August 29, 2007

Department of Public Service (DPS) Staff Comments on NERA's Demand Curve Reset Study

DPS Staff strongly supports the use of the LMS100 as the appropriate peaking technology for New York City (NYC) and Long Island (LI). Based on NERA's estimates, the LMS100 is the least costly source of new installed capacity for NYC and LI. By comparison, NERA has estimated the net cost of the older LM6000 to be at least 50% higher than the LMS100. Moreover, the LMS100 has been proposed as a market-based solution for NYC capacity in the 2007 CRPP, to enter service within the 2009-2011 time period. NERA expresses concern that the LMS100 equipment prices may increase in the near term, reflecting high demand and limited competition. However, this does not justify the use of NERA's much higher LM6000 estimates; a better approach would be to allow for some reasonable increase in the equipment cost of the LMS100. In addition, NERA relies on quoted prices which may not reflect the supplier's best offers; this could inflate NERA's estimated costs of the LMS100 as well as of the LM6000 and 7FA. Caution should be used when accepting and incorporating those quotes for purposes of the demand curve reset. Finally, using NERA's LM6000 estimate and delaying the introduction of the LMS100 until the next demand curve reset would impose a huge increase (about $50/kW-year) in the NYC reference price, likely followed by a huge decrease next time, imposing unnecessary costs and confusion on the NYC capacity market.

DPS has identified 3 areas of concern with NERA's Study: 1) the assumed average level of excess capacity (2.8% statewide, and 4% in NYC and LI); 2) the added adjustment for regulatory risk (20% chance of a 50% reduction in capacity revenues); and, 3) the estimates of net energy revenues, especially for rest-of-state (Capital zone).

1) Average Excess Capacity

The study assumes an average level of excess capacity of 2.8% in the statewide market, corresponding to over 1100 MW (based on a statewide requirement of about 40,000 MW). If capacity is placed into service such that it approaches, but does not drop below the required IRM, an average excess capacity level of 1100 MW would exist if a facility sized at 2200 MW were placed in service approximately every five years.[1] By comparison, new combined cycle facilities recently placed in service have been constructed in the 500 MW size range.[2] If we assume that 500 MW facilities are constructed, a new unit would have to be constructed almost every year to keep up with load growth. Under this assumption, an average excess of 250 MW would exist over time. Therefore, establishing a more-or-less constant excess of 1100 MW of installed capacity appears excessive and unsupported. DPS Staff supports an average level of excess

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1 The NYISO's 2007 Load & Capacity publication projects statewide load growth at somewhat over 400 MW per year through 2017. It would take approximately 5 years to deplete 2200 MW of excess at that rate.

2 For example, the facilities constructed by Astoria Energy, LLC and the New York Power Authority.

capacity of 1% (corresponding to about 400 MW) as a more reasonable amount based on current experience.

For NYC and LI, the study 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 installed capacity level from falling below its locational capacity requirement. An average level of excess capacity of 3% (corresponding to about 300 MW) is therefore more reasonable for NYC.

2) Adjustment For Regulatory Risk

This adjustment appears to be superfluous and unsupported because the study already accounts for risk via the return on equity and the average excess capacity assumptions. The only example given by NERA to support this adjustment is for "rate-supported long-term contracts that may be added even when there are surpluses or to create surpluses." (p. 62). There is no basis for this claim. The Comprehensive Reliability Planning Process limits regulatory backstop solutions to capacity needed to meet reliability needs, not to create surpluses. Nor has the Public Service Commission (PSC) supported long-term contracts solely to create surpluses. The PSC has supported renewable resources, primarily wind, for environmental and other reasons, although this has only had a small impact on capacity markets because wind has a low capacity factor (e.g. 3000 MW of upstate wind only counts for about 300 MW of capacity). As for additional risks due to regulatory interventions, it must be recognized that all markets are impacted by decisions involving regulatory and other governmental agencies. Moreover, while some of these interventions could lead to (temporary) reductions in capacity prices, others could lead to increases in capacity prices (for example, difficulties in siting new generation or transmission lines). The study provides no rational basis for its assumption that regulatory risks will all work in one direction. Therefore, this adjustment should be eliminated.

3) Net Energy Revenues

The NERA study estimated net energy revenues using an econometric model to forecast energy prices. The econometric analysis used historical prices from 5/1/2003 to 12/31/2006. However, this 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. The result is that historical energy prices in upstate NY during this period were generally below the running costs of gas-fired peakers. However, the estimates of net energy revenues are supposed to reflect conditions near equilibrium, when capacity markets are relatively tight.

Although NERA attempts to adjust for capacity levels by including capacity levels as independent variables in its econometric model, the model assumes a linear relationship between capacity levels and prices, despite the likelihood that the actual relationship is highly non-linear. In particular, when the upstate market is tight, upstate load is likely to be quite reliant upon downstate peaking capacity. Since downstate load needs downstate peaking capacity regardless, due to locational reliability requirements, it is likely more efficient for upstate loads to take advantage of the availability of downstate peaking units than to build additional peaking units upstate. Thus, under equilibrium conditions, upstate peak-period prices are likely to be closer to NYC peak-period prices, and hence net energy revenues are likely to be closer to NYC net energy revenues for comparable plants (excluding real-time revenues due to ThunderStorm Alerts). As evidence, we can compare the average on-peak energy prices by zone in 2006 to the prices in 2000, which was during a time when upstate and regional markets were tighter (prior to the entry of new gas-fired combined cycle plants, especially in New England):

Average On-Peak[3] 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%

Moreover, the PSC is promoting real-time pricing at the retail level (e.g., placing nearly 6,000 MW of large customers on default Day-Ahead Market prices). As discussed at the FERC Technical Conference in April 2005, an increase in real-time 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.”[4] This should increase the number of hours during which peakers can earn significant net energy revenues.[5]

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 real-time pricing.

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

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

5 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)