STATE OF NEW YORK DEPARTMENT OF PUBLIC SERVICE

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October 1, 2007

SENT VIA E-MAIL
Ms. Karen Antion
Chair, NYISO Board of Directors
c/o Diane Egan (degan@nyiso.com)
Dave Lawrence (dlawrence@nyiso.com)
New York Independent System Operator, Inc.
10 Krey Boulevard
Rensselaer, NY 12144

Re: Proposed NYISO Installed Capacity (ICAP) Demand Curves for Capability Years 2008/2009, 2009/2010, and 2010/2011

Dear Ms. Antion:

Attached, please find the Department of Public Service's comments regarding the NYISO's proposed ICAP Demand Curves for Capability Years 2008/2009, 2009/2010, and 2010/2011.

Very truly yours,

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BEFORE THE BOARD OF DIRECTORS
OF THE NEW YORK
INDEPENDENT SYSTEM OPERATOR

New York State Department of Public Service Comments Regarding Proposed NYISO Installed Capacity (ICAP) Demand Curves for Capability Years 2008/2009, 2009/2010, and 2010/2011

INTRODUCTION AND SUMMARY

On August 31, 2007, the NYISO issued its final report (Report) proposing revised ICAP Demand Curves for the three Capability Years, beginning May 1, 2008, and ending April 30, 2011. In accordance with Appendix B of the Report, the Staff of the New York State Department of Public Service (DPS Staff) hereby submits its comments for consideration by the NYISO Board of Directors (Board).

DPS Staff commends the NYISO and its consultants for preparing this comprehensive Report and for working with stakeholders to address their comments and concerns. While further modifications should be made to the Report to ensure it is reasonable, we support the NYISO's decision to remove the risk factor that assumed generators might only recoup 50 percent of the targeted capacity revenues. This risk factor is duplicative and unnecessary since the Report already includes a 12 percent return on equity (ROE) that captures the risk associated with merchant generators. Moreover, such a risk factor would be biased, since it is also possible that generators may recoup more than the targeted capacity revenues as a result of tighter capacity margins. For example, regulatory hurdles in siting new generation or transmission facilities, and the retirement of existing generation, including the expected closure of NYPA's Poletti generating station by January 31, 2010, may tighten available capacity.

In addition, DPS Staff supports the recommendation to develop the NYC and LI Demand Curves based on the LMS-100 peaking unit technology, as opposed to the older LM6000. The consultants concluded that the LMS-100 is a more efficient technology with a lower average cost. The Report observes that five LMS-100 units have been proposed by NRG as a market solution in the Comprehensive Reliability Planning Process, further demonstrating the viability of this technology. Moreover, deferring the switch to the newer LMS-100 until the next reset of the Demand Curve would impose a 35 percent increase (about $50/kW-year) in the NYC reference price, despite only a 14 percent increase in the estimated cost of an LM6000. The 35 percent increase would be due to the consultant's unprecedented excess capacity adjustment.[1] The resulting 3-year spike in the NYC reference price, followed by a huge decrease with a switch to the LMS-100 during the next Demand Curve reset, would impose unnecessary costs and confusion on the NYC capacity market.

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[1] See NERA's Independent Study to Establish Parameters of the ICAP Demand Curve for the New York System Operator, p. 11, Table I-3 and p. 79, Table A-7.

We note that the Report relies on the quoted vendor prices, which may not reflect the vendor's best offer, and therefore may tend to inflate the Demand Curve reference prices. Given that generators will likely be reluctant to provide actual cost data and it will therefore be difficulty to accurately measure these costs, the Board should consider the quoted prices as a conservative (i.e., high) estimate, thereby obviating the need to build additional conservatism into the Demand Curve, as discussed below.

DPS Staff is primarily concerned with three key assumptions within the Report that appear to be overly conservative and unnecessarily inflate ICAP reference prices, especially for the statewide market. The first two assumptions relate to the expected levels of excess capacity and net energy/ancillary services revenues. Given the significance of these two key assumptions, they should be closely scrutinized by the Board. Although prices will ultimately be determined as a result of the ICAP auctions, the recommendations in the Report will likely translate into a significant increase in Rest-of-State (ROS) ICAP prices. The Report proposes a reference price of $9.09/kW-month for ROS for the first Capability Year, which represents a 25 percent increase over the current $7.30/kW-month reference price, despite the fact that the Report estimates a far lower increase (i.e., only 5.3 percent) in the installed cost of a peaking unit in upstate New York.[2] This disparity highlights the import of the Report's assumptions and the need to ensure these assumptions are reasonable.

The tariff states that ICAP reference prices should be computed "under conditions in which the available capacity would equal or slightly exceed the minimum Installed Capacity Requirement."[3] To the extent an excess capacity level is modeled, it should reflect both the expected average size of new generators, as well as the pattern in which they can be expected to be added to the system. As such, we recommend an average level of three percent in excess of the minimum capacity requirement for NYC, which translates to 300 MW, and an average level of one percent in excess of the minimum requirement for the entire New York Control Area (NYCA), which translates to 400 MW.[4]

Regarding the level of net energy and ancillary services revenues, the Report underestimates the amount of these revenues because it relied upon historical data during a period

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[2] The Report estimates $689/kW in installed costs for an upstate peaking unit, while the current estimate is $654/kW (based on Levitan's estimate of $599/kW in 2004, adjusted for 3 percent annual inflation from 2004 to 2007).

[3] NYISO Services Tariff, §5.14.1(b), Sheet 157.

[4] The Report mischaracterizes DPS Staff's recommendation by indicating a suggested excess for NYCA of 920 MW, rather than 400 MW. It is inappropriate to add a NYCA excess to a NYC excess because NYC (and LI) are subsets of the statewide market. Thus, an excess in NYC or LI permits a deficit in "rest-of-state" capacity, while still meeting the NYCA requirement.

of substantial excess capacity, and failed to appropriately adjust for tight market conditions. In the last reset of the Demand Curve, DPS Staff estimated net energy revenues of $25/kW-year for the 7FA peaking unit in the Capital Zone. However, DPS Staff recommended using only one-half of this level (i.e., $12.50/kW-year), in lieu of an explicit excess capacity adjustment. In this case, where the Report proposes to explicitly model an excess capacity adjustment, there is no need to use such a conservative estimate of the net energy revenues. Thus, DPS Staff recommends increasing the statewide offset for net energy and ancillary service revenues to $25/kW-year. This would reduce the statewide reference price by approximately $16/kW-year.

Furthermore, the Report proposes an excessive inflation increase for the 2009/2010 and 2010/2011 Capability Years. In particular, the Report suggests an escalation rate of 7.8 percent based on the last two years of data for the Handy-Whitman Index. However, the last two years of data, which show large increases, is an inadequate data set to draw conclusions upon and disregards the other 30 plus years of data, as well as statements contained in the Department of Energy (DOE)/Energy Information Administration's (EIA) Annual Energy Outlook 2007.[5]

[5] The NYISO identified the EIA's data as a source in computing Appendix D of the Report.

As discussed below, a more realistic escalation rate would be 2.9 percent.

DISCUSSION

I. Average Excess Capacity Should Reflect The Size of a Typical Generation Addition

The Report assumes an average level of excess capacity of 2.8 percent for the NYCA, which corresponds to over 1100 MW (based on a statewide requirement of about 40,000 MW). As previously stated, the NYISO tariff requires that ICAP reference prices should be computed “under conditions in which the available capacity would equal or slightly exceed the minimum Installed Capacity Requirement.” While the tariff does not indicate that reference prices should be computed under conditions in which the available capacity would *never* be expected to be below the minimum Installed Capacity Margin, NERA’s assumption of a 2.8% average level of excess capacity attempts to ensure that outcome.

Further, the New York State Reliability Council (NYSRC) *requires* that the Installed Reserve Margin be calculated such that it is adequate to ensure that the probability, on average, of disconnection of firm load due to resource deficiencies is no greater than once in ten years. However, the Report assumes that generation levels will be maintained, on average, at 1100 MW in excess of that level.

To put this issue in context, it should be noted that recent capacity additions of new combined cycle facilities, such as those constructed by Astoria Energy, LLC and the New York Power Authority, have been in the 500 MW size range. Assuming a more-or-less constant average excess capacity of 1100 MW of ICAP would require that the excess installed reserve margin fluctuate between 850 MW and 1350 MW. Therefore, the Report's estimate of excess capacity is excessive.

To the extent the tariff allows the ICAP reference price to be computed under the assumption of excess capacity conditions, DPS Staff recommends that the level be based on the assumption that 500 MW facilities are constructed approximately every year to keep up with load growth, while maintaining sufficient installed capacity levels that are above the IRM. As such, an average excess of 250 MW would exist over time, which corresponds to about 0.63 percent. Rounding up the target level to 1 percent of the NYCA requirement, which corresponds to about 400 MW, should accommodate for any uncertainties.

For NYC and LI, the Report assumes an average level of excess capacity of 4%, which corresponds to about 400 MW in NYC and about 220 MW on LI. As previously discussed, the capacity of recent combined cycle additions has been in the 500 MW range, suggesting an average excess of 250 MW is needed to keep NYC's ICAP level from falling below its locational capacity requirement. DPS Staff supports the assumption of an average excess capacity level of no more than 3% (corresponding to about 300 MW) for NYC.

II. Net Energy/Ancillary Services Revenues Should Reflect Tight Capacity Conditions

The NYISO's tariff requires that estimates of net energy/ancillary services revenues reflect conditions near equilibrium, when capacity markets are relatively tight.[6] However, the Report estimated these revenues using historical prices from 5/1/2003 to 12/31/2006, which was a period of significant excess capacity in upstate NY and the entire northeast, as new gas-fired merchant combined-cycle plants entered service in response to the boom years of the late 1990s. As a result, historical energy and capacity prices in upstate NY during this period were generally too low to support investment in new gas-fired peakers.[7] While these were appropriate price signals, since there was no need for new upstate peakers, they do not provide a good basis for estimating what peakers would be expected to earn in a tight market.

The Report attempts to adjust its net energy revenues for the excess capacity through an econometric model. However, this adjustment is inherently flawed by assuming that there is a linear relationship between capacity levels and energy prices, despite the likelihood that the actual relationship is highly

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[6] The NYISO's tariff indicates that the NYISO shall assess "the likely projected annual Energy and Ancillary Services revenues…under conditions in which the available capacity *would equal or slightly exceed* the minimum Installed Capacity requirement." (emphasis added).

[7] See, Patton's 2006 State of the Market Report, p. 17, Figure 12.

non-linear, especially under tight capacity conditions that the tariff calls for. To illustrate, a reduction in excess capacity will drive demand up the supply curve. A typical supply curve has a "hockey stick" appearance, in which the curve tends to increase gradually until the upper end, where it jumps up steeply reflecting the high energy costs of peaking capacity. A peaking unit's energy revenues will tend to follow this "hockey stick" projection, whereby revenues slowly increase until they sharply rise as the market becomes tight (i.e., near equilibrium). Because the Report only covers a period with significant excess capacity in the statewide market, it fails to capture the sharp increase in net energy revenues as the market becomes tight.

DPS Staff recommends an offset of $25/kW-year. This is the estimate the New York Public Service Commission (NYPSC) supported during the last reset of the Demand Curve in 2005.[8] In lieu of an explicit excess capacity adjustment, in 2005 the NYPSC suggested its energy offset be cut in half to $12.50/kW-year. However, if the NYISO chooses to employ an explicit

[8] See, Docket No. ER05-428-000, New York Independent System Operator, Inc., Notice of Intervention and Comments of the New York Public Service Commission (filed January 28, 2005); see also, Affidavit of Mark Reeder in Docket No. ER05-428, March 21, 2005, presented at the FERC Technical Conference. The $25/kW-year estimate was based on three components: historical "actual" energy revenues from 2000 to 2003 adjusted for scarcity prices, totaling $18.49/kW-year; ancillary services, estimated at $0.67/kW-year; and an adder to represent the impact of a tighter statewide capacity market (compared to the period 2000-2003) of $6/kW-year.

excess capacity adjustment, DPS Staff supports the use of the full $25/kW-year net energy offset.

Additional support for this value is provided by comparing Capital Zone to downstate energy prices. When the upstate market is tight, the state, as a whole, is likely to be quite reliant upon downstate peaking capacity, and hence net energy revenues for an upstate peaker are likely to be closer to NYC net energy revenues for comparable plants (excluding real-time revenues due to ThunderStorm Alerts). As evidence, average on-peak energy prices by zone in 2006 can be compared to prices in 2000, which was during a time when upstate and regional markets were tighter (i.e., prior to the entry of new gas-fired combined cycle plants, especially in New England):

Average On-Peak[9] LBMPs by Zone

		Capital	NYC	LI
Summer 2000	Average LBMP	$73.58	$76.55	$74.75
	Ratio to NYC	96%	100%	98%
Summer 2006	Average LBMP	$75.08	$109.93	$136.42
	Ratio to NYC	68%	100%	124%

This data supports the conclusion that peak-period Capital Zone prices tend to reflect downstate prices when the

9 Summer On-Peak periods defined as June-August weekdays, 7am-11pm, excluding holidays.

statewide market is tight, since upstate load will be relying on downstate peakers.

NERA's spreadsheet provides information as to the impact of higher peak-period prices on the energy revenues of an upstate peaking unit. The spreadsheet provides day-ahead and real-time energy revenue estimates for a 7FA unit located in both the Capital region and NYC. The estimated day-ahead market energy revenues are approximately $16/kW-year higher in NYC than in the Capital region, according to NERA's model. However, as noted above, when the statewide capacity market is tight, peak-period prices are likely to be just about as high in the Capital region as downstate.[10] Thus, NERA's NYC revenue estimate provides a better proxy for what an upstate peaker would earn when the statewide market is tight. This suggests that the non-linear impact of a tight statewide capacity market can be approximated by applying a $16/kW-year adder to NERA's estimate of Capital Zone energy revenues.

Thus, the Report's estimate of Capital Zone net energy and ancillary service revenues of only $9.36/kW-year significantly understates the likely net revenues under equilibrium conditions. In a tight statewide market, peak-period Capital Zone energy prices are likely to be much closer

[10] An exception is ThunderStorm Alerts, which reduce transmission limits between upstate and downstate in the real-time market; this increases NYC prices but decreases Capital Zone prices. For this reason, the analysis only considers increased revenues in the day-ahead market.

to NYC energy prices than what was observed over the past few years of significant regional excess capacity. The consultant's model shows that, had upstate peakers received NYC energy prices, they would have earned over $25/kW-year; and to this amount Dr. Patton's adjustment of $2.05/kW-year was added, for a total of $27.41/kW-year. This substantial change reflects the non-linear impact of a tighter statewide capacity market.

Moreover, the NYPSC is promoting mandatory hourly pricing at the retail level (e.g., placing nearly 6,000 MW of large customers on default Day-Ahead Market prices). An increase in hourly pricing should lead to a flattening of the load shape, with more hours per year reflecting high scarcity prices. FERC agreed that "as NYPSC notes, increased use of real-time pricing at the retail level may flatten the load shape in the future."[11] This should increase the number of hours during which peakers can earn significant net energy revenues.[12]

[11] FERC Order Accepting ICAP Demand Curves, Docket ER05-428, April 21, 2005, p. 13.

[12] Affidavit of Mark Reeder, paragraphs 36-44, in Docket No. ER05-428, March 21, 2005. Mr. Reeder quotes from Eric Hirst and Stan Hadley: "…increasing the time-of-use elasticity flattens the load duration curve. …the flatter load duration curve leads to greater use of generators with high costs. This greater use permits them to recover more of their fixed costs from energy charges and, therefore, requires a smaller capacity payment for them to break even." (pages 41-42, Maintaining Generation Adequacy in a Restructuring U.S. Electric Industry; by Eric Hirst and Stan Hadley; October 1999; Oak Ridge National Laboratory; ORNL/CON-472).

DPS Staff strongly believes that the upstate net energy revenues should be increased significantly to better reflect conditions near equilibrium (i.e., tight upstate and regional markets) and the expected flattening of the load shape due to increased hourly pricing. Therefore, the Board should increase the estimate of net energy/ancillary services revenues for the Capital Zone to $25-kW-year.

III. The Escalation Rate Should Adequately Reflect The Underlying Data

The Report proposes an escalation rate of 7.8 percent, which was projected based upon the average rate of change in the deflated Handy-Whitman Index for power plant construction during the last two years. The NYISO provided Handy-Whitman data, as contained in a DOE/EIA report.[13] However, the NYISO's use of only two years of that data, which show large increases, results in an inadequate data set to draw conclusions upon, and a skewed projection that ignores the other 30 plus years of data, as well as conclusions reached in the DOE/EIA report.

The DOE/EIA report provides long-term trends in construction commodity costs and electric utility construction costs between 1973 and 2006, adjusted for general inflation. This data shows a range from a low of 94 in 2000, to a high of 118 in 1976 and 1977. Inexplicably, the Report projects that such costs will surpass the highest level they have ever been in

[13] See, http://www.eia.doe.gov/oiaf/aeo/index.html, Issues in Focus, pp.40-41.

33 years by 2008, and will keep rising in the future (i.e., 119 in 2008, 125 in 2009, and 132 in 2010). This is an unrealistic assumption given past data and the DOE/EIA's own forecasts that suggest otherwise.

A more realistic assumption should recognize that construction costs tend to track general inflation, with only temporary, limited deviations. Moreover, construction material costs closely coincide with electric utility construction. As the DOE/EIA has observed, "[b]ecause equipment and materials generally represent two-thirds to three-quarters of total power plant construction costs, it is not surprising that the trends are similar" (i.e., electric utility construction vs. construction materials). Although the two indices diverged in the early 2000s, "with electric power construction costs showing a flat to slightly increasing trend, while general construction costs continue to decline, [t]he difference coincides with a construction boom in the electric power sector from 2000 to 2004."[14] The DOE/EIA report goes on to state that, given current trends, where "new construction in the electric power sector is slowing down,… likely a response to the oversupply of available capacity than a response to higher commodity prices," one would expect the increase in construction material costs to also slow

[14] Id.

down.[15] This should decrease the upward pressure on the cost of construction materials.

Further, DOE/EIA "does not project significant increases in new generating capacity in the electric power sector until after 2015." While some may argue that New York will need additional capacity by 2011, the markets relied upon to project the escalation rate are national, if not global, and therefore the index should not be appreciably affected by whatever small amount of additions will be needed in New York. This should similarly decease upward pressure on electric power sector construction costs.

The long-term history of construction material costs illustrates that a significant escalation rate is not warranted. As DOE/EIA assumes, “for the purposes of long-term planning in the energy industries, costs will revert to the stable or slightly declining trend of the past 30 years."[16] A more reasonable escalation rate should consider these long-term trends of the Handy-Whitman Index. For example, the 33 year average annual growth rate for this Index is .2 percent. Adding the 2.7 percent inflation rate identified in the Report to this amount would result in an escalation rate of 2.9 percent.

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[15] Id. at 41.

[16] Id. at 36.

CONCLUSION

The Board should require the revisions discussed above to be made prior to filing the Report with the Federal Energy Regulatory Commission. These revisions will help ensure that the ICAP Demand Curves are just and reasonable over the three upcoming Capability Years.

Respectfully submitted,

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