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MEMORANDUM

DATE:	January 9, 2007
TO:	John Charlton
FROM:	Mike Cadwalader
RE:	Assumptions for ICAP Demand Curve Study

During the December 21, 2006 meeting of the Installed Capacity Working Group (ICWG), the consultants that the NYISO has selected to perform the ICAP Demand Curve Study (Sargent & Lundy and NERA) presented the assumptions upon which they proposed to base that study. At that meeting, you asked for market participants to submit comments and questions regarding those assumptions. Accordingly, I am submitting these comments and questions regarding those assumptions on the behalf of my clients, consisting of LIPA, NYPA and the members of the Transmission Owners sector.

CONCEPTUAL APPROACH

Long-Run Equilibrium Net Cost of Entry

Initially, it is necessary to emphasize that the intent of the study must be to estimate the net cost of developing new peaking generation in the *long-run equilibrium*. Because this is a long-run estimate, temporary fluctuations in costs or financing assumptions should be ignored. So, for example, if generating equipment is currently very cheap because of a glut, the net cost of entry should not reflect that temporarily low price. Similarly, if generating equipment is currently very expensive due to unexpectedly strong demand coupled with limitations on the ability to meet that demand in the short run, the net cost of entry again should not reflect such transient factors.

Consequently, it would not be appropriate for labor costs to increase "if construction for the World Trade Center site is very active for the 2008-11 time period," as Sargent & Lundy suggested might be appropriate, because the study's intent is not to estimate the cost of developing a generator that incorporates transient factors specific to the 2008-11 time period. Similarly, it would not be appropriate to use financing assumptions that reflect transient market conditions, as some market participants have already begun to advocate. Financing assumptions should not be based on "what it would take to finance a generator today". Instead, they should reflect expectations of what would be necessary in the *long run*.

Similarly, the net cost of entry should reflect *equilibrium* conditions, which the Services Tariff defines as "conditions in which the available capacity would equal or slightly exceed the minimum Installed Capacity requirement…."[1] Accordingly (as the NERA presentation recognized), the margins on the sale of energy and ancillary services should reflect conditions in which that amount of capacity is present in the market.

Finally, since the purpose of the ICAP demand curve is to ensure that there will be sufficient incentives for the development of new generation when the ISO is at or near the minimum ICAP requirement, it would be inconsistent to assume when designing the demand curve that it has failed in that objective. This means that margins should not be calculated under the assumption that considerably more capacity than is required to meet the minimum ICAP requirement is in service, nor should financing assumptions reflect allegations that short payback periods are required due to concerns that extra-market actions will produce significant capacity surpluses. In short, the market cannot function correctly and provide the proper incentives for entry if it is designed under assumptions that implicitly assume that it will not provide the proper incentives for entry. Therefore, the consultants must resist pressures to determine the demand curve under the assumption that it will not succeed in providing market-based signals that induce entry when it is needed.

Information Needed to Evaluate Study Conclusions

Another factor that requires emphasis is the need for market participants to have sufficient information to permit an informed evaluation of the study conclusions. During the last ICAP demand curve study, for example, the TOs raised a number of questions about the components of many of the line items associated with the costs of generator development. Nevertheless details were never supplied regarding, for example, how shipment or balance of plant costs were calculated, which made it impossible to conduct a detailed review of the calculations of generating plant costs or challenge the results. Most of the data on generating plant cost that will be used in this study has not yet been presented to us. Of course, that is understandable at this stage of the project, but it will need to be presented eventually, and in enough detail to permit an informed review.

At the last ICWG meeting, market participants requested additional detail regarding how NERA's volatility model will estimate future prices. This is particularly important given that the historical database on which the model is based covers a period in which there has been a substantial surplus of installed capacity in the New York market, but the margins at the long-term equilibrium should reflect, at most, a small surplus. Market participants will need to have enough information regarding the use of the model to be confident that it is producing margins that are consistent with the long-term equilibrium. Similarly, market participants will need to understand the modifications that the ISO is making to reflect differences between past conditions and future conditions (e.g., to reflect new generation or transmission expansion), and how those will be accommodated while still estimating the margins that would be realized under long-term

[1] Services Tariff, Seventh Revised Sheet No. 157.

equilibrium conditions. Finally, in addition to reflecting changes in the physical characteristics of the power system, the consultants should also endeavor to incorporate any known significant market rule changes in their forecast of future prices, since any such changes would affect the degree to which past prices can be used to predict future prices.

GENERATOR COST AND REVENUE ISSUES

Generator Technology

The technology assumed for the base case properly uses a simple cycle generating technology, without including additional costs that would be needed to place the generator in a combined cycle configuration (either now or in the future). This is consistent with the directive contained in the Services Tariff for the study to estimate the net cost of entry for a peaking unit, which it defines as "the unit with technology that results in the lowest fixed costs and highest variable costs among all other units' technology that are economically viable."[2] Sensitivity cases can analyze whether incurring additional capital costs would increase margins on the sale of energy and ancillary services that are sufficient to offset the increases in capital costs and reduce the net cost of entry.

Generator Fuel

In this case, the consultants have proposed assuming that a new peaking unit would have dual fuel capability. Instead, for essentially the same reasons as described above for generator technology, the base case should assume a single-fuel generator, which would run on natural gas. (Fuel oil-only generators are unlikely to be permitted in New York City or Long Island due to emissions concerns, and gas availability constraints are not a significant impediment in the rest of the state.) Including dual fuel capability will entail additional capital costs, which is contrary to the Services Tariff's definition of the peaking unit that the study is supposed to be evaluating.

Of course, this assumes that the gas-only unit is economically viable. It is possible, particularly in New York City and Long Island, that developers could find that the benefits that result from the ability to switch between natural gas and fuel oil exceed the incremental capital costs associated with including dual fuel capability, in which case developers would opt to include dual fuel capability in new generators.[3] In that case, gas-only generators might not be economically viable. If they are not economically viable, the net cost of entry should not reflect the cost of developing gas-only peakers. Accordingly, the consultants should continue to evaluate the cost of developing

[2] Services Tariff, Seventh Revised Sheet No. 157.

[3] While, as cited in the Sargent & Lundy presentation, 60 of 169 simple cycle GTs have dual-fuel capability, most of the GTs with this capability are located in New York City and Long Island. Therefore, dual-fuel generators may not be economically viable outside New York City or Long Island.

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generators with dual fuel capability, but this analysis should be a sensitivity case, not the base case. Each analysis of the net cost of developing a dual-fuel generator should include the benefits that dual-fuel generators can realize when they can take advantage of changes in relative fuel prices and select the lower-cost fuel.

Minimum oil burn rules apply to certain dual-fuel generators under certain circumstances. These rules *increase* these generators' variable costs by requiring them to start burning a certain minimum amount of oil, even if the cost of oil is higher than the cost of gas. As a result, the variable cost that a dual-fuel generator incurs in those circumstances may currently be higher than the cost it would have incurred if it did not have dual fuel capability. Similarly, deficiencies in the procedures that the ISO currently uses to mitigate generators may, at certain times, preclude generators that are required to switch fuels from reflecting the cost of their fuel in its bid.

However, the ISO and market participants recognize these problems. The ISO is in the process of developing rules that would ensure that generators with dual fuel capability are not penalized for having that capability; those rules should be implemented in the near future. Enhancements to mitigation procedures may take longer but should be in place for the vast majority of the lifespan of any new generators that may be built in the next few years. To be consistent with the need to estimate the long-run equilibrium costs of building new capacity, these calculations should be conducted under the assumption that these issues have been resolved, so that there is no need for to adjust results to take these factors into account.

Location of ROS Generator

As discussed at the ICWG meeting, the consultants should evaluate several different ROS locations, since it is not clear which of those locations would have the lowest net cost of entry. At a minimum, those locations should include one lower Hudson Valley location, one location in the capital region, and one location in Western New York. Location-specific rates, such as the labor rates mentioned on page 3 of Sargent & Lundy's list of assumptions, should then reflect each location as closely as possible.[4]

Equipment Costs

There are substantial concerns about basing generator equipment costs on vendor quotes, since these quotes may not represent a vendor's best offer. These concerns are exacerbated if the vendor is aware of the purpose of the request for a quote, as this gives vendors an incentive to inflate their costs: Higher cost estimates would lead to a higher demand curve, which would provide incentives for the development of additional generating capacity, which would benefit vendors. Instead, reliance upon vendor quotes should be limited, and verified against costs incurred in actual projects whenever possible.

[4] Additionally, it is not clear what "cost to attract labor" means.

Ancillary Services Margins

In addition to the issues raised above, additional information on how NERA will calculate margins from providing ancillary services would be useful. Voltage support revenues, which were omitted from the last ICAP demand curve review, should be included in this calculation.

FINANCING ASSUMPTIONS

General

It would be helpful if page 5 of the table compiled by Sargent & Lundy included the sources used to derive the data appearing there (e.g., how property tax rates were estimated[5] and whether those rates vary locationally, how insurance costs were estimated, etc.). An explanation of the calculation of interest during construction would also be useful. Additionally, it is not clear what is meant when the table says that fixed O&M cost components are "included in the capacity charges," while variable O&M cost components are "included in the energy charges", as this speaks more to how these costs will be handled than to what these costs will be assumed to be. Each of those costs must be incurred by generators and will affect the net cost of entry for a given generator, so we would appreciate additional information regarding how those costs will be estimated.

Empire Zone Tax Rate Reductions

The taxation assumptions should reflect the likelihood that new facilities will receive Empire Zone tax rate reductions. Many existing generators already receive these credits, which can be substantial. Moreover, the willingness of state and local governments to agree to such reductions should not decrease, and might increase, as we approach the long-term equilibrium amount of capacity. Consequently, it would be appropriate to reflect these credits when determining the long-term equilibrium cost of entry.

Debt/Equity Ratio

The debt/equity ratio needs additional justification. If possible, it should be compared to debt/equity ratios that have actually been observed with development in the New York market. Information that some of the TOs have received indicates that the debt fraction for new development generally exceeds 50 percent. Of course, consistent with the need to estimate the net cost of entry in the long-term equilibrium, the debt/equity ratio needs to reflect what would be observed in the long-term equilibrium, which is not

[5] With respect to property tax rates: several of the TOs have noted substantial reductions in the assessed value of generators that they formerly owned but have now sold, so it will be important to ensure that the calculation of property taxes that the developer of a new generating unit would pay is not based on what TOs pay now or paid in the past.

necessarily the same ratio as has been observed in the market to date; but an assessment of that ratio is nevertheless necessary in order to inform an assessment of what this ratio would be in the long-term equilibrium.

ZERO-CROSSING POINT

Finally, the consultants should provide some description of the methodology they plan to employ when selecting a zero-crossing point. Unfortunately, during the last demand curve study, this issue was deferred, and then deferred more, and then deferred some more, and it was never properly addressed. It is important to ensure that history does not repeat itself.