%	19.64%	19.25%	18.91%	18.60%	18.33%	18.08%	17.87%	17.67%	17.49%	17.33%	17.18%	17.05%	16.92%	16.81%	16.71%	16.61%	16.53%	16.44%	16.37%
Without Property Taxes and Insurance:																										
non-NYC:	18.07%	17.06%	16.21%	15.49%	14.86%	14.31%	13.83%	13.41%	13.04%	12.71%	12.42%	12.16%	11.93%	11.73%	11.54%	11.37%	11.22%	11.08%	10.95%	10.84%	10.73%	10.64%	10.55%	10.46%	10.39%	10.32%
NYC:	18.79%	17.75%	16.87%	16.12%	15.47%	14.90%	14.39%	13.94%	13.55%	13.21%	12.90%	12.63%	12.38%	12.17%	11.97%	11.79%	11.63%	11.48%	11.35%	11.22%	11.11%	11.01%	10.91%	10.83%	10.74%	10.67%
400 bp higher on nominal debt and equity cost:																										
With Property Taxes and Insurance:																										
non-NYC:	22.22%	21.20%	20.35%	19.63%	19.00%	18.46%	17.98%	17.56%	17.20%	16.88%	16.59%	16.34%	16.12%	15.93%	15.75%	15.59%	15.45%	15.32%	15.20%	15.10%	15.00%	14.91%	14.83%	14.76%	14.69%	14.63%
NYC:	21.07%	20.02%	19.19%	18.53%	17.99%	17.56%	17.21%	16.90%	16.63%	16.39%	16.18%	16.00%	15.83%	15.68%	15.55%	15.43%	15.33%	15.23%	15.14%	15.06%	14.99%	14.92%	14.86%	14.80%	14.75%	14.70%
NYC w/o ICIP:	26.47%	25.42%	24.53%	23.78%	23.12%	22.55%	22.04%	21.60%	21.21%	20.87%	20.57%	20.30%	20.07%	19.86%	19.67%	19.50%	19.34%	19.20%	19.08%	18.96%	18.86%	18.77%	18.68%	18.60%	18.53%	18.46%
Without Property Taxes and Insurance:																										
non-NYC:	19.92%	18.90%	18.05%	17.33%	16.70%	16.16%	15.68%	15.26%	14.90%	14.58%	14.29%	14.04%	13.82%	13.63%	13.45%	13.29%	13.15%	13.02%	12.90%	12.80%	12.70%	12.61%	12.53%	12.46%	12.39%	12.33%
NYC:	20.77%	19.72%	18.83%	18.08%	17.42%	16.85%	16.34%	15.90%	15.51%	15.17%	14.87%	14.60%	14.37%	14.16%	13.97%	13.80%	13.64%	13.50%	13.38%	13.26%	13.16%	13.07%	12.98%	12.90%	12.83%	12.76%

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C. Appendix 3 – Detailed Description of Econometrics Used to Estimate Energy and Ancillary Revenue

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                                                      /     /    /
                                                  ___/    /   /___/   /
                                                    Statistics/Data An

      log:  \\Nera-nycfs\Work\Projects\Energy\NYISO CAP REVIEW (K977)\Data\fin
> alreg.smcl
 log type:  smcl
opened on:   8 Jun 2007, 14:35:47

. anova lbmp load*nameind aggload*load*nameind aggload*region aggload2*region a
> ggload3*region lgasp*m*h rm*m*region h*m dow nameind tmin tmax tmean,continuo
> us(tmin tmax tmean aggload aggload2 aggload3 load rm lgasp) regress
```

Source	SS	df	MS
Model	208698154	661	315730.944
Residual	38372826.6	352614	108.823889
Total	247070980	353275	699.372954

Number of obs	=	353276
F(661,352614)	=	2901.30
Prob > F	=	0.0000
R-squared	=	0.8447
Adj R-squared	=	0.8444
Root MSE	=	10.432

lbmp		Coef.	Std. Err.	t	P>|t|	[95% Conf.	Interval]
cons		-345.8283	5.104046	-67.76	0.000	-355.8321	-335.8246
dow							
	1	-.6525151	.0666008	-9.80	0.000	-.7830508	-.5219795
	2	.2121288	.0693819	3.06	0.002	.0761422	.3481153
	3	-1.302403	.070915	-18.37	0.000	-1.441394	-1.163411
	4	-2.115483	.0708855	-29.84	0.000	-2.254417	-1.97655
	5	-2.073487	.0702348	-29.52	0.000	-2.211145	-1.935828
	6	-.1784106	.0694724	-2.57	0.010	-.3145745	-.0422468
	7	(dropped)					
nameind							
	1	-9.736149	1.140057	-8.54	0.000	-11.97063	-7.501672
	2	-4.953323	1.171597	-4.23	0.000	-7.249618	-2.657027
	3	23.8256	1.06002	22.48	0.000	21.74799	25.90321
	4	-4.159203	1.127712	-3.69	0.000	-6.369486	-1.94892
	5	29.52552	1.260031	23.43	0.000	27.05589	31.99514
	6	-618.7076	6.259504	-98.84	0.000	-630.976	-606.4391
	7	.0070146	.9856911	0.01	0.994	-1.924911	1.93894
	8	15.11848	.9037726	16.73	0.000	13.34711	16.88985
	9	-122.4719	7.169151	-17.08	0.000	-136.5232	-108.4206
	10	2.274531	1.00992	2.25	0.024	.2951175	4.253944
	11	(dropped)					
tmin		.0000704	7.59e-06	9.27	0.000	.0000555	.0000853
tmax		.2365347	.0054402	43.48	0.000	.2258721	.2471972
tmean		-.2517824	.0062505	-40.28	0.000	-.2640333	-.2395316
load*nameind							
	1	.0224741	.0013208	17.02	0.000	.0198853	.0250629
	2	.0055033	.0009131	6.03	0.000	.0037136	.0072929
	3	-.0712572	.0019125	-37.26	0.000	-.0750055	-.0675088
	4	.0091693	.0014895	6.16	0.000	.0062498	.0120888
	5	-.0491057	.0016111	-30.48	0.000	-.0522635	-.045948
	6	-.0019944	.0006748	-2.96	0.003	-.0033169	-.0006718
	7	.0068784	.0015998	4.30	0.000	.0037428	.010014
	8	-.1171817	.003428	-34.18	0.000	-.1239005	-.110463
	9	.0165023	.0011917	13.85	0.000	.0141667	.0188379
	10	-.001809	.0016808	-1.08	0.282	-.0051033	.0014853
	11	-.0010912	.0009481	-1.15	0.250	-.0029495	.0007671
aggload*region							
	1	.0338573	.000332	101.97	0.000	.0332065	.0345081
	2	.0438927	.0009693	45.28	0.000	.0419929	.0457924
	3	.1143273	.0008075	141.57	0.000	.1127445	.1159101
aggload2*region							
	1	-155.4008	1.600568	-97.09	0.000	-158.5379	-152.2638
	2	-211.0084	4.688964	-45.00	0.000	-220.1987	-201.8182
	3	-584.4934	3.997642	-146.21	0.000	-592.3287	-576.6581

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1	1	125.8605	6.75464	18.63	0.000	112.6216	139.0994
1	2	149.5712	8.312998	17.99	0.000	133.278	165.8645
1	3	123.282	13.03178	9.46	0.000	97.74008	148.8239
1	4	8.351408	15.76864	0.53	0.596	-22.55467	39.25749
1	5	56.52653	10.87527	5.20	0.000	35.21132	77.84175
1	6	128.535	8.352202	15.39	0.000	112.165	144.9051
1	7	84.60761	6.533781	12.95	0.000	71.80159	97.41363
1	8	210.4878	6.131903	34.33	0.000	198.4694	222.5061
1	9	225.3269	6.007598	37.51	0.000	213.5522	237.1016
1	10	344.968	6.627226	52.05	0.000	331.9789	357.9572
1	11	76.29325	6.261769	12.18	0.000	64.02037	88.56613
1	12	-.9870573	2.924393	-0.34	0.736	-6.718782	4.744667
2	1	127.5685	6.755039	18.88	0.000	114.3288	140.8082
2	2	135.9758	8.313121	16.36	0.000	119.6823	152.2693
2	3	120.105	13.0629	9.19	0.000	94.5021	145.7079
2	4	-1.579545	15.76862	-0.10	0.920	-32.48558	29.32649
2	5	35.003	10.87932	3.22	0.001	13.67985	56.32615
2	6	125.9554	8.356067	15.07	0.000	109.5777	142.333
2	7	88.92246	6.534258	13.61	0.000	76.1155	101.7294
2	8	220.1509	6.138443	35.86	0.000	208.1197	232.182
2	9	231.9866	6.008102	38.61	0.000	220.2109	243.7623
2	10	351.9197	6.62779	53.10	0.000	338.9295	364.91
2	11	78.19007	6.262842	12.48	0.000	65.91509	90.46506
2	12	4.478105	2.92528	1.53	0.126	-1.255358	10.21157
3	1	131.2693	6.755457	19.43	0.000	118.0288	144.5098
3	2	138.0802	8.313129	16.61	0.000	121.7867	154.3737
3	3	128.9752	13.06342	9.87	0.000	103.3713	154.5791
3	4	8.367825	15.8188	0.53	0.597	-22.63656	39.3722
3	5	55.59763	10.88314	5.11	0.000	34.267	76.92825
3	6	139.9365	8.359467	16.74	0.000	123.5522	156.3208
3	7	83.17753	6.534887	12.73	0.000	70.36934	95.98572
3	8	223.1791	6.132449	36.39	0.000	211.1597	235.1985
3	9	233.4843	6.008545	38.86	0.000	221.7077	245.2608
3	10	353.8771	6.628196	53.39	0.000	340.886	366.8682
3	11	80.89954	6.263604	12.92	0.000	68.62306	93.17602
3	12	11.2534	2.926158	3.85	0.000	5.518214	16.98858
4	1	133.1013	6.755711	19.70	0.000	119.8603	146.3423
4	2	138.3236	8.313165	16.64	0.000	122.0301	154.6172
4	3	135.6753	13.03323	10.41	0.000	110.1305	161.22
4	4	13.30386	15.76844	0.84	0.399	-17.60182	44.20954
4	5	61.87806	10.88533	5.68	0.000	40.54314	83.21298
4	6	145.0217	8.361589	17.34	0.000	128.6332	161.4102
4	7	82.95973	6.535431	12.69	0.000	70.15047	95.76898
4	8	224.2174	6.132641	36.56	0.000	212.1976	236.2372
4	9	236.8667	6.008789	39.42	0.000	225.0897	248.6438
4	10	355.1773	6.628402	53.58	0.000	342.1858	368.1687
4	11	80.32584	6.263979	12.82	0.000	68.04863	92.60306
4	12	13.25696	2.926706	4.53	0.000	7.520706	18.99322
5	1	128.8175	6.755702	19.07	0.000	115.5765	142.0584
5	2	138.9986	8.312959	16.72	0.000	122.7054	155.2917
5	3	134.6019	13.03268	10.33	0.000	109.0582	160.1456
5	4	19.67259	15.76797	1.25	0.212	-11.23217	50.57735
5	5	65.90098	10.88502	6.05	0.000	44.56667	87.23529
5	6	144.5905	8.361276	17.29	0.000	128.2026	160.9784
5	7	83.11234	6.535544	12.72	0.000	70.30287	95.92181
5	8	223.9039	6.132682	36.51	0.000	211.884	235.9238
5	9	235.2611	6.008737	39.15	0.000	223.4842	247.0381
5	10	354.2863	6.628301	53.45	0.000	341.2951	367.2776
5	11	79.88022	6.26383	12.75	0.000	67.60329	92.15714
5	12	7.907534	2.926484	2.70	0.007	2.171711	13.64336
6	1	124.7406	6.755288	18.47	0.000	111.5005	137.9808
6	2	148.8313	8.312538	17.90	0.000	132.5389	165.1236
6	3	122.934	13.03295	9.43	0.000	97.38977	148.4782
6	4	24.43395	15.76666	1.55	0.121	-6.468241	55.33613
6	5	50.07979	10.88222	4.60	0.000	28.75096	71.40862
6	6	140.4258	8.357988	16.80	0.000	124.0444	156.8072
6	7	82.80966	6.535067	12.67	0.000	70.00112	95.6182
6	8	219.9564	6.13249	35.87	0.000	207.9369	231.9759
6	9	224.9455	6.008096	37.44	0.000	213.1698	236.7212

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6	10	342.0465	6.627622	51.61	0.000	329.0566	355.0364
6	11	71.13798	6.262797	11.36	0.000	58.86308	83.41288
6	12	6.658657	2.925188	2.28	0.023	.9253738	12.39194
7	1	128.1689	6.754763	18.97	0.000	114.9297	141.408
7	2	148.3546	8.311767	17.85	0.000	132.0638	164.6455
7	3	123.2212	13.03091	9.46	0.000	97.68104	148.7614
7	4	15.60771	15.76525	0.99	0.322	-15.29172	46.50714
7	5	52.02884	10.87682	4.78	0.000	30.7106	73.34708
7	6	142.8177	8.351848	17.10	0.000	126.4483	159.1871
7	7	88.53172	6.534445	13.55	0.000	75.7244	101.339
7	8	215.3935	6.132189	35.13	0.000	203.3746	227.4124
7	9	221.0278	6.007346	36.79	0.000	209.2536	232.8021
7	10	326.6506	6.627059	49.29	0.000	313.6617	339.6394
7	11	60.37313	6.261309	9.64	0.000	48.10115	72.64511
7	12	-7.544032	2.924176	-2.58	0.010	-13.27533	-1.812732
8	1	109.2743	6.754569	16.18	0.000	96.03554	122.5131
8	2	146.6215	8.311746	17.64	0.000	130.3307	162.9123
8	3	121.7691	13.03045	9.34	0.000	96.22979	147.3084
8	4	3.167766	15.76501	0.20	0.841	-27.73119	34.06672
8	5	.1829977	10.87098	0.02	0.987	-21.12381	21.4898
8	6	105.7426	8.348091	12.67	0.000	89.38061	122.1046
8	7	69.96474	6.534173	10.71	0.000	57.15795	82.77152
8	8	205.1608	6.131913	33.46	0.000	193.1425	217.1792
8	9	212.9656	6.006882	35.45	0.000	201.1923	224.7389
8	10	311.7553	6.626981	47.04	0.000	298.7666	324.744
8	11	50.07613	6.26043	8.00	0.000	37.80587	62.34638
8	12	-16.21804	2.924161	-5.55	0.000	-21.94931	-10.48677
9	1	98.92038	6.754427	14.65	0.000	85.6819	112.1589
9	2	148.505	8.311902	17.87	0.000	132.2139	164.796
9	3	107.6447	13.02821	8.26	0.000	82.10975	133.1796
9	4	6.033114	15.76497	0.38	0.702	-24.86577	36.93199
9	5	-8.661536	10.86845	-0.80	0.425	-29.96337	12.6403
9	6	98.51986	8.347074	11.80	0.000	82.15984	114.8799
9	7	62.72644	6.534362	9.60	0.000	49.91928	75.53359
9	8	200.7758	6.131688	32.74	0.000	188.7579	212.7938
9	9	206.6993	6.00657	34.41	0.000	194.9266	218.472
9	10	309.5515	6.626925	46.71	0.000	296.5629	322.54
9	11	49.81319	6.267316	7.95	0.000	37.52943	62.09694
9	12	-18.65158	2.924333	-6.38	0.000	-24.38319	-12.91997
10	1	100.7362	6.754306	14.91	0.000	87.49792	113.9744
10	2	145.8943	8.312112	17.55	0.000	129.6028	162.1858
10	3	100.6148	13.02852	7.72	0.000	75.07931	126.1503
10	4	-.752641	15.7649	-0.05	0.962	-31.65138	30.1461
10	5	-23.34662	10.86766	-2.15	0.032	-44.64692	-2.046318
10	6	97.68044	8.347266	11.70	0.000	81.32004	114.0408
10	7	64.52759	6.534746	9.87	0.000	51.71968	77.3355
10	8	197.6266	6.131452	32.23	0.000	185.6091	209.644
10	9	198.3168	6.006345	33.02	0.000	186.5446	210.0891
10	10	302.2957	6.62692	45.62	0.000	289.3072	315.2843
10	11	55.15739	6.260015	8.81	0.000	42.88794	67.42683
10	12	-16.38365	2.924546	-5.60	0.000	-22.11567	-10.65162
11	1	101.3831	6.754247	15.01	0.000	88.14496	114.6212
11	2	146.5679	8.312275	17.63	0.000	130.276	162.8597
11	3	94.61827	13.02867	7.26	0.000	69.08246	120.1541
11	4	-8.856331	15.76467	-0.56	0.574	-39.75463	22.04197
11	5	-22.58762	10.86759	-2.08	0.038	-43.88779	-1.287458
11	6	101.0608	8.348043	12.11	0.000	84.69886	117.4227
11	7	69.16707	6.535532	10.58	0.000	56.35762	81.97652
11	8	197.3946	6.125835	32.22	0.000	185.3881	209.4011
11	9	189.6168	6.006267	31.57	0.000	177.8447	201.3889
11	10	299.843	6.626841	45.25	0.000	286.8546	312.8314
11	11	47.41218	6.259501	7.57	0.000	35.14374	59.68062
11	12	-16.91151	2.924682	-5.78	0.000	-22.64381	-11.17922
12	1	102.6006	6.754246	15.19	0.000	89.36249	115.8387
12	2	135.805	8.312495	16.34	0.000	119.5127	152.0972
12	3	85.19676	13.02893	6.54	0.000	59.66044	110.7331
12	4	-17.49812	15.76483	-1.11	0.267	-48.39672	13.40048
12	5	-36.25129	10.86777	-3.34	0.001	-57.5518	-14.95078
12	6	96.51348	8.349065	11.56	0.000	80.14956	112.8774

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12	7	56.99427	6.536925	8.72	0.000	44.18208	69.80645
12	8	188.6804	6.126129	30.80	0.000	176.6734	200.6875
12	9	187.6567	6.006232	31.24	0.000	175.8847	199.4287
12	10	293.3939	6.626909	44.27	0.000	280.4054	306.3825
12	11	45.05747	6.259471	7.20	0.000	32.78909	57.32585
12	12	-12.89598	2.924716	-4.41	0.000	-18.62834	-7.163621
13	1	109.7238	6.754248	16.25	0.000	96.48564	122.9619
13	2	133.3894	8.312649	16.05	0.000	117.0969	149.682
13	3	94.20249	13.02928	7.23	0.000	68.66549	119.7395
13	4	-16.07233	15.76519	-1.02	0.308	-46.97164	14.82697
13	5	-47.97664	10.8681	-4.41	0.000	-69.2778	-26.67547
13	6	81.77623	8.350108	9.79	0.000	65.41027	98.1422
13	7	41.48913	6.538474	6.35	0.000	28.67391	54.30434
13	8	180.6584	6.126495	29.49	0.000	168.6506	192.6661
13	9	182.3243	6.006231	30.36	0.000	170.5522	194.0963
13	10	293.8301	6.626855	44.34	0.000	280.8417	306.8186
13	11	42.43804	6.259473	6.78	0.000	30.16965	54.70642
13	12	-8.737439	2.924672	-2.99	0.003	-14.46971	-3.005167
14	1	106.6168	6.754262	15.79	0.000	93.37868	119.855
14	2	134.1205	8.312803	16.13	0.000	117.8277	150.4134
14	3	105.5055	13.02951	8.10	0.000	79.96807	131.043
14	4	-12.54139	15.76555	-0.80	0.426	-43.44141	18.35864
14	5	-47.61791	10.86844	-4.38	0.000	-68.91974	-26.31608
14	6	68.39715	8.350982	8.19	0.000	52.02947	84.76483
14	7	32.89125	6.540581	5.03	0.000	20.0719	45.7106
14	8	154.3187	6.126869	25.19	0.000	142.3102	166.3272
14	9	178.9116	6.006268	29.79	0.000	167.1395	190.6837
14	10	294.0712	6.626824	44.38	0.000	281.0828	307.0596
14	11	43.16734	6.259448	6.90	0.000	30.89901	55.43568
14	12	-4.509976	2.924597	-1.54	0.123	-10.2421	1.222148
15	1	108.7556	6.75428	16.10	0.000	95.51739	121.9938
15	2	136.4921	8.312914	16.42	0.000	120.199	152.7852
15	3	112.4051	13.02974	8.63	0.000	86.86719	137.943
15	4	-11.18659	15.76588	-0.71	0.478	-42.08726	19.71408
15	5	-51.16549	10.86882	-4.71	0.000	-72.46806	-29.86293
15	6	53.0588	8.351751	6.35	0.000	36.68961	69.42799
15	7	20.22996	6.542103	3.09	0.002	7.407632	33.05229
15	8	144.0882	6.127022	23.52	0.000	132.0795	156.097
15	9	176.6274	6.006328	29.41	0.000	164.8551	188.3996
15	10	294.5417	6.626776	44.45	0.000	281.5535	307.53
15	11	44.08334	6.259463	7.04	0.000	31.81498	56.3517
15	12	-1.601788	2.924522	-0.55	0.584	-7.333766	4.130191
16	1	107.8731	6.754347	15.97	0.000	94.63477	121.1114
16	2	135.831	8.312978	16.34	0.000	119.5379	152.1242
16	3	118.8569	13.02983	9.12	0.000	93.3188	144.395
16	4	-5.3744	15.76622	-0.34	0.733	-36.27572	25.52692
16	5	-44.17099	10.86908	-4.06	0.000	-65.47406	-22.86792
16	6	55.40359	8.355221	6.63	0.000	39.02761	71.77958
16	7	17.46309	6.543238	2.67	0.008	4.638534	30.28764
16	8	134.1745	6.126993	21.90	0.000	122.1658	146.1833
16	9	174.5491	6.0064	29.06	0.000	162.7767	186.3215
16	10	295.8014	6.626738	44.64	0.000	282.8132	308.7896
16	11	45.26661	6.259444	7.23	0.000	32.99828	57.53493
16	12	-7.006148	2.92453	-2.40	0.017	-12.73814	-1.274155
17	1	107.6921	6.754294	15.94	0.000	94.45386	120.9303
17	2	129.8928	8.312775	15.63	0.000	113.6	146.1856
17	3	113.2053	13.02941	8.69	0.000	87.668	138.7425
17	4	-5.229563	15.76616	-0.33	0.740	-36.13077	25.67164
17	5	-37.40747	10.86911	-3.44	0.001	-58.71061	-16.10434
17	6	59.14897	8.353197	7.08	0.000	42.77695	75.52099
17	7	24.27739	6.543282	3.71	0.000	11.45275	37.10203
17	8	133.0318	6.130979	21.70	0.000	121.0152	145.0483
17	9	173.5222	6.00648	28.89	0.000	161.7497	185.2947
17	10	295.013	6.626769	44.52	0.000	282.0247	308.0013
17	11	43.81296	6.259279	7.00	0.000	31.54496	56.08096
17	12	-19.48494	2.924916	-6.66	0.000	-25.21769	-13.75219
18	1	115.4385	6.754346	17.09	0.000	102.2002	128.6768
18	2	119.0781	8.312369	14.33	0.000	102.7861	135.3701
18	3	106.593	13.02841	8.18	0.000	81.0577	132.1283

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18	4	-1.699684	15.76583	-0.11	0.914	-32.60024	29.20088
18	5	-35.78397	10.86879	-3.29	0.001	-57.08648	-14.48147
18	6	74.27005	8.351866	8.89	0.000	57.90064	90.63946
18	7	37.6287	6.541083	5.75	0.000	24.80837	50.44903
18	8	145.1087	6.130637	23.67	0.000	133.0928	157.1245
18	9	178.0171	6.006544	29.64	0.000	166.2445	189.7898
18	10	295.2618	6.626842	44.56	0.000	282.2733	308.2502
18	11	19.60071	6.259219	3.13	0.002	7.332827	31.8686
18	12	-49.05892	2.925698	-16.77	0.000	-54.7932	-43.32464
19	1	103.5983	6.754411	15.34	0.000	90.35982	116.8367
19	2	109.9194	8.311947	13.22	0.000	93.62827	126.2106
19	3	78.35294	13.02657	6.01	0.000	52.82124	103.8846
19	4	-3.35741	15.76505	-0.21	0.831	-34.25644	27.54162
19	5	-21.0187	10.86826	-1.93	0.053	-42.32017	.2827709
19	6	101.9883	8.350958	12.21	0.000	85.62062	118.3559
19	7	56.15908	6.537301	8.59	0.000	43.34616	68.972
19	8	164.4163	6.142329	26.77	0.000	152.3775	176.4551
19	9	188.9281	6.006597	31.45	0.000	177.1554	200.7009
19	10	289.2643	6.626986	43.65	0.000	276.2756	302.253
19	11	19.9847	6.259258	3.19	0.001	7.71674	32.25267
19	12	-43.41021	2.925618	-14.84	0.000	-49.14434	-37.67608
20	1	107.1255	6.754405	15.86	0.000	93.88708	120.364
20	2	144.0398	8.311898	17.33	0.000	127.7488	160.3309
20	3	83.00295	13.02622	6.37	0.000	57.47194	108.534
20	4	-10.34187	15.76353	-0.66	0.512	-41.23792	20.55418
20	5	-5.788922	10.86795	-0.53	0.594	-27.08979	15.51195
20	6	115.7478	8.350213	13.86	0.000	99.38163	132.114
20	7	62.42602	6.534983	9.55	0.000	49.61764	75.23439
20	8	182.2304	6.142282	29.67	0.000	170.1917	194.2691
20	9	182.1601	6.006554	30.33	0.000	170.3874	193.9328
20	10	283.1769	6.627146	42.73	0.000	270.1879	296.1659
20	11	34.67863	6.25928	5.54	0.000	22.41063	46.94664
20	12	-29.31995	2.925379	-10.02	0.000	-35.0536	-23.58629
21	1	110.9707	6.754386	16.43	0.000	97.73231	124.2091
21	2	158.1864	8.311082	19.03	0.000	141.897	174.4759
21	3	97.31554	13.02656	7.47	0.000	71.78387	122.8472
21	4	-18.18026	15.76232	-1.15	0.249	-49.07394	12.71341
21	5	-1.54411	10.86737	-0.14	0.887	-22.84383	19.75561
21	6	114.8636	8.349521	13.76	0.000	98.49879	131.2284
21	7	70.16154	6.534785	10.74	0.000	57.35356	82.96953
21	8	180.0615	6.142642	29.31	0.000	168.0221	192.1009
21	9	184.1344	6.006629	30.66	0.000	172.3616	195.9072
21	10	297.7516	6.627051	44.93	0.000	284.7627	310.7404
21	11	38.63192	6.259343	6.17	0.000	26.36379	50.90005
21	12	-21.11747	2.925121	-7.22	0.000	-26.85062	-15.38431
22	1	114.6526	6.75438	16.97	0.000	101.4142	127.8909
22	2	158.2157	8.3122	19.03	0.000	141.924	174.5074
22	3	118.409	13.0351	9.08	0.000	92.86053	143.9574
22	4	.6220337	15.76347	0.04	0.969	-30.2739	31.51797
22	5	-10.11225	10.8672	-0.93	0.352	-31.41164	11.18714
22	6	111.5076	8.349545	13.35	0.000	95.14271	127.8724
22	7	69.17638	6.534603	10.59	0.000	56.36875	81.98401
22	8	190.7286	6.142434	31.05	0.000	178.6897	202.7676
22	9	195.4621	6.006656	32.54	0.000	183.6892	207.2349
22	10	309.747	6.626858	46.74	0.000	296.7586	322.7355
22	11	38.38221	6.259469	6.13	0.000	26.11383	50.65058
22	12	-17.59612	2.924769	-6.02	0.000	-23.32858	-11.86366
23	1	110.358	6.754413	16.34	0.000	97.11951	123.5964
23	2	147.8337	8.312603	17.78	0.000	131.5412	164.1261
23	3	105.2815	13.02911	8.08	0.000	79.74484	130.8182
23	4	5.952895	15.7657	0.38	0.706	-24.94741	36.8532
23	5	-13.13124	10.86824	-1.21	0.227	-34.43267	8.170199
23	6	95.95301	8.349134	11.49	0.000	79.58895	112.3171
23	7	72.98009	6.53341	11.17	0.000	60.1748	85.78538
23	8	195.9728	6.142327	31.91	0.000	183.934	208.0116
23	9	209.0188	6.00673	34.80	0.000	197.2458	220.7918
23	10	319.3701	6.626668	48.19	0.000	306.382	332.3581
23	11	50.48519	6.259861	8.06	0.000	38.21604	62.75433
23	12	-12.97683	2.924315	-4.44	0.000	-18.7084	-7.245258

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24 1	115.0309	6.754593	17.03	0.000	101.7921	128.2697
24 2	154.5047	8.313003	18.59	0.000	138.2114	170.7979
24 3	106.7756	13.03068	8.19	0.000	81.23586	132.3153
24 4	23.35684	15.76791	1.48	0.139	-7.547799	54.26148
24 5	-14.50447	10.87086	-1.33	0.182	-35.81104	6.802091
24 6	98.02436	8.354963	11.73	0.000	81.64887	114.3998
24 7	68.41882	6.533292	10.47	0.000	55.61376	81.22388
24 8	205.3579	6.142475	33.43	0.000	193.3188	217.397
24 9	214.1426	6.006962	35.65	0.000	202.3692	225.9161
24 10	340.187	6.626751	51.34	0.000	327.1987	353.1752
24 11	66.12409	6.260657	10.56	0.000	53.85338	78.39479
24 12	(dropped)					
aggload*load*nameind						
1	-2.28e-07	4.32e-08	-5.28	0.000	-3.13e-07	-1.43e-07
2	6.44e-08	2.92e-08	2.20	0.028	7.13e-09	1.22e-07
3	3.21e-06	6.76e-08	47.56	0.000	3.08e-06	3.35e-06
4	3.39e-08	4.91e-08	0.69	0.490	-6.23e-08	1.30e-07
5	1.95e-06	4.94e-08	39.34	0.000	1.85e-06	2.04e-06
6	-3.19e-07	3.32e-08	-9.62	0.000	-3.84e-07	-2.54e-07
7	2.71e-07	6.14e-08	4.41	0.000	1.50e-07	3.91e-07
8	6.32e-06	1.51e-07	41.88	0.000	6.02e-06	6.62e-06
9	-6.85e-07	5.70e-08	-12.00	0.000	-7.96e-07	-5.73e-07
10	5.56e-07	6.84e-08	8.12	0.000	4.22e-07	6.90e-07
11	1.77e-07	3.05e-08	5.81	0.000	1.17e-07	2.37e-07
lgasp*m*h						
1 1	14.15008	1.183027	11.96	0.000	11.83138	16.46878
1 2	12.74836	1.183164	10.77	0.000	10.42939	15.06732
1 3	10.8803	1.183335	9.19	0.000	8.560996	13.1996
1 4	9.996594	1.183454	8.45	0.000	7.677059	12.31613
1 5	12.16974	1.183491	10.28	0.000	9.850133	14.48935
1 6	14.42157	1.183421	12.19	0.000	12.1021	16.74105
1 7	14.70008	1.183359	12.42	0.000	12.38073	17.01943
1 8	24.7311	1.183412	20.90	0.000	22.41165	27.05056
1 9	29.6272	1.183377	25.04	0.000	27.30782	31.94659
1 10	29.17839	1.183367	24.66	0.000	26.85902	31.49775
1 11	28.70374	1.183333	24.26	0.000	26.38444	31.02303
1 12	27.12719	1.183303	22.92	0.000	24.80795	29.44643
1 13	22.5383	1.183272	19.05	0.000	20.21912	24.85747
1 14	23.17926	1.183277	19.59	0.000	20.86008	25.49845
1 15	21.48225	1.183286	18.15	0.000	19.16304	23.80145
1 16	21.85467	1.18332	18.47	0.000	19.5354	24.17394
1 17	26.54252	1.183334	22.43	0.000	24.22322	28.86182
1 18	29.94569	1.183488	25.30	0.000	27.62609	32.26529
1 19	32.53248	1.183574	27.49	0.000	30.2127	34.85225
1 20	28.3756	1.183551	23.97	0.000	26.05588	30.69533
1 21	24.64618	1.18348	20.83	0.000	22.3266	26.96577
1 22	20.87121	1.183357	17.64	0.000	18.55186	23.19055
1 23	20.58656	1.183197	17.40	0.000	18.26753	22.90559
1 24	18.50141	1.183133	15.64	0.000	16.1825	20.82031
2 1	38.88837	2.516645	15.45	0.000	33.95581	43.82092
2 2	45.46893	2.516698	18.07	0.000	40.53628	50.40158
2 3	44.3699	2.516715	17.63	0.000	39.43721	49.30259
2 4	44.25341	2.516742	17.58	0.000	39.32067	49.18615
2 5	43.95465	2.516727	17.47	0.000	39.02194	48.88736
2 6	39.90993	2.516677	15.86	0.000	34.97732	44.84255
2 7	42.05645	2.516574	16.71	0.000	37.12404	46.98887
2 8	42.94142	2.516549	17.06	0.000	38.00905	47.87378
2 9	42.04552	2.516555	16.71	0.000	37.11315	46.97789
2 10	43.27244	2.516565	17.20	0.000	38.34005	48.20484
2 11	42.64484	2.516579	16.95	0.000	37.71242	47.57726
2 12	46.83005	2.516607	18.61	0.000	41.89758	51.76253
2 13	46.75103	2.516605	18.58	0.000	41.81856	51.6835
2 14	45.52237	2.516617	18.09	0.000	40.58988	50.45487
2 15	43.69758	2.516631	17.36	0.000	38.76506	48.63011
2 16	44.07877	2.516634	17.51	0.000	39.14625	49.0113
2 17	48.41805	2.516625	19.24	0.000	43.48554	53.35056
2 18	59.24855	2.516676	23.54	0.000	54.31594	64.18116
2 19	65.13346	2.516669	25.88	0.000	60.20086	70.06605
2 20	45.49265	2.516634	18.08	0.000	40.56012	50.42518

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2 21	37.08969	2.517987	14.73	0.000	32.15451	42.02487
2 22	35.14162	2.51658	13.96	0.000	30.20919	40.07404
2 23	38.44176	2.516591	15.28	0.000	33.50931	43.3742
2 24	35.21118	2.516652	13.99	0.000	30.27861	40.14374
3 1	44.16021	2.943332	15.00	0.000	38.39137	49.92906
3 2	45.76235	2.970202	15.41	0.000	39.94084	51.58386
3 3	41.44623	2.970751	13.95	0.000	35.62365	47.26882
3 4	38.20098	2.944771	12.97	0.000	32.42932	43.97265
3 5	38.85579	2.944733	13.20	0.000	33.0842	44.62738
3 6	45.43176	2.945197	15.43	0.000	39.65926	51.20426
3 7	46.12193	2.944236	15.67	0.000	40.35131	51.89255
3 8	46.98568	2.943955	15.96	0.000	41.21561	52.75574
3 9	54.14137	2.942443	18.40	0.000	48.37427	59.90847
3 10	57.92125	2.942437	19.68	0.000	52.15416	63.68834
3 11	60.91691	2.942462	20.70	0.000	55.14977	66.68405
3 12	64.75718	2.942408	22.01	0.000	58.99014	70.52421
3 13	58.90743	2.942354	20.02	0.000	53.1405	64.67435
3 14	52.17799	2.942286	17.73	0.000	46.4112	57.94478
3 15	47.92477	2.942218	16.29	0.000	42.1581	53.69143
3 16	44.5131	2.942225	15.13	0.000	38.74642	50.27977
3 17	47.81902	2.942251	16.25	0.000	42.0523	53.58575
3 18	53.11538	2.942378	18.05	0.000	47.3484	58.88235
3 19	73.00695	2.942921	24.81	0.000	67.23892	78.77499
3 20	69.10102	2.943093	23.48	0.000	63.33265	74.8694
3 21	59.61843	2.943	20.26	0.000	53.85023	65.38662
3 22	46.59088	2.956324	15.76	0.000	40.79657	52.38519
3 23	52.333	2.942543	17.78	0.000	46.56571	58.1003
3 24	52.05952	2.942741	17.69	0.000	46.29183	57.8272
4 1	42.65818	3.409885	12.51	0.000	35.9749	49.34145
4 2	47.75055	3.410147	14.00	0.000	41.06676	54.43433
4 3	42.95438	3.476366	12.36	0.000	36.1408	49.76796
4 4	40.74824	3.410557	11.95	0.000	34.06365	47.43283
4 5	37.69338	3.410645	11.05	0.000	31.00862	44.37814
4 6	35.47111	3.410353	10.40	0.000	28.78692	42.1553
4 7	40.74579	3.409928	11.95	0.000	34.06243	47.42915
4 8	47.4496	3.409653	13.92	0.000	40.76678	54.13242
4 9	46.34766	3.409664	13.59	0.000	39.66482	53.0305
4 10	50.22862	3.409754	14.73	0.000	43.54561	56.91164
4 11	54.39533	3.409828	15.95	0.000	47.71216	61.07849
4 12	58.57661	3.409848	17.18	0.000	51.89341	65.25981
4 13	57.33848	3.409844	16.82	0.000	50.65528	64.02167
4 14	54.96583	3.409888	16.12	0.000	48.28255	61.64911
4 15	53.67312	3.409768	15.74	0.000	46.99007	60.35617
4 16	50.38481	3.409701	14.78	0.000	43.7019	57.06772
4 17	50.25514	3.409716	14.74	0.000	43.57219	56.93808
4 18	48.26116	3.409783	14.15	0.000	41.57809	54.94424
4 19	50.12479	3.40989	14.70	0.000	43.4415	56.80807
4 20	54.88186	3.410142	16.09	0.000	48.19808	61.56564
4 21	59.4433	3.41023	17.43	0.000	52.75935	66.12725
4 22	47.70913	3.409973	13.99	0.000	41.02568	54.39258
4 23	43.38474	3.409796	12.72	0.000	36.70164	50.06784
4 24	34.25381	3.409799	10.05	0.000	27.5707	40.93691
5 1	1.210058	5.142717	0.24	0.814	-8.869517	11.28963
5 2	12.10741	5.144109	2.35	0.019	2.025111	22.18972
5 3	1.944214	5.145481	0.38	0.706	-8.140778	12.02921
5 4	-1.029567	5.146292	-0.20	0.841	-11.11615	9.057015
5 5	-3.122553	5.146192	-0.61	0.544	-13.20894	6.963833
5 6	5.188228	5.145182	1.01	0.313	-4.896178	15.27263
5 7	5.105843	5.143487	0.99	0.321	-4.97524	15.18693
5 8	32.38254	5.141689	6.30	0.000	22.30498	42.4601
5 9	36.62187	5.14108	7.12	0.000	26.5455	46.69824
5 10	44.55995	5.141029	8.67	0.000	34.48368	54.63621
5 11	44.82272	5.141111	8.72	0.000	34.74629	54.89915
5 12	51.94591	5.141211	10.10	0.000	41.86928	62.02253
5 13	57.63893	5.141274	11.21	0.000	47.56218	67.71567
5 14	57.37014	5.141343	11.16	0.000	47.29326	67.44702
5 15	58.85538	5.14138	11.45	0.000	48.77843	68.93234
5 16	55.22817	5.141388	10.74	0.000	45.1512	65.30514
5 17	51.80568	5.141391	10.08	0.000	41.72871	61.88266

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5 18	50.34832	5.141283	9.79	0.000	40.27156	60.42509
5 19	42.38062	5.141099	8.24	0.000	32.30422	52.45703
5 20	34.7402	5.141046	6.76	0.000	24.6639	44.8165
5 21	34.4022	5.141169	6.69	0.000	24.32566	44.47875
5 22	37.01482	5.141068	7.20	0.000	26.93848	47.09116
5 23	36.40982	5.140953	7.08	0.000	26.3337	46.48594
5 24	36.35278	5.141441	7.07	0.000	26.2757	46.42985
6 1	42.4203	3.201451	13.25	0.000	36.14555	48.69505
6 2	43.21893	3.202784	13.49	0.000	36.94157	49.49629
6 3	35.94929	3.204019	11.22	0.000	29.6695	42.22907
6 4	33.36969	3.204788	10.41	0.000	27.0884	39.65098
6 5	33.52458	3.204572	10.46	0.000	27.24371	39.80545
6 6	35.6814	3.203156	11.14	0.000	29.4033	41.95949
6 7	35.17237	3.200763	10.99	0.000	28.89897	41.44577
6 8	55.17939	3.199622	17.25	0.000	48.90822	61.45055
6 9	59.29605	3.199768	18.53	0.000	53.02459	65.5675
6 10	60.43299	3.200479	18.88	0.000	54.16014	66.70583
6 11	59.42552	3.201407	18.56	0.000	53.15086	65.70018
6 12	62.05049	3.202529	19.38	0.000	55.77363	68.32736
6 13	69.81118	3.203478	21.79	0.000	63.53246	76.08991
6 14	77.20303	3.204157	24.09	0.000	70.92297	83.48308
6 15	85.19956	3.204848	26.58	0.000	78.91815	91.48097
6 16	84.46226	3.206441	26.34	0.000	78.17773	90.74679
6 17	82.42787	3.206087	25.71	0.000	76.14403	88.7117
6 18	73.88624	3.204952	23.05	0.000	67.60463	80.16785
6 19	58.99859	3.20418	18.41	0.000	52.71849	65.27869
6 20	51.70185	3.203667	16.14	0.000	45.42275	57.98094
6 21	52.64783	3.202948	16.44	0.000	46.37015	58.92552
6 22	53.35437	3.202811	16.66	0.000	47.07695	59.63178
6 23	59.98009	3.202031	18.73	0.000	53.7042	66.25598
6 24	58.08152	3.203386	18.13	0.000	51.80298	64.36006
7 1	32.76155	1.788398	18.32	0.000	29.25634	36.26676
7 2	28.47612	1.788324	15.92	0.000	24.97105	31.98118
7 3	30.59512	1.788487	17.11	0.000	27.08974	34.1005
7 4	30.41288	1.788625	17.00	0.000	26.90722	33.91853
7 5	30.17227	1.788545	16.87	0.000	26.66678	33.67777
7 6	30.53696	1.788039	17.08	0.000	27.03245	34.04146
7 7	28.04987	1.787439	15.69	0.000	24.54655	31.5532
7 8	38.07125	1.787377	21.30	0.000	34.56804	41.57445
7 9	42.17191	1.787708	23.59	0.000	38.66805	45.67576
7 10	41.37964	1.788446	23.14	0.000	37.87434	44.88494
7 11	39.5129	1.789859	22.08	0.000	36.00483	43.02097
7 12	46.48021	1.79207	25.94	0.000	42.96781	49.99262
7 13	55.55708	1.794632	30.96	0.000	52.03966	59.07451
7 14	61.04056	1.797632	33.96	0.000	57.51725	64.56386
7 15	68.60261	1.799986	38.11	0.000	65.07469	72.13053
7 16	71.02607	1.801636	39.42	0.000	67.49491	74.55722
7 17	67.45287	1.801573	37.44	0.000	63.92184	70.9839
7 18	59.23877	1.799185	32.93	0.000	55.71242	62.76512
7 19	48.09107	1.795179	26.79	0.000	44.57257	51.60957
7 20	44.04196	1.792552	24.57	0.000	40.52861	47.55531
7 21	39.9863	1.79153	22.32	0.000	36.47495	43.49765
7 22	39.83836	1.790852	22.25	0.000	36.32834	43.34838
7 23	37.87242	1.789604	21.16	0.000	34.36485	41.37999
7 24	40.98572	1.789044	22.91	0.000	37.47924	44.49219
8 1	40.42648	1.129671	35.79	0.000	38.21236	42.64061
8 2	33.96178	1.138659	29.83	0.000	31.73004	36.19352
8 3	31.80233	1.130252	28.14	0.000	29.58707	34.01759
8 4	30.95582	1.13048	27.38	0.000	28.74011	33.17153
8 5	30.91185	1.130346	27.35	0.000	28.69641	33.1273
8 6	33.01993	1.130044	29.22	0.000	30.80508	35.23479
8 7	35.38165	1.129607	31.32	0.000	33.16765	37.59564
8 8	41.04238	1.129396	36.34	0.000	38.8288	43.25597
8 9	43.8868	1.129559	38.85	0.000	41.6729	46.1007
8 10	46.25408	1.130073	40.93	0.000	44.03917	48.46899
8 11	47.20398	1.126262	41.91	0.000	44.99654	49.41142
8 12	52.57529	1.127661	46.62	0.000	50.3651	54.78547
8 13	57.3063	1.128995	50.76	0.000	55.09351	59.5191
8 14	72.53425	1.130209	64.18	0.000	70.31907	74.74942

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8 15	78.87414	1.130702	69.76	0.000	76.658	81.09029
8 16	84.68544	1.13082	74.89	0.000	82.46906	86.90181
8 17	85.41383	1.133608	75.35	0.000	83.19199	87.63567
8 18	77.73004	1.132359	68.64	0.000	75.51065	79.94943
8 19	65.69602	1.140516	57.60	0.000	63.46064	67.9314
8 20	55.38186	1.13954	48.60	0.000	53.1484	57.61533
8 21	56.56602	1.139376	49.65	0.000	54.33287	58.79916
8 22	51.00968	1.138701	44.80	0.000	48.77786	53.2415
8 23	47.0822	1.137964	41.37	0.000	44.85182	49.31258
8 24	42.78709	1.137763	37.61	0.000	40.55711	45.01708
9 1	48.88368	.7392859	66.12	0.000	47.4347	50.33266
9 2	44.97883	.7395797	60.82	0.000	43.52928	46.42839
9 3	43.9745	.7398085	59.44	0.000	42.5245	45.4245
9 4	42.01521	.7399152	56.78	0.000	40.565	43.46543
9 5	42.84971	.7398479	57.92	0.000	41.39963	44.29979
9 6	48.61707	.7394399	65.75	0.000	47.16778	50.06635
9 7	50.73702	.738973	68.66	0.000	49.28865	52.18538
9 8	55.16971	.7388318	74.67	0.000	53.72162	56.6178
9 9	59.29045	.7388241	80.25	0.000	57.84237	60.73852
9 10	64.35966	.7388677	87.11	0.000	62.9115	65.80782
9 11	69.83821	.738948	94.51	0.000	68.38989	71.28653
9 12	71.42041	.73901	96.64	0.000	69.97197	72.86885
9 13	74.49728	.7390734	100.80	0.000	73.04871	75.94584
9 14	76.76497	.7391621	103.85	0.000	75.31623	78.2137
9 15	78.1687	.7392297	105.74	0.000	76.71983	79.61757
9 16	79.58023	.7392924	107.64	0.000	78.13124	81.02922
9 17	80.26072	.7393234	108.56	0.000	78.81167	81.70978
9 18	76.75285	.7392571	103.82	0.000	75.30392	78.20177
9 19	69.78723	.7391131	94.42	0.000	68.33859	71.23587
9 20	74.473	.7390361	100.77	0.000	73.02451	75.92149
9 21	73.52978	.7389995	99.50	0.000	72.08136	74.97819
9 22	66.00541	.738964	89.32	0.000	64.55706	67.45376
9 23	57.77022	.7389304	78.18	0.000	56.32194	59.2185
9 24	54.98305	.7389807	74.40	0.000	53.53467	56.43143
10 1	46.03754	.7032583	65.46	0.000	44.65918	47.41591
10 2	42.6178	.7033538	60.59	0.000	41.23925	43.99636
10 3	41.44626	.7034302	58.92	0.000	40.06756	42.82496
10 4	40.79069	.7034502	57.99	0.000	39.41194	42.16943
10 5	41.25907	.7033819	58.66	0.000	39.88047	42.63768
10 6	48.08951	.7031715	68.39	0.000	46.71131	49.4677
10 7	57.75741	.7029339	82.17	0.000	56.37968	59.13514
10 8	65.44147	.7028578	93.11	0.000	64.06389	66.81905
10 9	66.72641	.7028522	94.94	0.000	65.34884	68.10398
10 10	70.62928	.7028687	100.49	0.000	69.25168	72.00688
10 11	72.44633	.702968	103.06	0.000	71.06853	73.82412
10 12	75.41482	.7029092	107.29	0.000	74.03714	76.7925
10 13	74.74002	.7029357	106.33	0.000	73.36229	76.11776
10 14	74.602	.7029545	106.13	0.000	73.22423	75.97977
10 15	74.00161	.7029708	105.27	0.000	72.62381	75.37941
10 16	73.10311	.7029824	103.99	0.000	71.72529	74.48094
10 17	73.66159	.7029849	104.78	0.000	72.28376	75.03942
10 18	74.05051	.7029817	105.34	0.000	72.67269	75.42833
10 19	78.74437	.7030001	112.01	0.000	77.36651	80.12223
10 20	83.49877	.7029144	118.79	0.000	82.12108	84.87646
10 21	73.35021	.7028921	104.35	0.000	71.97257	74.72786
10 22	65.14685	.7028984	92.68	0.000	63.76919	66.52451
10 23	58.87948	.7029471	83.76	0.000	57.50173	60.25724
10 24	47.79264	.7031242	67.97	0.000	46.41454	49.17074
11 1	25.70006	1.097337	23.42	0.000	23.54931	27.85081
11 2	24.59773	1.097544	22.41	0.000	22.44657	26.74888
11 3	23.11731	1.097677	21.06	0.000	20.9659	25.26873
11 4	23.40646	1.097739	21.32	0.000	21.25492	25.558
11 5	23.72781	1.097744	21.62	0.000	21.57626	25.87935
11 6	29.20061	1.097661	26.60	0.000	27.04922	31.35199
11 7	37.48038	1.097379	34.15	0.000	35.32955	39.63121
11 8	42.24839	1.097151	38.51	0.000	40.098	44.39877
11 9	42.23049	1.116062	37.84	0.000	40.04304	44.41794
11 10	39.91081	1.09733	36.37	0.000	37.76007	42.06154
11 11	43.45919	1.097	39.62	0.000	41.3091	45.60928

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11	12	44.09215	1.097009	40.19	0.000	41.94204	46.24226
11	13	44.52496	1.097046	40.59	0.000	42.37478	46.67514
11	14	43.77706	1.097041	39.90	0.000	41.6269	45.92723
11	15	42.92056	1.097045	39.12	0.000	40.77038	45.07074
11	16	42.03536	1.097038	38.32	0.000	39.8852	44.18552
11	17	46.58989	1.097058	42.47	0.000	44.43969	48.74009
11	18	66.02413	1.097152	60.18	0.000	63.87375	68.17452
11	19	61.52745	1.097138	56.08	0.000	59.37709	63.67781
11	20	51.57317	1.09711	47.01	0.000	49.42287	53.72348
11	21	47.66243	1.09706	43.45	0.000	45.51223	49.81264
11	22	46.0182	1.097025	41.95	0.000	43.86807	48.16834
11	23	37.87257	1.097033	34.52	0.000	35.72242	40.02272
11	24	29.76787	1.097174	27.13	0.000	27.61744	31.9183
12	1	56.06549	.946712	59.22	0.000	54.20996	57.92102
12	2	52.79416	.9469998	55.75	0.000	50.93807	54.65025
12	3	49.84028	.9472417	52.62	0.000	47.98371	51.69684
12	4	48.92873	.9474054	51.64	0.000	47.07185	50.78562
12	5	51.53433	.9473668	54.40	0.000	49.67752	53.39114
12	6	53.03807	.9470616	56.00	0.000	51.18185	54.89428
12	7	62.14371	.9467778	65.64	0.000	60.28805	63.99936
12	8	65.98575	.9466692	69.70	0.000	64.13031	67.8412
12	9	67.35349	.9466099	71.15	0.000	65.49816	69.20882
12	10	66.32354	.9465678	70.07	0.000	64.46829	68.17878
12	11	66.23512	.9465263	69.98	0.000	64.37995	68.09028
12	12	63.25106	.9465089	66.83	0.000	61.39593	65.10619
12	13	60.16536	.9464901	63.57	0.000	58.31026	62.02045
12	14	57.55086	.94651	60.80	0.000	55.69573	59.406
12	15	55.58739	.9465246	58.73	0.000	53.73223	57.44255
12	16	58.49908	.9465509	61.80	0.000	56.64387	60.35429
12	17	70.05863	.9466705	74.01	0.000	68.20319	71.91408
12	18	91.04836	.9468238	96.16	0.000	89.19261	92.90411
12	19	85.71378	.9468568	90.52	0.000	83.85797	87.56959
12	20	76.3678	.9468672	80.65	0.000	74.51197	78.22363
12	21	70.43553	.9468026	74.39	0.000	68.57982	72.29123
12	22	65.89274	.9466998	69.60	0.000	64.03724	67.74824
12	23	61.30307	.9465735	64.76	0.000	59.44781	63.15833
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1	1	-12.43847	4.144721	-3.00	0.003	-20.562	-4.314939
1	2	19.04658	5.832211	3.27	0.001	7.615615	30.47754
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2	1	-81.37096	4.860335	-16.74	0.000	-90.89708	-71.84485
2	2	-53.56168	6.429511	-8.33	0.000	-66.16334	-40.96003
2	3	64.12615	5.844189	10.97	0.000	52.67171	75.58059
3	1	-64.20828	11.7747	-5.45	0.000	-87.28636	-41.13021
3	2	-36.87171	12.26173	-3.01	0.003	-60.90434	-12.83907
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4	1	44.82442	14.25531	3.14	0.002	16.88444	72.76441
4	2	75.36986	14.61642	5.16	0.000	46.72211	104.0176
4	3	193.8696	14.95632	12.96	0.000	164.5556	223.1835
5	1	76.14082	2.208208	34.48	0.000	71.8128	80.46884
5	2	108.0558	5.225207	20.68	0.000	97.81455	118.2971
5	3	236.3188	4.08708	57.82	0.000	228.3083	244.3294
6	1	-72.50993	3.953374	-18.34	0.000	-80.25842	-64.76143
6	2	-49.03371	5.927865	-8.27	0.000	-60.65216	-37.41527
6	3	74.51418	4.190382	17.78	0.000	66.30115	82.72721
7	1	-9.99633	3.682982	-2.71	0.007	-17.21487	-2.777794
7	2	15.16574	5.90746	2.57	0.010	3.587292	26.74419
7	3	138.5777	4.403632	31.47	0.000	129.9467	147.2087
8	1	-139.6355	3.843065	-36.33	0.000	-147.1678	-132.1032
8	2	-116.954	5.94894	-19.66	0.000	-128.6137	-105.2942
8	3	7.89516	4.352706	1.81	0.070	-.6360162	16.42634
9	1	-165.4243	3.928385	-42.11	0.000	-173.1238	-157.7247
9	2	-143.742	5.95788	-24.13	0.000	-155.4192	-132.0647
9	3	-21.64274	4.525423	-4.78	0.000	-30.51244	-12.77305
10	1	-270.1993	4.892637	-55.23	0.000	-279.7887	-260.6099
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10	3	-127.1334	5.138372	-24.74	0.000	-137.2044	-117.0623
11	1	10.80559	4.516103	2.39	0.017	1.954164	19.65702

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11	2	38.7754	5.914102	6.56	0.000	27.18393	50.36687
11	3	152.8723	4.419392	34.59	0.000	144.2104	161.5342
12	1	18.66539	3.849982	4.85	0.000	11.11954	26.21124
12	2	48.09125	5.404089	8.90	0.000	37.49939	58.6831
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D. Appendix 4 – Guide to Demand Curve Development Model

E. Appendix 5 – Legal Notice

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