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March 21, 2005

BY HAND

The Honorable Magalie R. Salas, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E., Room 1A
Washington, D.C. 20426

Re: New York Independent System Operator, Inc.
Docket No. ER05-428-000

Dear Ms. Salas:

In connection with the March 21, 2005 Staff Technical Conference in this proceeding, the New York Independent System Operator, Inc. ("NYISO") respectfully submits the original and fourteen (14) copies of the affidavits of: (i) Dr. David B. Patton, (ii) Seth G. Parker, (iii) Belinda F. Thornton and John W. Charlton. These affiants will be speaking on the NYISO's behalf at the Technical Conference. The Commission's March 17, 2005 Notice of Agenda for the Staff Technical Conference invited speakers to submit written statements.

Respectfully submitted,

Ted J. Murphy /jak

Ted J. Murphy
Counsel for
New York Independent System Operator, Inc.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

New York Independent System Operator, Inc. **Docket No. ER05-428-000**

AFFIDAVIT OF DAVID B. PATTON, PH.D.

I. Qualifications and Purpose

1. My name is David B. Patton. I am an economist and President of Potomac Economics. Our offices are located at 4029 Ridge Top Road, Fairfax, Virginia 22030. Potomac Economics is a firm specializing in expert economic analysis and monitoring of wholesale electricity markets.

2. I currently serve as the Independent Market Advisor for the New York Independent System Operator, Inc. ("NYISO") and ISO New England Inc. ("ISO-NE"). I have served in this capacity for the NYISO since May 1999 and for ISO-NE since June 2001. As the Independent Market Advisor, I am responsible for assessing the competitive performance of the markets, including assisting in the implementation of a monitoring plan to identify and remedy market design flaws and abuses of market power. This has included preparing a number of reports that assess the performance of these markets and providing advice on numerous issues related to market design and economic efficiency.

3. I have worked as an energy economist for fourteen years, focusing primarily on the electric utility and natural gas industries. I have provided strategic advice, analysis, and expert testimony in the areas of electric power industry restructuring, pricing, mergers, and market power. I have also advised other existing and prospective RTOs on transmission pricing, market design, and congestion management issues. With regard to competitive analysis, I have provided expert testimony and analysis regarding market power issues in a number of mergers and market-based pricing cases before the Federal Energy Regulatory Commission ("Commission"), state regulatory commissions, and the U.S. Department of Justice.

4. Prior to my experience as a consultant, I served as a Senior Economist in the Office of Economic Policy at the Commission, advising on a variety of policy issues including transmission pricing and open-access policies, market design issues, and electric utility mergers. As a member of the Commission's advisory staff, I worked on policies reflected in Order No. 888, particularly on issues related to power pool restructuring, independent system operators, and functional unbundling. I also

analyzed the competitive characteristics of alternative transmission pricing and electricity auctions proposed by ISOs.

5. Before joining the Commission, I worked as an economist for the U.S. Department of Energy. During this time, I helped to develop and analyze policies related to investment in oil and gas exploration, electric utility demand side management, residential and commercial energy efficiency, and the deployment of new energy technologies. This work included the development of policies in former President Bush's National Energy Strategy and the Energy Policy Act of 1992.

6. I have a Ph.D. in Economics and a M.A. in Economics from George Mason University, and a B.A. in Economics with a minor in Mathematics from New Mexico State University.

7. The purpose of this affidavit is to discuss the attributes of the capacity demand curve that has been proposed by the NYISO staff, including whether it promises long-term benefits to the market. In addition, I will discuss the short-term costs associated with the proposed demand curve.

II. Background on the New York Capacity Market

8. The capacity market serves a very important role in maintaining adequate resources in New York over the long term by providing a vital economic signal to new and existing suppliers.

9. There are two primary sources of revenue that provide economic incentives for investment in new generating capability and for expenditures necessary to keep the most costly existing generators in operation. The first source is revenues generated in periods of shortage when prices can "spike" to levels 20 times higher than the average annual energy price. Shortages occur when the ISO cannot simultaneously meet its energy and ancillary services demands from available supplies. The second source is revenues earned from the capacity market.

10. It is the combination of the economic value of these two sources of revenues -- together with the profits earned in energy and ancillary services markets during non-shortage hours -- that govern investment and retirement decisions in the wholesale electricity markets. Markets with higher capacity revenues generally sustain higher capacity margins and, hence, exhibit less frequent and less severe price spikes associated with shortage conditions. Conversely, markets that generate lower capacity revenues will result in lower capacity margins, and more frequent shortage conditions and associated price spikes.

11. The NYISO is responsible for procuring reliability services on behalf of customers through its operating reserves and capacity markets. By establishing the capacity demand curve, the NYISO establishes the economic value that it attributes to capacity. This does not determine the price for capacity, which can range from zero up to the cap in any particular capacity auction. It is the suppliers that determine the price for capacity. In the short-run, imports and exports of capacity can vary widely to cause the capacity price in New York to equilibrate with the price or value of capacity in the adjacent markets and in Canada. In the long-run, suppliers will make investment and retirement decisions that will affect the capacity margins in NewYork and determine the price. Hence, varying the level of the demand curve would primarily affect the quantity of the capacity sold into the NYISO capacity market rather than the price.

12. In addition, the slope of the demand curve substantially affects the stability of the capacity prices in New York. Prior to the implementation of the demand curve, the New York market essentially utilized a vertical demand curve.

II. Net Revenue Offset and Historical Evidence

13. On September 22, 2004, the proposed new Capacity Demand Curves to be effective for the next three years, beginning with the 2005 to 2006 Capability Year. In my role as Independent Market Advisor, I performed an independent analysis of the historical net revenue levels in the NYISO markets and met with the NYISO and stakeholders on several occasions to discuss the results of my analysis. This

analysis provides information to assist in the development of reasonable revenue offset values for the capacity demand curves. The values proposed by the NYISO are consistent with my analysis.

14. The purpose of the net revenue offset is to reflect the fact that in the long-run, the economic signals that will guide entry and exit decisions will be a combination of revenues from the capacity market and the energy and ancillary services markets. If one were to set the demand curve at the estimated entry cost, it would produce revenues that would likely sustain a capacity surplus in New York over the long term. Therefore, while there is no single right answer, the assumed net revenues should reasonably reflect revenues expected in a market that is in equilibrium, no significant capacity surpluses or shortages.

15. Since its inception, the NYISO has exhibited a range of conditions. Initially, the market was relatively tight, which is exacerbated by the outage of the Indian Point nuclear unit. More recently, generation additions and mild weather have led to surplus conditions. I estimated net revenues for a new peaking generator in NYC and rest of state areas. For the rest of state, I assumed a Frame 7 unit located in the Capital Zone. For NYC, I assumed an LM 6000 located on the 345kv system, although I show the results for the Astoria East load pocket as well.

16. The net revenues are based on real-time prices. This is appropriate because turbines will likely be dispatched in the real-time market in response to contingencies or unexpectedly high load conditions. Additionally, real-time and day-ahead prices should converge in the long-run so that comparable net revenue should be earned by units selling into either market, although the day-ahead prices tend to show a slight premium over the real-time prices due to risk factors. Day-Ahead prices have only been lower in New York City due to modeling issues that have been resolved by the implementation of Standard Market Design. Hence, I do not expect day-ahead prices to be lower than real-time prices in New York City in the future. The following table shows the net revenue values that I estimated.

RT Annual Net Revenue ($/KW-year)

	Average Energy Net Revenue	30 Minute Revenue- 2003	Annual Energy Net Revenues 2003	2002	2001	2000
Astoria East	$89.51	$0.29	$32.49	$25.47	$41.91	$81.17
NYC 345 kV	$45.26	$0.44	$48.91	$46.49	$27.32	$81.17
Capital Zone	$7.85	$0.67	$4.88	$5.89	$8.67	$11.94
West Zone	$2.75	$0.71	$1.87	$2.42	$3.46	$3.25
Long Island	$60.33	$0.44	$34.55	$55.04	$75.66	$76.06

17. This table shows net revenue in the Capital Zone averaging more than $8.50 per kw-year, including the 30-minute reserves revenue for 2003. I include the 30-minute revenue for 2003 only because changes in the market rules regarding 30-minute reserves cause the average prices from earlier years to overstate the likely prices in the future.

18. Some have argued that the change in congestion patterns in the ROS area render the Capital Zone an inappropriate price to use for the net revenue analysis. This is not true. To the extent that the west to east congestion has shifted south to the Leeds-Pleasant Valley interface (south of Albany), the prices south of that constraint should be comparable to the historical values in the Capital Zone. If anything, the prices would be slightly higher there, resulting in higher net revenue for the 7FA turbines. Furthermore, the LAI estimated costs of installing the new 7FA units assume the turbines will be installed in the areas south of the Leeds-Pleasant Valley constraint. Therefore, demand curve parameters appropriately reflect the new congestion patterns.

19. These net revenue values do not include hours of actual or near shortages because the net revenues associated with shortage hours are added separately. To remove these hours, I removed all hours in which the price in the Capital Zone was greater than $300 per MWh. I used the Capital Zone price because high prices throughout eastern New York generally reflects shortages while high price in New York City can reflect relatively high levels of congestions into the City.

20. The actual Net Revenue associated with the shortage hours that were excluded range from close to \$6.00 per kw-year in 2003 to almost \$15 per kw-year in 2001. This range is generally consistent with the my proposal to assume an average of approximately 20 hours of shortages in the long-run, which would produce roughly \$10 per kw-year of net revenue assuming a shortage price of \$1000 in these hours.

21. Therefore, the total net revenue for the Capital Zone would be \$18.50 per kw-year (\$10.00 plus \$8.50) and \$54.70 in NYC. These values are consistent with the offset values proposed by the NYISO of \$15 for the ROS and \$59 for NYC, prior to the winter adjustment of \$5 per kw-year.

22. It is important to recognize that there is no one "right" offset value, only a reasonable range. The offset should reflect a reasonable expectation of the net revenue that would be earned when the market is in long-run equilibrium. Hence, while it is true that a number of new units have been added that were not on the system during the period of our analysis, it is also true that the result is a substantial current capacity surplus in the ROS that would depress net revenue values. Hence, recent net revenues (e.g., 2003-2004) that have occurred under the prevailing capacity surplus and during relatively mild load conditions cannot be considered representative of expected net revenues in long-run equilibrium.

III. Net Revenue Assumptions

23. The assumptions I used to calculate these net revenues are shown in the following table:

Net Revenue Assumptions

	ROS	NYC
Technology	7FA	LM6000
Size (MW)	300	90
Heat Rate (BTU/KWh)	11000	10500
Levitan Heat Rate (BTU/KWh)	10635-11127	9528-9961
Start-up Cost (\$/MW)	\$36	\$10

24. The heat rates shown in the table above from the Levitan study include internal unit load and the degradation of the unit's efficiency over time. The range shown is related to the effects of ambient temperatures on the heat rates. The highest heat rate in the range corresponds to 90 degree ambient temperature. As the table shows, the heat rate we assumed was consistent with the high end of the range, which is appropriate because it ensures that net revenue will generally only be attributed to the unit when it is economic.

25. The start-up cost values are based on fuel-based start-up costs for the twin units of $5770 for the 7FA and $320 for the LM6000 units, based on the start-up fuel requirements reported in the Levitan study and a $5 per MMbtu fuel price. In addition, I assumed non-fuel start-up costs of $8000 for each 7FA turbine and $300 for each of the LM6000 turbines based on data in a filing by ISO-NE in its locational ICAP proceeding. These values result in a per MW start cost of approximately $72 and $10 for the 7FA and LM6000, respectively. I assume the 7FA will recover these costs over a 2 hour average run-time and the LM6000 would recover its over a 1 hour run-time.

26. Amortizing the start costs over such a short timeframe should appropriately address the fact that owners of such units will require an expectation that they will cover their start-up costs and earn some incremental profit before they will be willing to start their units. However, it is unreasonable to assume an owner of a 7FA would require that its unit always recover its start cost in a single hour since it would lose profit in any periods when it would be economic to run for more than one hour.

27. With regard to the LM6000 assumptions, the assumed heat rate is slightly higher than Levitan values and the start-up costs are assumed to be recovered over a single hour. Both of these assumptions bias the estimated costs on the high side. In addition, because LM6000 units can start within 10 minutes, they could be eligible to provide 10 minute reserves. If I had adjusted the assumptions to recognize these factors, the net revenue for NYC would have been slightly higher. This further supports the NYISO proposed offset value, which is roughly $5 higher than the estimated historical values.

IV. Market Power and the Slope of the Demand Curve

28. It is important to recognize the effect of the slope of the demand curve in mitigating incentives to withhold capacity from the market to raise capacity prices. The proposed ICAP demand curves results by design in modest price increases as the total level of capacity offered in the capacity market decreases, which reduces the incentive of large suppliers to withhold their resources from the capacity market.

29. I conducted a simple analysis to illustrate how the demand curve changes the incentives of suppliers to withhold capacity from the market. The following table shows the maximum profit a supplier of different sizes can earn by withholding resources when the market exhibits various levels of surplus under the proposed capacity demand curve.

		Size of Supplier		
		1000	2000	3000
Surplus	500	$ -	$ -	$ -
	1000	$ -	$ -	$ -
	1500	$ -	$ -	$ 160
	2000	$ -	$ -	$ 1,576
	2500	$ -	$ 160	$ 4,458
	3000	$ -	$ 1,576	$ 8,804
	3500	$ 160	$ 4,458	$ 14,615
	4000	$ 1,576	$ 8,804	$ 21,892

30. These results show that larger suppliers will generally have a larger incentive to withhold than smaller suppliers. However, this table shows that the profit that can be expected by withholding under the capacity demand curve is relatively modest due to the shallow slope of the supply curve.

31. Interestingly, the incentive to withhold goes to zero as the market approaches the minimum capacity requirement level. This result is driven by the fact that the cost of withholding increases as the market moves toward deficiency since the supplier must forego revenues from the withheld capacity at the pre-withholding price. Therefore, when the surplus is large and the capacity price is near zero, the cost of withholding capacity is low.

32. If changes are made that increase the slope of the supply curve, the mitigating effect of the supply curve will be reduced. Hence, this should be considered in changing the parameters of the demand curve.

33. This concludes my affidavit.

ATTESTATION

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

David B. Patton

March 21, 2005

Subscribed and sworn to before me
this 21st day of March, 2003

Notary Public

My commission expires: 4.30.07

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION)

New York Independent System Operator, Inc.) **Docket No. EL05-428-000**
Respondent.)

AFFIDAVIT OF SETH G. PARKER

SETH G. PARKER, being duly sworn, deposes and says:

1. My name is Seth G. Parker. I am a Vice President and Principal of Levitan & Associates, Inc. ("LAI"), a management consulting firm specializing in energy markets and economics. LAI is located at 100 Summer Street, Suite 3200, Boston, MA, 02110.

2. I am an economic and financial manager with an international background in power and fuel project development, evaluation, financing, and transactions. I have been responsible for modeling and analyses of independent and utility-owned projects, as well as market design, regulatory policy, contract restructuring, and asset valuation assignments.

3. Prior to joining LAI I worked as a consultant and officer of Stone & Webster Management Consultants where I was responsible for due diligence reviews of many proposed power, fuel, and infrastructure projects in the U.S. and abroad. This work was conducted for commercial banks, investment banks, multilateral lending agencies, and other financial institutions. I have also worked in the

Treasurer's Office at Pacific Gas & Electric, and at ThermoElectron Energy Systems and J. Makowski Associates (project development firms).

4. My educational background includes an Sc.B. in Applied Mathematics / Economics from Brown University, and M.B.A. in Finance / Operation Research from the Wharton Graduate School at the University of Pennsylvania. I have taught undergraduate-level finance as an adjunct faculty lecturer, and taken additional course work in Basic Gas Turbine Technology and International Political Economy.

5. I have presented expert witness testimony before a state public utility commission, U.S. District Court, and before the American Arbitration Association on matters concerning power plant economics and markets. I have submitted expert reports on similar matters as well. My resume and a list of my expert testimony and reports is attached.

6. Neither LAI nor I have any personal financial interest in any Market Participant or in any transaction in the New York Independent System Operator ("NYISO") market.

Demand Curve Study for NYISO

7. Last year NYISO retained LAI to analyze certain parameters in connection with establishing the demand curves for the upcoming installed capacity ("ICAP") spot market auctions for the 2005/06, 2006/07, and 2007/08 planning years. I was responsible for managing that assignment. LAI delivered a Report to NYISO on August 16, 2004, and issued an Update to our report on September 1, 2004.

8. The demand curves are intended to provide ICAP revenues required by gas turbine peaker plants to achieve specified financial targets after consideration of net revenues from sales of energy and ancillary services. The demand curve parameters that LAI calculated included capital costs, fixed operating costs, variable costs, and performance values for gas turbines peakers. We prepared a projection of delivered fuel costs, forecasted net energy and ancillary service revenues for the peakers, estimated financial assumptions, and prepared levelized ICAP revenue requirements ("Reference Values"). NYISO adjusts these Reference Values for differences in summer/winter supply curves to prepare values used to set the actual Demand Curves ("Reference Points").

9. LAI analyzed the proposed demand curves with respect to ICAP price volatility, the potential exercise of market power, and the net cost to load of having ICAP above the NYISO target quantity.

10. During the course of our work, LAI reviewed these parameters with a stakeholder group organized by NYISO that consisted of representatives from generation companies ("Gencos"), load-serving entities ("LSEs"), the New York Public Service Commission ("NYPSC"), and other market participants.

Gas Turbine Capital Cost Assumptions

11. LAI decided that the appropriate peaker technology was aeroderivative gas turbines for New York City ("NYC") and Long Island ("LI"), and industrial frame gas turbines for Rest-of-State ("ROS") based on actual and planned gas turbine projects. In NYC and LI, about twenty gas turbines have been installed, consisting of one or two aeroderivative units per site, in the past few years. Most

of those aeroderivative gas turbines are GE LM6000 units. No industrial frame peakers have been installed in NYC or LI in the past few years.

12. In ROS a few industrial frame peaker projects have been proposed and have applied for permits, but none has actually been installed. At least two industrial frame peaker projects have been installed in the Pennsylvania-New Jersey-Maryland Interconnection ("PJM") market, two units at one site and four units at another site. All of those industrial frame gas turbines are GE 7FA units. The City of Jamestown Board of Public Utilities installed an aeroderivative gas turbine at an existing site in ROS that was designed for combined cycle operation, not as a peaker. LAI evaluated the Jamestown capital cost, as described in Appendix C of our Report, and found that it could not be utilized because there were too many significant questions and adjustments that would be required. For example, the Jamestown plant was at an existing site; the power island (*i.e.* the gas turbine, electric generator, instrumentation / control system, and other equipment that is typically provided as a package by the vendor) contract did not reflect normal market conditions; the project was able to avoid gas pipeline and labor mobilization costs; and the plant cost included a heat recovery steam generator (unnecessary for a simple cycle peaker) but excluded selective catalytic reduction (necessary in our analysis).

13. The capital cost of a gas turbine peaker plant is the most important component in estimating the required ICAP revenues. LAI estimated the capital costs for the power island packages, by obtaining vendor quotes, with the assistance of our sub-contractor DMJM+Harris, for LM6000 and 7FA units. Balance-of-plant and

other capital cost items were based on other data sources, as explained in our Report. Appendix C in the Report breaks down LAI's capital cost estimates into six main categories, with 21 individual line items (excluding two line items not utilized). The capital cost of the peaker plant in ROS was updated on September 1st. Our capital cost estimates, with unit capital costs at 59°F and the gas turbines in new clean condition, are as follows:

Table 1: Gas Turbine Peaker Capital Costs (2004 Dollars)

	NYC	LI	ROS
Capital Cost	$114.0 million	$108.1 million	$201.5 million
/ Net Capacity	/ 96.0 MW	/ 96.0 MW	/ 336.5 MW
Unit Capital Cost	$1,189/kW	$1,126/kW	$599/kW

14. Local siting issues are very important in determining peaker costs. Land (whether purchased or leased) and labor costs are more expensive in NYC and LI than in ROS. LAI's subcontractor, DMJM+Harris, utilized standard industry cost indices for labor and bulk construction materials in different geographic regions in our estimate of plant capital costs.

15. We verified our capital cost estimates against actual cost data for comparable peaker projects wherever possible, such as the ten units at six NYC sites installed by the New York Power Authority ("NYPA"). As detailed in Appendix C of our Report, the NYPA costs are within 2%-3% of the LAI estimates when reasonable and necessary adjustments are made.

16. Since the publication of our Report and Update, a consultant for ISO-New England ("ISO-NE") prepared capital costs for an industrial frame gas turbine peaker plant consisting of a single 7FA unit. Those capital costs were included in

the ISO-NE proposal filed at FERC to implement a Locational ICAP ("LICAP") mechanism. Ignoring adjustments for one unit versus two units per site, dual fuel versus single fuel capability, etc., ISO-NE presented a range of costs, \$560/kW - \$620/kW, that brackets and supports LAI's \$599/kW cost estimate for ROS.

17. PJM has conducted stakeholder meetings and intends to file a Reliability Pricing Model ("RPM") with FERC to implement an ICAP auction using demand curves. PJM's consultant has presented preliminary capital cost data for a 2x7FA gas turbine plant that is about 22% below our cost estimate. We do not have sufficient detailed data to understand the source of the difference with PJM.

Gas Turbine Performance Assumptions

18. LAI estimated the performance of the peaker plants based on vendor performance data, *i.e.* gross capacity and gross heat rate using lower heating values ("LHV"), adding in station loads, heating value adjustments, and average long-term levels of performance degradation that would be encountered in actual operation.[1] The resulting net heat rates reflect operation at full load, and are not intended to represent part-load peaker efficiency. We calculated net capacity and net heat rate values at 59°F, *i.e.* standard ISO conditions, and at 25°F winter temperature and 90°F summer temperature conditions for dispatch simulation modeling purposes. Our performance values at 59°F are as follows:

Table 2: Gas Turbine Peaker Performance

[1] Lower heating value ("LHV") is typically the basis used by vendors for gas turbine fuel consumption and heat rate data. Fuel is purchased on a higher heating value ("HHV") basis.

	Aeroderivative 2xLM6000	Industrial Frame 2x7FA
Gross Capacity	98.0 MW	343.4 MW
- Station Load	- 2.0%	- 2.0%
Net Capacity	96.0 MW	336.5 MW
- Avg. LT Degradation	- 0.0%	- 3.0%
LT Net Capacity	96.0 MW	326.4 MW
Gross Heat Rate (LHV)	8,527 Btu/kWh	9,360 Btu/kWh
* HHV / LHV	* 1.11	* 1.11
Gross Heat Rate (HHV)	9,458 Btu/kWh	10,390 Btu/kWh
- Station Load	+ 2.0%	+ 2.0%
Net Heat Rate (HHV)	9,647 Btu/kWh	10,597 Btu/kWh
- Avg. LT Degradation	+ 1.0%	+ 3.0%
Net Heat Rate (HHV)	9,739 Btu/kWh	10,809 Btu/kWh

19. LAI verified our performance estimates against actual performance data for comparable projects where possible. Most of the NYPA LM6000 peaker projects in NYC consist of two gas turbines at a site, and are limited to a total net output of 80 MW. When both units at a site are dispatched, they cannot be operated at full output, their most efficient operating level. Any heat rate comparison must account for this limitation. In addition, the NYPA heat rate data may include fuel used during start-ups. Any adjustment to exclude start-up fuel should be based on actual operating data.

20. ISO-NE submitted gas turbine heat rate data in the LICAP to FERC. ISO-NE identified a range of 9,000 - 10,400 Btu/kWh (LHV) for an industrial frame peaker, and 8,100 - 9,200 Btu/kWh (LHV) for an aeroderivative gas turbine. When the mid-point values are taken and converted to HHV, the industrial frame heat rate is 10,670 Btu/kWh, and the aeroderivative heat rate is 9,515 Btu/kWh. Both of these values are very close to and support the values estimated by LAI.

21. ISO-NE utilized a value of 4.5% for 7FA station loads and degradation in its LICAP filing to FERC. This value is very close to and supports LAI's combined value of 5.1% for a 2x7FA gas turbine plant. PJM has presented a preliminary heat rate of 10,440 Btu/kWh (HHV) that is very close to and supports our value of 10,390 Btu/kWh (HHV) before station loads and degradation.

22. The Independent Power Producers of New York, Inc. ("IPPNY"), have claimed that that 7FA gas turbines have minimum run times of 4 hours.[2] LAI did not assume any minimum run time in our dispatch simulation modeling. We confirmed that there is no technical or operational basis for a minimum run time with a GE sales representative and with an owner of a 7FA peaker plant in PJM. Submitting a bid with a minimum run time is a commercial issue determined by a plant owner in concert with other financial and market factors.

Gas Turbine Operating Cost Assumptions

23. LAI estimated the variable operating costs of the peaker plants using confidential in-house data and confidential data provided by some of the generation stakeholders. The principal variable operating cost is accruals for required maintenance activities. We assumed a variable operating cost of $3/MWh for the 7FA gas turbine in our Report, plus a quantity of fuel for start-up. LAI checked the variable operating cost assumption by estimating maintenance costs over a complete maintenance cycle, as shown in the table below. Contrary to what some

[2] *See Motion to Intervene, Supporting Comments and Limited Protest of Independent Power Producers of New York, Inc* ("IPPNY")., Docket No. ER05-428-000 at 15; Exhibit 1, *Affidavit of Mark D. Younger* ("Younger") at ¶ 7 (January 28, 2005).

have claimed,[3] although it might be reasonable to use a variable operating cost somewhat above $3/MWh, a much higher cost could not be justified. In any event, higher variable operating costs would tend to cause peaker plants to bid higher prices that, in turn, would maintain their net energy revenues. Therefore utilizing a higher variable operating cost would not make a material difference in our forecast of net energy revenues, particularly for a 7FA peaker in ROS.

Table 3: Variable Operating Costs for Maintenance (2004 Dollars)

Maintenance Activity	Hours	Est'd Cost (millions)	Maintenance Activities / Cycle	Cost (millions)
Combustion Inspection	8,000	$3	4	$12.0
Hot Gas Path Inspection	24,000	$4	1	$4.0
Major Inspection (O/H)	48,000	$8	1	$8.0
			Total	$24.0
			Hours	48,000
			Cost (/hr)	$500.0
			Capacity (MW)	163.2
			Cost (/MWh)	$3.06

24. IPPNY has claimed that starting costs should include $8,000/start for a 7FA gas turbine.[4] These starting costs are actually accruals for required maintenance activities. According to GE, the timing of 7FA gas turbine maintenance activities is based on independent criteria of starts and of operating hours.[5] Whichever criterion is first reached determines the maintenance interval for the three major

[3] *See, e.g., Motion to Intervene, Protest, and Comments of Keyspan-Ravenswood, LLC* ("Keyspan"), Docket No. ER05-428 at 25-26 (January 28, 2005).

[4] *See* Younger at P 7.

[5] GE reference document GER-3620K (12/04), Heavy-Duty Gas Turbine Operating and Maintenance Considerations.

maintenance activities – combustion inspections, hot gas path inspections, and major inspections. If the start criterion is used, $8,000/start is a reasonable value. LAI used the operating hour criterion, but would not oppose utilizing a start criterion. However, we forecast that the 7FA peakers in ROS would operate at such low capacity factors, *i.e.* close to 0% under deterministic load treatment and about 1% under stochastic load treatment. If we assume the maximum number of starts for a 1% capacity factor, *i.e.*, 88 starts/year and 1 operating hour/start, it would take more than 27 years for a 7FA peaker in ROS to complete a maintenance cycle. Therefore, using a start criterion would not make a material difference in our calculation of 7FA net energy revenues in ROS.

25. LAI estimated fixed operating expenses by reviewing a number of data sources, both in-house and provided by NYISO stakeholders. Property taxes are the largest component in our estimate. In order to confirm the reasonableness of our estimate, we compared our 7FA ROS values with those filed by ISO-NE and presented to the PJM RAM stakeholders, as shown below. LAI's estimate is very close to and is supported by the ISO-NE value. The PJM value is significantly lower, and we do not have sufficient detailed data to understand the source of our difference with PJM.

Table 4: Gas Turbine Peaker Fixed Operating Costs (2004 Dollars)

NYISO (LAI)	ISO-NE	PJM
$19.96/kW	$20.78 - $25.69/kW	$11.94/kW

26. LAI estimated the fixed costs of a gas turbine peaker by estimating each specific cost element – property taxes, staffing, contract services, insurance, site lease, and

general & administrative services. We used confidential in-house data and confidential data provided by some of the generation stakeholders to derive these estimates, as described in our report. Property taxes account for over two-thirds of the total fixed operating costs. Maintenance costs were accrued entirely as variable operating costs.

27. Keyspan has questioned our assumptions concerning the NYC property tax rate and its application to peaker plants.[6] We based our estimate of NYC property taxes on confidential in-house data and on data provided by a generation stakeholder. We found that the data varied considerably, since older plants had low property taxes that reflect lower assessed values. It would be incorrect to base a long-term property tax assumption on a new plant value, because plant value will decline over time. Therefore our resulting 2004 estimate of $25.66/kW-yr for a NYC peaker (Table 4, page viii) is a reasonable basis for the twenty year levelized value built into our demand curves, and is consistent with property tax estimates for LI and ROS.

28. Keyspan also challenges our assumption that peakers may avoid fixed transportation charges imposed by local distribution companies ("LDCs").[7] As explained in our Report, LAI evaluated historical local transportation tariffs and have found that generators, especially peakers with relatively low capacity factors, can negotiate with the LDCs to avoid fixed transportation charges. As a

[6] Keyspan at 23-24.

[7] Keyspan at 23.

consequence, the volumetric charges that we assume are designed to allow the LDC to recover both fixed and variable transportation costs.

Net Energy Revenue Calculations

29. LAI forecasted the net energy and ancillary service revenues that a peaker would be likely to earn by simulating the hourly operation of the peakers under expected market conditions. LAI used a chronological dispatch simulation model, MarketSym, that takes into account the major transmission constraints within New York and between New York and the surrounding markets of New England, Quebec, Ontario, and PJM.

30. We included all known near-term generation additions and retirements in our simulation modeling as shown in Tables 16 and 17 of our Report. We added generic simple cycle and combined cycle resources to the markets to maintain required reserve margins over the long term. Since Special Case Resources ("SCRs") provide ICAP, we included SCRs when adding these generic resources.

31. LAI used the 2002 load shape provided by NYISO in our simulation modeling.[8] This load shape was adjusted in every year so that the system peak loads and annual loads matched the forecast values under normal weather conditions in the 2004 Load and Capacity Data Report (also referred to as the "Gold Book") prepared by NYISO. The 2002 load shape has two benefits. First, the 2002 load shape was used in the Installed Reserve Margin ("IRM") study that determined

[8] In actuality, the 2002 load shapes were provided by zone, and LAI aggregated those load shapes to correspond to our modeling topography. This permitted LAI to incorporate an additional level of accuracy in our simulation modeling.

NYISO's required reserve margin. This ensures consistency between the need for ICAP and the market mechanism to encourage ICAP. Second, the 2002 load shape was the most recent of the load shapes under consideration, and therefore the most likely to reflect current structural changes in customer usage patterns.

32. Our decision to use the 2002 load shape is supported by the 2004 IRM Study, which refers to the decision by the Installed Capacity Subcommittee to adopt the 2002 load shape instead of the previously used 1995 load shape. The "Average Curve", derived from the years 1993 - 2002, is not useful because it is relies on antiquated data and does not reflect current structural changes. The 2003 IRM Study used a base case load curve that was very similar to the 2002 load shape, and decided not to use the 1998 load curve. The 2005 IRM Study also uses the 2002 load shape.

33. Some have claimed the 2002 load shape is inappropriate for a long-range forecast.[9] Given that the Installed Capacity Subcommittee found that the previous 1995 load shape was "antiquated" and "the zonal components do not adequately represent recent load growth patterns," any load shape based on data prior to 2002 would be inappropriate. The Installed Capacity Subcommittee considered the 2003 load shape, and decided not to utilize it in preference to the 2002 shape.

34. LAI conducted a set of dispatch simulations in which load was treated deterministically, *i.e.* is known with certainty for unit commitment purposes, similar to unit commitment in the day-ahead market. In order to forecast the

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[9] Keyspan at 10-13

operation of gas turbine peakers during the occasional and unexpected demand spikes (during which energy prices rise) in the real-time market, LAI conducted a set of dispatch simulations in which load was treated stochastically, *i.e.* we introduced random variations around the 2002 load shape. LAI derived statistical measures based on historical load data, and used a "Monte Carlo" feature to vary our forecast of loads. Monte Carlo is a standard modeling technique, in which a random variable is used to change a feature of the simulation model, in this case the loads. We conducted fifty simulations for three selected years, calculated average dispatch levels and net energy revenues, and interpolated those results over the entire forecast horizon. Stochastic treatment of load is one way, but not the only way, to simulate peaker dispatch in the real-time market.

35. LAI checked our dispatch simulation results in a number of ways, including examining the forecasted average capacity factors for gas turbine peakers in NYC. We found that in 2005, the first year we simulated, gas turbine peakers in NYC would achieve an average capacity factor of 15% with deterministic loads and 19% with stochastic loads. These results are consistent with the most recently published historical data. LAI calculated an average 2003 capacity factor of 16.2% for the NYC peakers, based on net energy and capacity data in the NYISO 2004 Gold Book for the ten LM6000 peaker gas turbines owned by NYPA. In fact, this 16.2% capacity factor is probably conservative, since eight of the ten peakers are limited to 40 MW, considerably below their average capacity of 46 MW. The 2004 Gold Book forecasts NYC peak load to increase by 1,068 MW from 2003 to 2005, and LAI increased the Zone J installed capacity by a similar

amount, *i.e.* 975 MW, over the same period. Therefore, the demand and supply factors that determine peaker dispatch should be similar for 2003 and 2005, and, LAI's forecasted NYC peaker dispatch values of 15% - 19% in 2005 are reasonable.

36. Keyspan has also claimed that LAI's forecast is too optimistic with respect to NYC peaker dispatch, based on a forecast NYC peaker capacity factor of 3% for 2005 using GE MAPS, another dispatch simulation model.[10] This claim is suspect for a number of reasons. First, it is claimed that the simulation was performed for Zone J. If the simulation did not include the transmission links to other zones and with the surrounding markets, then the simulation was incomplete. The details of the GE MAPS simulation were not presented, and any meaningful review is therefore not possible. Second, it appears that certain "adjustments" to the model inputs were necessary because GE MAPS provided an "unrealistic" peaker capacity factor of less than 0.1% with normal input assumptions. The adjustments included lowering the variable operation and maintenance ("O&M") cost to $1.00/MWh, and eliminating the LDC gas transportation charge. These adjustments are themselves not realistic, particularly when the same intervener argues that LAI's variable O&M assumption of $3.00/MWh is too low and should be $7.00/MWh, and therefore casts doubt on the reasonableness of the intervenors' results. Third, there is no claim that a 2005 NYC peaker 3% capacity factor is correct, merely that the LAI value is too high

[10] Keyspan at 12.

in comparison. As described above, LAI demonstrated that our results are close to recent historical data, and there is no support that a 3% capacity factor is realistic.

37. Keyspan has alleged that it was inconsistent for LAI to treat load stochastically, but not fuel.[11] LAI considered treating gas prices stochastically, and determined that gas price volatility occurs primarily during the winter heating season. Gas prices and energy prices are more highly correlated during the winter heating season compared to the rest of the year. This correlation would tend to leave spark spread, and hence net energy revenues, for peakers unaffected. Therefore we did not pursue stochastic treatment of gas prices.

38. Keyspan has claimed that a 27% correlation exists between Transco Zone 6 gas prices and NY Zone J on-peak energy prices, and therefore net energy revenues are overstated. The claimed correlation does not support this conclusion. First, it is unclear how a correlation can be determined between daily gas price data and hourly on-peak energy price data. If the hourly on-peak energy price data was averaged on a daily basis, then valuable hourly price data would be smoothed out and lost. Second, although a 27% correlation is not statistically insignificant, it would be statistically correct to classify it as a weak correlation with limited descriptive and predictive power. Third, higher gas prices would tend to cause peakers to bid higher energy prices, in which case any gas-to-energy price correlation would have little if any impact of net energy revenues.

[11] Keyspan at 24-25.

Net Ancillary Service Revenues

39. The LM6000 aeroderivative gas turbines are capable of achieving full load operation in ten minutes. While the NYPA units were not designed to and do not provide ten minute non-spinning reserves ("TMNSR"), other aeroderivative units do provide TMNSR. In its LICAP filing to FERC, ISO-NE assumed that LM6000 units can provide TMNSR. LAI assumed that the NYC and LI peakers would receive TMNSR revenues for the purposes of this assignment.

40. The 7FA industrial frame gas turbines are capable of achieving full load operation in thirty minutes with a normal starting sequence, given sufficient notification and preparation. LAI assumed that ROS peakers would receive thirty minute reserves ("TMR") revenues for the purpose of this assignment. This is consistent with ISO-NE's LICAP filing to FERC. LAI confirmed this assumption with a GE representative and with an owner of a 7FA peaking plant in PJM.

Financing Assumptions

41. LAI proposed financing costs used to levelize the net energy and ancillary service revenues that we forecast. In our Report we explained that "Given the paucity of pure merchant project financings and the unique differences among plants, it is virtually impossible to precisely determine those capital [financing] costs." Therefore LAI based our financing costs on discussions with lenders, equity investors, and other market participants. We note that financing costs filed at FERC by ISO-NE, after the Report was published, are very close to our values. We also note that financing costs being considered by PJM are also very close to our values. All three sets of financing costs are shown in the table below.

Table 5: Financing Assumptions

	NYISO (LAI)	ISO-NE	PJM
Inflation Rate	3.0%	2.5%	2.5%
Construction Debt	5.0%	3.5%	3.5%
Permanent Debt Rate	7.5%	7.0%	7.0%
Permanent Debt Term	20 yrs	20 yrs	20 yrs
Debt / Equity Ratio	50% / 50%	50% / 50%	50% / 50%
Equity Rate of Return	12.5%	12.0%	12.0%
Plant Depreciation	15 yr MACRS	15 yr MACRS	15 yr MACRS
Income Tax Rate	39.9%	41.1%	41.5%

42. The period over which investors expect to recover their investment and earn their equity return is also impossible to precisely determine. LAI's assumption of a twenty year capital recovery period is consistent with my personal experience, with the permanent debt term, and with the IRS classification of gas turbines as 20 year property (asset class 49.15) with a 20 year recovery period. Keyspan has claimed that a 15 year life is more reasonable because the IRS permits 15 year accelerated depreciation. However, investment property can be depreciated over a shorter life, but that is for income tax purposes and ignores the IRS classification as 20 year property.

Demand Curve Analysis

43. LAI analyzed the demand curves that we calculated by testing the economic incentives for a supplier to withhold capacity to maximize revenues and by calculating the total cost of ICAP to each regional market. Total ICAP costs were calculated with and without postulated withholding, as well as under alternative zero-crossing points. LAI made no recommendations to change the slope of the demand curves or zero-crossing points, due in part to the limited analysis we conducted. We recommended that any change to the demand curve slope or the

zero-crossing points should be based on a more rigorous analysis using the final 2005 demand curves filed by NYISO with actual supply bid data. At this point, we have no reason to believe the NYISO adjustments to reference values calculated by LAI would alter our recommendation to maintain the zero-crossing points.

44. LAI supports the concept and NYISO's application of a (sloped) demand curve. LAI recognizes that the Demand Curves would be based on input from the Market Participants and other sources as well as its analysis. LAI believes that NYISO's ICAP mechanism that utilizes a demand curve will generally achieve its objectives of dampening UCAP price volatility, encourage timely plant entry at appropriate locations, discourage market power abuses, and recognizes the reliability and energy price benefits of capacity above target reserve margins.

45. This concludes my Affidavit.

SETH G. PARKER

ATTESTATION

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

Seth G. Parker

March 21, 2005

Subscribed and sworn to before me
this 21st day of March, 2005

Notary Public

My commission expires: 4.30.07

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

New York Independent System Operator, Inc. **Docket No. ER05-428-000**

JOINT AFFIDAVIT OF
BELINDA F. THORNTON
and
JOHN W. CHARLTON

STATE OF NEW YORK)
) ss
COUNTY OF ALBANY)

BELINDA F. THORNTON and JOHN W. CHARLTON, being duly sworn, depose and say:

1. Belinda F. Thornton, being duly sworn, deposes and states as follows. I am Assistant Vice President, Corporate Product Management of the New York Independent System Operator, Inc. ("NYISO"), an independent not-for-profit corporation organized under the laws of the State of New York. Since August, 2004, I have been responsible for and deeply involved in the development of the ICAP Demand Curves. I joined the NYISO in July 2001 and served as Director of Regulatory Affairs until July 2004. At that time, I became Assistant Vice President, Market Services with responsibilities over the Installed Capacity ("ICAP") and Transmission Congestion Contracts ("TCC") markets. In February

2005, the Corporate Product Management group was formed and the ICAP and TCC market responsibilities were transferred into that new organization, and I assumed responsibility for the new group.

2. Belinda F. Thornton further states: I have more than 24 years of electric utility experience including marketing product development and administration, wholesale power trading, development and administration of wholesale power purchase/sales agreements, and management of regulatory processes. Prior to joining the NYISO, I worked for the Tennessee Valley Authority holding various management and staff positions in Bulk Power Trading, Transmission/Power Supply, and Marketing. I received my B.S. degree from the University of Alabama and M.B.A. degree from the University of Tennessee at Chattanooga.

3. John W. Charlton, being duly sworn, deposes and states as follows. I am the Program Coordinator for the Installed Capacity/Resource Adequacy Programs of the NYISO. I was first employed by the NYISO in October of 2000 as a Senior Engineer. I have held the position of Program Coordinator since September of 2003. In this capacity, and as Senior Engineer, I have been and continue to be responsible for market designs and applications of Capacity and Resource Adequacy (Installed Capacity) in New York.

4. John W. Charlton states: I have more than 42 years of experience in electric system planning, operations, engineering, reliability, and maintenance. Prior to joining the NYISO, I was employed by New York State Gas & Electric Corp. for 31 years and Public Service Electric & Gas Co. for 7 years. I also served as an Adjunct Lecturer for Power Systems studies at Binghamton University for a

decade. I received my B.E.E. from Union College and M.S.E.E. degree from Newark College of Engineering. I am a registered Professional Engineer in the State of New York.

5. The NYISO operates the State of New York's high voltage electric transmission system and administers the state's competitive wholesale electricity markets. The NYISO is responsible for assuring the reliability of the New York State power system and has no financial interest in any transaction for the generation or transmission of electricity.

Installed Capacity Demand Curves in the New York ICAP Market

6. The purpose of this affidavit is to explain what Demand Curves are, and to describe how the NYISO staff used input from expert analysts, interested stakeholders, and its own independent judgment to develop proposed Demand Curves.

7. The NYISO-administered ICAP market contributes to maintaining an adequate level of generating resources in New York. In concert with earnings in the Energy and Ancillary Services markets, ICAP market revenues provide the economic signals and incentives to encourage investment in new generating capacity and for making the expenditures necessary to maintain the viability of more costly existing generators.

8. Under the "Stage I" ICAP market that was implemented soon after the inception of the NYISO, minimum ICAP requirements for all Load Serving Entities ("LSEs") were set at the forecasted NYCA peak demand plus a reserve margin ("ICAP Requirement"). The reserve margin is established by the New York State

Reliability Council, and has historically been set at 18% of forecasted peak demand. Under the Stage I ICAP design, supplies in excess of the ICAP Requirement had no market value, and ICAP market prices became quite volatile during Capability Periods[1] when the available capacity was close to the required levels and rapidly transitioned into a nearly vertical demand curve at the minimum ICAP Requirement, meaning that capacity prices dropped to very low levels or near zero above the minimum requirement.

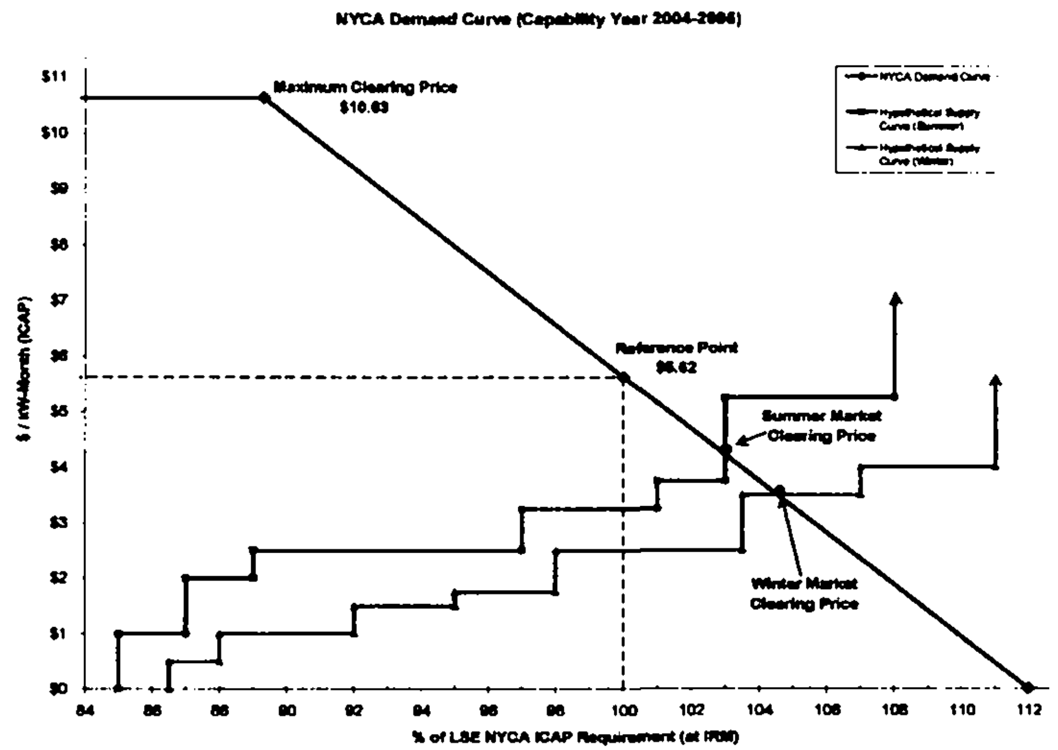
9. In early 2003, therefore, the NYISO proposed tariff amendments to the Commission to implement ICAP Demand Curves in the ICAP spot market auctions for the Summer 2003 Capability Period and thereafter. The Commission approved implementation of the Demand Curves, effective May 2003. The NYISO's Demand Curve proposal was the result of a significant developmental effort that included all sectors of NYISO stakeholders during 2002 and was approved by the Market Participants through the NYISO governance process.

10. Separately-determined ICAP Demand Curves were put in place for three localities: one each for the New York Control Area as a whole (also referred to as the "NYCA"); the New York City Load Zone ("NYC"), and the Long Island Load Zone ("LI"). As approved by the Commission, the Demand Curves are to be adjusted periodically in accordance with the NYISO Tariff and ISO Procedures, which we will describe in more detail below.

11. For each of the three areas, the sloped Demand Curves pass through two price

[1] Each year is divided into two Capability Periods, a Summer Capability Period May 1 to October 31, with the remaining months in the Winter Capability Period.

points that determine the slopes of the curves. The first price point, the Reference Point, is set on the vertical line established by the quantity of the ICAP Requirement at a point representing the levelized fixed cost of a new peaking unit, net of energy and ancillary services revenues. The second price point is $0, set at a point on the ICAP Supply axis in excess of the ICAP Requirement (the "Zero Crossing Point") that produces Demand Curves with an appropriate slope consistent with the objectives of the Demand Curves, and above which ICAP is deemed to have no value. For ICAP quantities less than the applicable ICAP Requirement, the sloped Demand Curves extend to a maximum clearing price of 1.5 times the levelized cost of a new gas turbine. Currently, the Zero Crossing Point for the NYCA is set at 112% of the minimum ICAP Requirement. For NYC and LI, the Zero Crossing Point is 118% of the minimum ICAP Requirement. A graphic example of the NYCA Demand Curve for the current capability year is included below:



12. The Demand Curves have three principal objectives. First, to recognize that some capacity supply above the minimum ICAP Requirement provides an additional reliability benefit to the system and reduces the frequency of energy price spikes, the Demand Curves provide clearing prices and revenues for these additional supplies. Second, the Demand Curves substantially reduce if not eliminate the volatility that was inherent in the prior market by not having the capacity price fall to zero as soon as the ICAP Requirement is met or rise to extreme levels for minor shortages of resources. The sloped Demand Curves result in more stable and efficient capacity price signals for potential new capacity investment. Third, the Demand Curves support bilateral arrangements among LSEs and suppliers by providing a more stable expectation of market clearing prices for capacity.

Phase-in Period to Implement Full Demand Curve Values

13. From their May 2003 introduction into the New York markets, the Demand Curves were phased in so that the Reference Values (levelized capacity revenue requirement to recover capital and fixed operating costs after net Energy and Ancillary Services revenues) would move to the net cost of entry for a new peaking turbine over a three-year period. Demand Curve values for each of the first two years of the phase-in— the 2003/2004 and 2004/2005 Capability Years— were based on Reference Values set at approximately 60% and 80% of the full values, respectively. As required by the Demand Curve provisions in the NYISO tariff, and the NYISO ICAP Manual provisions that were approved by Market Participants in 2003, the third-year transition to 100% of full values for the 2005/2006 Capability Period will be completed by the initial periodic review process that resulted in the filing in this docket. The periodic review process began with an independent review of the Demand Curve parameters, and a NYISO proposal for adjustments of the Demand Curve values, and will conclude with the Commission's approval of Demand Curve values for the 2005/2006, 2006/2007, and 2007/2008 Capability Years.

Periodic Review and Adjustment of Demand Curve Values

Independent Review of Demand Curve Values

14. Beginning in the spring of 2004, Levitan & Associates, Inc. ("LAI") of Boston, Massachusetts, performed the required independent review of the Demand Curve parameters. LAI was selected after a competitive process, based on its extensive expertise and experience in similar engagements. ICAP market stakeholders were significantly involved from the very beginning of the independent review process.

Through the ICAP Working Group, a subcommittee of the NYISO Business Issues Committee, stakeholders had previously reviewed and provided input to the NYISO's Request for Proposal seeking an independent consultant to perform the study. Following the selection of LAI to perform the review, LAI personnel attended ICAP Working Group meetings throughout the late spring and summer of 2004 to review with, and receive feedback from, stakeholders on the assumptions that would be used in the LAI study.

15. LAI was engaged to independently assess: (i) the estimated annualized levelized fixed cost for constructing and operating a typical new gas turbine (the "Fixed Cost") in each of the three New York localities; and, (ii) projections of Energy and Ancillary Services revenues, net of fuel costs, that these hypothetical new peaking units could expect to earn in the New York markets (the "Net Revenue Offset"). As specified in the NYISO tariff, the Fixed Cost values for a new gas turbine in each of the three localities, reduced by the Net Revenue Offset values, results in the Reference Values used to determine the Reference Points for new Demand Curves. LAI also analyzed the relative slopes of the three Demand Curves that would result from these Reference Values and alternative zero crossing points to determine the potential incentive for ICAP suppliers to withhold their capacity.

16. The purpose of the LAI study was to provide a detailed analysis which the NYISO staff could use to determine proposed Demand Curves for review by the stakeholders and the NYISO Board of Directors ("Board"). The LAI study was not intended to establish the revised Demand Curves.

17. Throughout the course of its independent review, LAI representatives met with stakeholders to report on their progress and to explain and receive feedback about their underlying assumptions. Beginning with an April 22, 2004, ICAP Working Group meeting, LAI provided an overview of its approach to the study, indicating that it intended to model a typical peaking plant as a pair of gas turbines, assumed to be located at an appropriately zoned site without other existing generating facilities already in place. LAI also outlined the "MarketSym" revenue modeling methodology that it intended to utilize to derive estimates for Net Revenue Offset values. MarketSym is a licensed chronological dispatch simulation model. LAI also outlined how it would translate its study results into annualized levelized fixed costs, provided a project schedule, and responded to numerous questions from stakeholders.

18. At a May 27, 2004 ICAP Working Group meeting, LAI provided a more extensive presentation to stakeholders, including preliminary results of its typical peaking plant Fixed Cost and Net Revenue Offset estimates, and presented preliminary Demand Curve values for the three localities. LAI representatives also again participated in an extensive question and answer exchange with stakeholders and NYISO staff.

19. On August 16, 2004, LAI issued its *Independent Study to Establish Parameters of the ICAP Demand Curves for the New York Independent System Operator* ("LAI Study"). On September 1, 2004, LAI issued an addendum to its Study which reduced its original Fixed Cost estimate for a gas turbine plant in the NYCA, based on additional information on capital cost estimates that LAI developed as a

result of stakeholder input after the August 16th issuance of the LAI Study. The full LAI Study and the September 1, 2004 addendum were included with the NYISO's January 7, 2005, filing of proposed new Demand Curves with the Commission.

20. The LAI Study reflected estimates of Net Revenue Offsets under two different scenarios. First, LAI modeled Energy and Ancillary Services revenues over the 20-year recovery period that was assumed for a typical gas turbine unit on a deterministic basis. This approach assumes a "perfect" forecast of expected loads and planned generator additions plus new capacity as required, to meet the projected load growth profiles and, as a result, provides a lower revenue forecast than would models giving greater weight to forecast uncertainties and price spikes. Second, LAI also modeled Revenues over the same period on a stochastic basis. The stochastic approach models loads probabilistically, rather than as fixed forecasts, resulting in more price volatility and higher forecasted Net Revenue Offsets. Both the deterministic and the stochastic methods model loads on an hourly basis and thus do not capture unpredictable intra-hour events such as generator or transmission outages which could result in more price spikes and consequently higher Net Revenue Offsets. Demand Curve values from the LAI Study under the deterministic and stochastic approaches for the three localities were:

Revenue Modeling Approach	NYCA	NYC	LI
Capital and fixed operating costs	$87	$176	$155
(less deterministic net revenues)	($0)	($24)	($7)
Deterministic Reference Values	$87	$152	$148
(less additional stochastic net revenues)	($7)	($24)	($13)
Stochastic Reference Values	$80	$128	$135

21. After analyzing the potential economic incentives for ICAP suppliers to withhold capacity as well as the total cost of ICAP under the Demand Curve values, LAI found no compelling basis to adjust the existing Zero Crossing Points for the Demand Curves. The NYISO staff reached the same conclusion.

Stakeholder Review of Independent Study Results

22. According to the NYISO ICAP Manual, the next step in the Demand Curve adjustment process requires the NYISO staff to assess the results of the independent review and receive feedback from the New York Public Service Commission ("NYPSC") and stakeholders. During August and September 2004, stakeholders and the NYPSC provided written and verbal feedback to NYISO staff. Dr. David Patton, the NYISO's Independent Market Advisor, discussed his independent analysis of the Net Revenue Offsets and other issues with stakeholders.

NYISO Proposal for New Demand Curves, Appeals, and Board Action

23. Following the stakeholder feedback process and consultation with Dr. Patton, the NYISO staff issued proposed new Demand Curve values on September 22, 2004, and issued a clarification on September 30, 2004, which further explained the rationale and basis for NYISO staff's proposed Demand Curve values. For its

proposed ICAP Demand Curve values, the NYISO adopted the Fixed Costs determined by the LAI Study. Informed by the Net Revenue Offsets developed by LAI and Dr. Patton's analysis of historical Energy and Ancillary Services revenues as additional data points, NYISO staff developed what it judged to be a complete estimate of Net Revenue Offset expectations under a scenario of a reasonably tight market condition of available capacity compared to load requirements and reflecting realistic operating conditions that were not and could not have been reflected in any predictive model. The NYISO staff's proposed Demand Curve Reference Values, comprised of Fixed Costs less Net Revenue Offsets, for the three localities were:

NYISO Proposal	NYCA	NYC	LI
Fixed Cost	$87	$176	$155
- Net Revenue Offset	- 20	- 50	- 40
Reference Value ($/kW-yr)	$67	$126	$115

24. Under the Demand Curve adjustment procedures in the ICAP Manual, stakeholders submit comments on the NYISO staff proposal to the Board, which is responsible for adopting final new Demand Curve values for filing with the Commission. Accordingly, during October 2004, stakeholders submitted initial and responsive comments on the NYISO proposal to the Board. On November 15, 2004, the Market Performance Committee of the Board heard oral arguments from stakeholders in support of their earlier written submissions. Following oral arguments, the Board was also advised by Dr. Patton that he had performed an

independent analysis of historical net revenue levels in the NYISO markets and had discussed his analysis on several occasions with stakeholders and NYISO staff. Dr. Patton indicated that his analysis should be utilized to assist in the development of reasonable revenue offset values for the Demand Curves and opined to the Board that the values proposed by the NYISO staff were consistent with his analysis. Finally, Dr. Patton informed the Board that, after having heard the stakeholder presentations to the Board, it remained his opinion that the NYISO staff's proposed new Demand Curve parameters were both reasonable and consistent with the underlying objectives for the Demand Curves.

25. On December 21, 2004, acting on a recommendation on that same date from the Market Performance Committee, the full Board voted unanimously to adopt the new Demand Curve values that were previously proposed by the NYISO staff. At the Board's direction, these proposed values were submitted to the Commission on January 7, 2005.

Basis and Rationale for NYISO Proposal

26. To propose new Demand Curves that would provide the correct economic signals for new generation investment in the New York markets, NYISO staff sought to develop values that would reasonably reflect the estimated cost to enter the New York energy markets with new peaking units in the three localities. NYISO staff also recognized that the assumptions underlying the estimates of construction and operating costs and revenues for a hypothetical new gas turbine could cover a wide range, and would be assessed differently along the spectrum of supplier and purchaser interests. NYISO staff, therefore, sought to develop proposed new

Demand Curves according to a set of study assumptions that were consistent and would, as reasonably as practicable, fairly reflect a supportable and sound engineering estimate of the cost of developing and operating a new gas turbine.

27. The adoption of an outlying or extreme value for any one limited subset of the numerous variables in costs, such as site location or choice of equipment, would ignore the inherent interdependency among these variables. For example, a stakeholder seeking the lowest possible value for a discrete variable might argue that the location assumption for the NYCA peaking turbine should have been in western New York where construction and land costs would be lower. This variable cannot be considered in a vacuum, however, since lower energy prices prevail in those load zones and the Net Revenue Offset for this scenario would have to be adjusted accordingly. Similarly, stakeholders representing loads have advocated lower Demand Curve Values, but did not appear to reflect in their proposals the costs of the additional risk to a developer whose revenue stream, under this proposed alternative, would depend more on the volatility of energy price spikes.

28. Consequently, NYISO staff, after considering the stakeholder feedback for adopting differing variables and assumptions, elected to further modify the LAI Study results in order to reflect a reasonable independent outcome. The ICAP Manual's procedures for adjusting the Demand Curve parameters provides for stakeholder feedback concerning the independent review, to be followed by a NYISO proposal taking into account the stakeholder feedback to adjust the results of the independent review as appropriate.

Annualized Levelized Fixed Costs

29. NYISO staff concluded that the annual Fixed Cost recommendations in the LAI Study, with the September 1, 2004 update, were based on a significant amount of commercial intelligence that was available to LAI and also reflected reasonable engineering estimates of the costs of building a generic simple cycle gas turbine in each of the three localities. NYISO staff also concluded that the financing and recovery period assumptions reflected in LAI's derivation of an annualized levelized Fixed Cost were reasonable in light of current market conditions. NYISO staff concluded that the LAI assumptions also fairly balanced the interests of stakeholders who suggested that the selected financing variables were too low and others seeking lower curve values who contended that the terms were unnecessarily expensive. Accordingly, these annual Fixed Cost determinations were adopted without modification as the foundation for the Demand Curve proposal.

30. During the review and feedback process, some stakeholders cited similar studies of peaking unit costs that have recently been performed by the PJM Interconnection ("PJM") and ISO New England ("ISO-NE") for the proposition that the LAI Study's results for annual Fixed Costs in New York were too high. The NYISO concluded, however, that the differences in Fixed Costs were reasonably consistent with those studies considering locational differences (*i.e.* cost to build in New York) and the alternative assumptions used in those studies.

31. For example, the ISO-NE study assumed the installation of a single generating unit, whereas LAI assumed, and the NYISO agreed, that a typical project in New

York will more than likely include two generators at a new site in order to take advantage of economies of scale, given that the same investment level in common facilities and site preparation can accommodate a second unit. The PJM study assumed that a new generic peaking unit would be constructed at an existing generating site with minimal infrastructure costs such as an electrical substation and a natural gas pipeline for fuel delivery. LAI considered that a typical new peaking unit would be sited according to a number of difficult to project criteria and, thus, concluded that the most reasonable approach would be to assume that the projected facilities would be constructed on sites that would require investments in electrical substation and gas pipeline equipment in addition to the other typical common facilities that were reflected in the PJM study. The NYISO determined that this approach, although higher in capital costs, better reflected what would be the more likely scenario for constructing the new gas turbines in New York.

Net Revenue Offset

32. In considering the Net Revenue Offsets to include in its proposal for new Demand Curve values, the NYISO assessed the underlying characteristics of both the deterministic and the stochastic revenue modeling scenarios developed by LAI. The NYISO considered that the price volatility reflected in the entirety of the stochastic results might not be representative of the New York markets. The early years of the stochastic results do not reflect tight market conditions, and the 20-year study does not reflect price volatility during intra-hour events like generator or transmission outages and resulting price spike revenues.

33. On the other hand, the deterministic modeling results, which assume virtually perfect foresight in load forecasts and, thus, do not reflect temporary price spikes under shortage conditions, were also perceived by NYISO staff to be unrealistic and thus problematic as a sole basis for deriving Net Revenue Offsets.

34. Accordingly, NYISO staff determined that constructing an estimate for Net Revenue Offsets within a range between the deterministic and the stochastic model results plus adding a scarcity pricing factor, would better reflect both actual experience in the operation of the New York energy markets and the balance between operating and capacity revenue streams in these markets. Consequently, NYISO staff considered two beginning data points. With respect to the NYCA locality, for example, the deterministic revenue results of the LAI Study were in the $1 to $2 per kW/year range, without scarcity conditions. Dr. David Patton also analyzed historical results in the New York markets and estimated that a marginal unit in the rest-of-state ("ROS"), the area in the NYCA outside the NewYork City and Long Island zones) might earn up to $8 per kW/year of Net Revenue Offset, exclusive of scarcity. The LAI stochastic study suggests a Net Revenue Offset in the $8-$10 range is reasonable without considering unpredictable scarcity conditions.

35. Dr. Patton further concluded that a reasonable estimate of scarcity condition-related revenues would be $10, reflecting scarcity conditions for 20 hours of each year. This is a conservative estimate for a marginally tight market with a slight capacity excess. Adding this scarcity factor to both the deterministic results and Dr. Patton's historical analysis, the NYISO concluded that a typical marginal

peaking turbine in the NYCA might reasonably expect to receive between $12 and $18 of Net Revenue Offset. Similar ranges for deterministic and historic non-scarcity values plus the $10 scarcity component for NYC and LI were $43 and $65, and $22 and $60, respectively.

36. Balancing the potential for overly conservative results from the LAI Study's deterministic approach against Dr. Patton's non-weather normalized historical analysis, NYISO staff concluded that $15 of net revenues would be reasonably representative of the combined expectations of non-scarcity and scarcity conditions for a new NYCA peaking turbine. Similarly, for NYC and LI the NYISO elected to adopt Net Revenue Offsets of $50 and $40, respectively.

Winter Revenue Benefit for NYCA

37. In deriving the proposed Demand Curves for the NYCA, the NYISO used a ratio of winter-to-summer capacity in the NYCA capacity market equal to 1.037. This ratio of reported winter and summer Dependable Maximum Net Capabilities ("DMNCs") was derived from the 2004 Load and Capacity Data (the "Gold Book"), which is readily and publicly available.

38. The Gold Book DMNC data reflects approximately 1,400 MW of winter capacity that should be available in the NYCA market in the winter Capability Period compared to the summer Capability Period. The lower winter temperatures enable units to produce higher outputs compared to those in the summer Capability Period. The higher capacity available in the winter tends to reduce winter capacity market prices. Accordingly, the Demand Curve Reference Point is set so that the total of the summer and winter period market prices would equal

the annual Reference Value (annual Fixed Cost less Net Revenue Offset) when the summer capacity just equals the minimum NYCA capacity requirement.

39. If the actual additional winter capacity in the NYCA ICAP market going forward is less than the 1,400 MW seasonal differentiation in DMNCs that was derived from the Gold Book data, an empirical analysis shows that a marginal gas turbine would realize additional revenues of approximately $1/kW-year for each decrement of 100 MW of actual supply participation in the ICAP markets below the 1,400 MW seasonal performance difference assumption.

40. In fact, during the last two winter Capability Periods, the winter capacity available to the NYCA was only about 600 MW higher than the summer capacity. The 800 MW difference between the 1400 MW excess imputed in the Demand Curve and the actual 600 MW excess experienced would therefore result in about an $8 winter revenue benefit. However, generation resources being added within the NYCA would serve to increase the internal higher winter capacity from 1400 to 1700 MW and result in lower winter revenues of approximately $3. The NYISO therefore included a winter revenue benefit of $5 within the Net Revenue Offset to correct for the difference between the Gold Book winter/summer capacity differences and actual experience.

41. The main reason for this winter adjustment is that Hydro Quebec ("HQ") is a winter peaking control area and does not export any significant capacity in winter to insure its own system reliability. Indicative of actual expectations for ICAP supplies in excess of the ICAP Requirement, the Hydro Quebec control area, alone, has provided an average of about 740 MW and 880 MW less capacity

supply in the most recent 2002/2003 and 2003/2004 winter periods, respectively, compared to each winter's preceding summer. Under current market rules in ISO-NE and PJM, it is expected that the ISO-NE and PJM interfaces will be substantially full for the foreseeable future.

42. NYISO staff did not apply this winter revenue benefit within the Net Revenue Offset to the proposed Demand Curves for NYC and LI. The Demand Curves for NYC and LI are strictly based on capacity located within these Localities and the slope of their Demand Curves correctly estimates the relative sizes of the summer and winter markets. Experience has shown that the actual committed capacity in these markets tracks the Gold Book ratio. These localities would receive the winter revenue benefit in the NYCA portion of the ICAP obligations.

Zero Crossing Point and Slope of Demand Curves

43. As indicated earlier, the slopes of the Demand Curves are a function of the monthly Reference Points, which are derived from the Reference Values, and the Zero Crossing Point along the capacity supply matrix. Because the Commission approval for the Demand Curves in 2003 established that the initial Zero Crossing Points would be applicable for the three-year phase-in period, the third year of which is the first year of the NYISO proposal here, and because the LAI Study did not recommend altering these points based on its review of the potential for withholding, NYISO staff concluded that the benefits of stability and continuity for the market supported maintaining the existing Zero Crossing Points. In addition to stability, with the current points the NYISO's Market Monitoring & Performance unit has not observed any significant economic or physical

withholding of capacity supplies since the implementation of the Demand Curves. This has been reported to the Commission in the NYISO's first two annual reports that are required under the original Demand Curve order.

44. Lowering the Zero Crossing Point would tend to increase the incentives to withhold and could lead to increased volatility. Increasing this point reduces the incentive, but would increase ICAP purchase obligations for loads. The current parameters appear to be effective and, lacking any compelling study results or stakeholder evidence to change them, NYISO staff does not propose to alter the Zero Crossing Points now.

Sensitivities Among Proposals in Monthly Spot Market Clearing Prices

45. To compare the relative sensitivity of market clearing prices under the range of suggested Demand Curve values, NYISO staff has developed estimated summer and winter Spot Market Auction clearing prices under the NYISO's recommended NYCA Demand Curves and representative Reference Values advocated by stakeholders representing loads and stakeholders representing capacity suppliers. To develop hypothetical supply bid curves, NYISO staff assumed a New York ICAP Requirement of 37,860 MW for the 2005/2006 Capability Year, which is approximately 400 MW above the current Capability Year value. NYISO staff further assumed the current level of ICAP supplier commitments and added one-half of the net capacity additions planned for the 2005/2006 Capability Year. The results of this analysis are summarized in the following table:

	NYISO	Load	Supplier
Reference Values	$67/kW-year	<$62/kW-year	>$72/kW-year
Reference Points	$6.78/kW-month	<$6.27/kW-month	$7.29/kW-month
Possible Market Clearing Prices	Summer - $1.46/kW-month	Summer - $1.35/kW-month	Summer - $1.57/kW-month
	Winter – $0.69/kW-month	Winter – $0.64/kW-month	Winter – $0.74/kW-month
Estimated Annual Revenues	$13	<$12	>$14

46. As this analysis suggests, probable Spot Market Auction results are not significantly sensitive to the differences between the NYISO, load, and capacity supplier proposals, and the NYISO values represent intermediate values between the values urged by loads and suppliers. While summer monthly market clearing prices under the NYISO's proposed Demand Curve values for the NYCA would be $1.46 per kW/month under the hypothetical load and supply values indicated in the preceding paragraph, the clearing price would be only $0.11 less under the Demand Curves suggested by loads, and $0.11 higher than the NYISO's proposal under the Demand Curves suggested by capacity suppliers.

ATTESTATION

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

John Charlton

March 21, 2005

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

Belinda Thornton

March 21, 2005

Subscribed and sworn to before me
this 21st day of March, 2005

Notary Public

My commission expires: 4.30.07