COMMENTS OF THE MEMBERS OF THE TRANSMISSION OWNERS SECTOR, LIPA AND NYPA ON THE DRAFT VERSION OF THE ICAP DEMAND CURVES REPORT

I. Development and Operating Cost Estimates for Rest-of-State (ROS) Generators

The estimates of development costs for ROS generators that appear in the draft version of the installed capacity demand curves report ("Report") prepared by Levitan and Associates and distributed to members of the Installed Capacity Working Group are considerably higher than we expected, and we would appreciate additional information justifying these estimates. In particular:

Development Costs

Appendix C of the Report contains a detailed breakdown of development cost estimates for ROS 2xLM6000 and 2x7FA installations. In the category of equipment costs, while the costs listed for CTGs and SCRs/stacks seem reasonable, the costs attributed to the BOP (Balance of Plant) and shipment line items seem too high. As defined in the study, BOP costs are based on equipment cost from water treatment, gas compression & metering and electrical equipment. It is difficult to explain why these items should total $10 million for LM6000 and $29.9 million for a 7FA. As for shipment costs, the $2.5 million estimate for a 2xLM6000 installation might be reasonable for an in-city installation, but the same figure is used for ROS, where shipping requirements are less stringent. The $7 million cost for ROS 7FA shipment also seems excessive. The Report should contain additional justification and explanation of these line items.

Additionally, based on our engineering experience, the development costs required in addition to equipment at ROS sites seem to be far above the costs that we would expect to see. In our experience, these costs are generally somewhere between 60% and 100% of the equipment costs for a unit; but for a 2xLM6000 installation, Table 2 and Appendix C of the Report estimate total development costs of $93.2 million, of which only $41.5 million cover equipment, so non-equipment costs are ($93.2 – $41.5) / $41.5 = 125% of equipment costs, well in excess of the upper end of this range. Likewise, for a 2x7FA installation, Table 2 and Appendix C of the Report again estimate total development costs of $279.7 million, of which only $119.3 million cover equipment, so non-equipment costs are ($279.7 – $119.3) / $119.3 = 134% of equipment costs, even further above the upper end of this range. And as noted in the preceding paragraph, equipment costs are somewhat higher than we expected, so if those costs are lowered, then non-equipment costs would be an even higher percentage of equipment costs. Given the stark difference between these costs and the costs that we would expect to see, based on our experience in this area, we believe the Report should contain additional detail justifying its non-equipment cost estimates for ROS installations.

The estimate of development costs for the ROS LM6000 is particularly troubling because of the differences between the cost estimate appearing in the Report and the cost incurred by the Jamestown Board of Public Utilities (BPU) in developing an ROS LM6000. As the Report notes, using the Report's estimates for ROS LM6000 development costs, the Jamestown facility cost $791/kW, which was considerably less than the $971/kW estimated by the Levitan study. The Report notes a number of factors that might explain the difference. Instead of disqualifying the Jamestown facility, we believe that the Report should attempt to quantify the effect of these factors (as well as other factors which might have a countervailing effect, such as the reduction in economies of scale resulting from installing a single unit instead of paired LM6000s, or the fact that the Jamestown facility is capable of operating in combined cycle mode, so it is not merely a simple cycle unit). Levitan used a bottom-up approach that required Levitan to collect all the data it needed to write its Report. It should not be too difficult to collect a subset of this data and adjust the Jamestown data for the relevant differences. Furthermore, Jamestown should be used as a starting point since it reflects an actual project and not a theoretical project. Even though the Levitan Report concludes that "it is not possible to accurately compare Jamestown cost with LAI estimates due to these differences", there is some value in utilizing these actual costs. If this analysis indicates that the cost of the BPU's LM6000 was consistent with Levitan's analysis, once the adjustments have been performed, market participants can then assess whether they believe the adjustments are appropriate. If this analysis indicates that the cost of the BPU's LM6000 is not consistent with Levitan's estimate, Levitan may wish to modify its estimate, and market participants can voice their opinions on whether such modifications were appropriate or not.[1]

Finally, while they continue work on this issue, we note that PJM has recently published an initial estimate stating that a gas turbine would require $68/kW-year (in 2001 dollars) to recoup development and fixed operating costs, far below the corresponding estimates appearing in the Report for ROS simple cycle units.[2]

Site Development

One reason Levitan thought a translation of the Jamestown costs was inappropriate was that Jamestown put its unit at an existing site. While we recognize that there are arguments for using greenfield sites for such estimates, there are also arguments for using existing sites, as an existing site is a logical choice for placing new generation, and a significant amount of generation entry has occurred and may continue to occur at such locations. Consequently, while it is a defensible assumption, in making this assumption in its Report, Levitan has chosen an assumption that will tend to lead to increased ICAP costs and higher ICAP demand curves. This should be taken into consideration when assessing arguments put forward by others asserting that most or all of the assumptions appearing in the Report, while individually defensible, lead to lower costs and lower ICAP demand curves.

Property Taxes

Additionally, we note that the property tax rate used for ROS generation is higher than we would expect. The Report states that most ROS property tax rates fall between $8.75/kW-year and $18.70/kW-year, with a mean rate of $15.50/kW-year. Given the competition among financially strapped ROS communities wishing to induce new, environmentally friendly generators to contribute to their tax base, we would expect the tax rate that a new entrant would pay would be closer to the lower end of that range, but the Report assumes a property tax rate which translates to $13.68/kW-year for an ROS 2x7FA installation in 2005, roughly at the midpoint of that range (although below the mean tax rate), and which translates to $16.00/kW-year for an ROS 2xLM6000 installation in 2005, above both the midpoint of that range and the mean tax rate).

II. Energy and Ancillary Services Margins for ROS Generators

Similarly, estimates of energy and ancillary services margins for ROS generators appear to have been underestimated significantly, thereby increasing the Report's estimate of the net cost of entry for generation in the ROS region. There are several reasons for this.

Capacity Exceeding Minimum Requirements

These margins have been calculated using current market conditions, which reflect capacity in excess of minimum NYCA ICAP requirements, contradicting the demand curve methodology as specified in

---

[1] Additionally, one should note that multiplying the BPU's $791/kW estimate by the 96 MW net capacity of a 2xLM6000 installation yields total development costs of $75.9 million. If equipment costs are $41.5 million, as estimated by Levitan, that leaves $75.9 – $41.5 = $34.4 million in non-equipment costs, or 83% of the equipment costs associated with development. Therefore, the BPU's costs are much more consistent with our engineering experience than are the cost estimates for ROS development that currently appear in the Report, another reason why the estimates in the Report should be re-examined carefully.

[2] "Whitepaper on Future PJM Capacity Adequacy Construct", June 30, 2004, p. 12.

Section 5.5 of the ICAP Manual, which specifies that "Each ICAP Demand Curve is set based upon the localized, levelized cost of a gas turbine at the NYCA Minimum Installed Capacity Requirement or the Locational Minimum Installed Capacity Requirement, as applicable, and associated Energy and Ancillary Services revenues." In fact, as a table in Appendix D of the Report shows, the NYCA reserve margin assumed in the study described in the Report does not decrease to the minimum 118% of peak load level until 2012. For the years preceding 2012, the excess capacity available in the study will incorrectly depress ROS energy prices, and hence energy and ancillary services margins, that are available to new entrants. This in turn will improperly increase the ICAP payments that are required in order to induce entry.

Instead, the Report should calculate the ICAP payment that would be required to induce entry when the amount of ICAP provided is equal to the minimum ICAP requirement. This is because the reference price that is being determined by the Report will be used to set the level of the NYCA ICAP demand curve at a quantity of capacity that corresponds to the minimum ICAP requirement. If that point is calculated using energy and ancillary services margins that would be realized when there is excess capacity, then when capacity reaches the minimum required level, generators on average would receive energy and ancillary services payments that are consistent with that amount of capacity, plus ICAP payments that were calculated assuming energy and ancillary services payments under conditions of surplus. The result would exceed the net cost of entry (when the net cost of entry is calculated at the minimum ICAP requirement. As a result, more than the minimum required amount of ICAP would be developed, up to the point where the net cost of entry is equal to the ICAP payment determined using the demand curve. The intent of the ICAP demand curve is to ensure development of the minimum required amount of ICAP, not to ensure development of some unknown amount that is well in excess of the minimum required amount.[3] The most likely method to bring about this result would be to scale load in each year to ensure that the minimum NYCA and locational ICAP requirements are just met in each year of the study.

In its June 4, 2004 letter to the NYISO, PSC staff provided an excellent description of the market participants' understanding of how energy and ancillary service margins would be calculated. This letter supports the written instructions given to the all the potential consultants on December 19, 2003.

In addition, we note that if this method were used during a year in which the minimum ICAP requirements were not met, energy and ancillary services margins would be overestimated. Subtracting those margins from development costs would result in a price that falls short of the net cost of entry at the minimum ICAP requirement. Consequently, the amount of capacity that would be developed, given such a demand curve, would never be sufficient to meet minimum ICAP requirements. Therefore, not only is this technique inconsistent with the ICAP Manual and request for proposal sent out by the NYISO, it develops the wrong price and sets an inappropriate precedence for future consultant studies. Failure to model energy and ancillary service revenues at the minimum requirement level will invalidate the results of the analysis contained in the Report and any demand curves the NYISO recommends based on this analysis.

---

[3] A related point pertains to the claimed need for the demand curve to ensure procurement of some amount above the minimum requirement, in order to ensure that we do not fall below the minimum capacity requirement as a result of granularity issues, which might discourage relatively large generators from being developed until a shortfall relative to the requirement had developed that was roughly equal to their size. It should be pointed out that these generators are not captive to the New York market, so that if an additional 100 MW were needed to meet the New York ICAP requirement, a prospective 500 MW generator would not be forced into selling all of its capacity into New York, thereby forcing the price of ICAP below the net cost of entry. Instead, the remaining 400 MW could be sold into neighboring markets, many of which are in the process of re-evaluating their ICAP procurement procedures. Those evaluations are likely to result in increased compensation to ICAP providers, therefore making this option more likely.

Also, one should note that if the analysis is modified so that energy and ancillary services margins are calculated based on the assumption that the amount of ICAP available at each point in time during a new generator's life cycle is the minimum ICAP requirement, the relative costs of entry of the two generation technologies could change. While the net cost of entry for both ROS 7FAs and ROS LM6000s would decrease as a result of such a change in the analysis, its effect on these margins earned by a 2xLM6000 installation might exceed its effect on the margins earned by a 2x7FA installation by an amount sufficient to drive the net cost of entry for ROS LM6000s below the net cost of entry for ROS 7FAs.

Evaluation of Combined Cycle Units

The Report's ROS analysis concentrates on two possible generator technologies: 7FAs and LM6000s. In comments Mike Cadwalader submitted on our behalf before the beginning of the study (which he re-submitted after the May 27 ICAP WG meeting), Mike emphasized that it was necessary to ensure whether the less costly of these technologies would be part of the least-cost mix of ROS generation technologies. If the operating cost advantages of other technologies, such as combined cycle units, were significant enough to outweigh the additional development costs associated with those technologies, the net cost of developing other technologies might always be lower than the cost of developing a 7FA or an LM6000, in which case the cost of either a 7FA or an LM6000 overestimates the net cost of entry.

As far as we can tell, the Report does not contain any description of an assessment of whether an ROS combined cycle unit has a lower cost of entry than an ROS 7FA or LM6000. The only discussion of the cost of entry of combined cycle units seems to occur in the section that describes the entry model, but the entry model simply determines which generators will enter in order to ensure that ICAP requirements continue to be met over time. It does not address which generation technology will have the lower net cost as of the beginning of the study period, although it could probably be modified quite easily to address that question.

It appears that such a modification has, in fact, been performed, as one of the Levitan representatives at the August 2 ICAP WG meeting said that such an analysis indicated that the net cost of entry for ROS combined cycle units exceeded the net cost of entry for simple cycle units (although the difference was not large). However, so far as we can tell, no description of this analysis appears in the Report. The Report should include some description of the analysis that led to the conclusion that the net cost of entry for an ROS 7FA was below that of an ROS combined cycle unit. This explanation is particularly important since, given the relatively small development cost differences that appear in the Report ($831/kW for a 7FA simple cycle installation in ROS vs. $899/kW for an ROS combined cycle unit), we would expect the ROS combined cycle unit to be more economical if it runs very frequently, as its higher energy and ancillary services margins would quickly exceed the relatively small difference in development costs. Published data indicate that heat rate for a 7FA unit in combined cycle configuration is 6644 BTU/kWh and for an LM6000 unit in combined cycle configuration is 7271 BTU/kWh,[4] which should ensure frequent operation of such units. (In contrast, the same source states the heat rate for a 7FA unit in simple cycle configuration is 10,362 BTU/kWh, which would lead to considerably smaller energy and ancillary service margins.) In addition, reports issued by Dr. David Patton, the ISO's market advisor, have suggested that an ROS combined cycle unit might have a lower net cost of entry than a simple cycle unit.[5] The Report must be augmented to explain its conclusion that ROS combined cycle units are less economical than simple cycle units, since these conclusions are inconsistent with the results that market participants would legitimately expect, given the reasons discussed above.

---

[4] Source: 2003 GTW Handbook. Values have been expressed in terms of high heating value (HHV).

[5] See "2003 State of the Market Report," presented to the joint meeting of the NYISO Board of Directors and the NYISO Management Committee on April 20, 2004, particularly the discussion on slide 39 concerning the relative economics of ROS simple cycle and combined cycle units.

Finally, as we noted above, modifying the analysis so that energy and ancillary services margins are calculated based on the assumption that the amount of ICAP available at each point in time during a new generator's life cycle is the minimum ICAP requirement may change the relative costs of entry of different generation technologies. Consequently, even if the net cost of entry for ROS combined cycle units is higher than the net cost of entry for either ROS 7FAs, ROS LM6000s, or both, given the amounts of ICAP available at various points in time currently incorporated in the study, combined cycle units might nevertheless become the least expensive source of ROS capacity if modifications are made to ensure that there is no ICAP surplus in any of the study years. If combined cycle units are the least expensive sources of capacity, and would be developed in preference to simple cycle units, then a demand curve that is based on the net cost of developing simple cycle units will be too high, as it will overstate the net cost of entry.[6]

Gas Turbine Dispatch

While the stochastic model is clearly preferable to the deterministic model, in that it reflects the stochastic character of load and thereby more accurately represents the revenues that peaking facilities could expect to earn, we are concerned that it nevertheless underestimates the profits that peaking facilities would earn. The reason, if we correctly understand the stochastic case, is because the perturbations in load in each scenario are fully anticipated in the commitment of resources. Consequently, unusually hot days are anticipated in advance, and slow-starting resources may be committed to meet load on those days. The model therefore seems to preclude situations in which the commitment assumed relatively temperate conditions, but actual temperatures later proved to be higher than expected, and the ISO had no alternative but to start up peaking units, although it would have started slower-starting units if it had correctly anticipated the weather. Actual historic dispatch of gas turbines suggests that such events may account for a significant portion of the hours in which peakers operate, and may significantly increase the prices that they realize in the hours in which they operate. The analysis in the Report should either be modified in some manner to reflect these effects, or the Report should contain some discussion of why Levitan believes these effects to be immaterial.[7]

Entry Modeling

As described on p. 19 of the Report, Levitan determined whether simple cycle or combined cycle units would enter the market in each year in the time period covered by the analysis by comparing the net cost of entry for each type of unit and choosing the cheaper of the two. However, in Appendix D, Long-Term Generation Additions, an equal amount of new Peaking GTs (919 MW) and new Combined Cycle units

---

[6] Footnote 3 on page vi of the Report states that the ICAP Manual requires that the study estimate the net cost of entry for a peaking unit. We disagree, as we can only find references in the ICAP Manual and the tariff requiring the study to estimate the net cost of entry for a gas turbine. Consequently, we believe that this language permits—indeed, requires—the study to consider all gas turbine configurations that might be economical, including combined cycle configurations, in order to determine the source of capacity with the lowest net cost of entry.

[7] The consequences of a forced outage of a generator or a transmission line are similar to the consequences of unexpectedly high loads. We believe that, in response to questions asked in previous ICAP WG meetings, Levitan indicated that the commitment of generators does not presume knowledge of these forced outages in advance. If our belief is not correct, the analysis should also be modified to reflect these factors, unless Levitan believes them not to be material, in which case the Report should contain some discussion of why they are not considered material. On the other hand, if our belief is correct, then the Report, when it addresses the consequences of unexpectedly high loads for peaker margins, should note this. This also suggests a possible avenue for modifying the Report's analysis to reflect the effects on margins of unexpectedly high loads. If commitment can be performed assuming that one set of generators and transmission facilities is available, while the actual dispatch of generation assumes that a different set of generators and transmission facilities is available, reflecting forced outages that were not anticipated when the commitment was performed, it would seem possible to perform commitment assuming one level of load, and then to dispatch using a different level of load.

(916 MW) are added into ROS by 2022. If, contrary to p. 19, a pre-ordained mix of 50 percent simple cycle capacity and 50 percent combined cycle capacity was assumed to enter the market as needed, it would depress energy and ancillary services margins if the most economic mix of capacity was more heavily weighted towards peaking units. We are concerned that Figure 25, Gas Turbine Annual Capacity Factors, seems to be consistent with the latter approach. It shows a capacity factor for ROS GTs that consistently declines starting in 2017, keeping energy and ancillary services margins for peakers near zero; if entry is based on economics, we would expect peakers to stop entering when their margins are near zero, which would cause their capacity factors to rise, not fall, over time. If the analysis is based on the assumption that half of all entering capacity will be simple cycle units and half will be combined cycle units, the analysis should be revised, as it is unlikely that such an assumed mix would actually be observed in the ROS location. Such an assumption could fundamentally skew the mix of generation technologies available, relative to what would actually be expected to occur, thereby affecting the margins that different generator technologies would earn. Since the margins directly affect the net cost of entry for each technology, such an assumption would ultimately bias the determination of the net cost of entry for new capacity, since it is based on comparison of the net cost of entry associated with each technology.

Consistency with Forward Price Curves

Another area of concern regarding the energy and ancillary services margins used in the study results from the inconsistency between the prices noted in the Report and prices available from forward price curves. To the extent that forward price curves are available, the prices in the report seem to be significantly below forward price curves. For example, the Report suggests that forward prices in zones G, H, & I in the stochastic model would be at $40/MWh through 2010. However, at the close on August 3 in the OTC broker market, zone G was offered at $66.25 on peak and $47.25 off peak. For calendar year 2005, which will have 4,080 on peak hours and 4,680 off peak hours, the hourly price for the year is $56.10, so the prices forecasted by the Report in this instance differ significantly from the prices that market participants expect to observe.

When assessing the reasonableness of the prices forecasted in the Report, their implications should be considered. Consider the calendar year 2005. The Report's forecast of natural gas prices for that year runs close to the NYMEX Henry Hub 12-month strip, at $6.39 per Dth. Adding the $0.5825 per Dth basis that Levitan calculates for Iroquois Z2 to the Henry Hub price yields gas costs of $6.97 per Dth, (ignoring LDC charges), which is consistent with an implied heat rate of 5737 BTU/kWh,[8] indicating that only units with heat rates below 5737 BTU/kWh would earn margins in the average hour. This is very restrictive, particularly in light of the heat rates for new simple cycle and combined cycle units presented earlier, which exceed 5737 BTU/kWh. But if we use the actual bids and offers from the marketplace for calendar year 2005, the implied heat rate is 8046 BTU/kWh,[9] which would permit combined cycle units to earn a margin in the average hour.

As noted above, we believe that the prices used in the Report should actually be higher than forward prices, due to the fact that the analysis in the Report should be based on the energy and ancillary services prices that would be earned if the minimum required amount of ICAP were available, while forward prices will reflect the excess ICAP in the market for the near-term future. Given the assumptions currently used in the Report's analysis, the prices should be similar, and the lack of similarity suggests that there may be systematic factors that are depressing the prices calculated by Levitan. One such factor,

[8] The fuel price, expressed in $/MMBTU, multiplied by the unit heat rate, expressed in BTU/kWh, divided by 1000 is equal to the energy price in $/MWh. By solving this equation for the heat rate and substituting known energy and fuel prices, an implied heat rate can be derived. In this case, for an energy price of $40/MWh, the implied heat rate is $40 x 1000 / $6.9725 = 5737 BTU/kWh.

[9] For an energy price of $56.10/MWh, the implied heat rate is $56.10 x 1000 / $6.9725 = 8046 BTU/kWh.

pertaining to the treatment of unexpectedly high loads, was described above. There may be others; in particular, we are concerned that the some aspects of the MarketSym model that was used to produce the price estimates used in the Report may have produced lower prices than would have been produced by other models that might better represent the New York market, such as General Electric's MAPS model. We recommend that Levitan consider some method of modifying its results so that the prices its model produces (before modifying loads to eliminate ICAP surpluses) can be benchmarked against forward price curves, so that one can ascertain whether adjustments are likely to be needed to reflect for any systematic underestimate or overestimate of prices produced by the model, and if so, the likely magnitude of those adjustments.[10]

Location

The location assumed for ROS entrants appears to be zones G, H and I. (The Report explicitly states that energy and ancillary services margins have been calculated under this assumption; we presume that development cost estimates made the same assumption, although we do not believe this assumption was explicitly stated in the Report.) This may or may not be the ROS location at which the net cost of entry is lowest. While energy and ancillary services margins there will be higher there than at other ROS locations, development costs may be higher as well, and so the net cost of entry there may be higher than elsewhere. The net cost of entry in ROS should be calculated at the ROS location where the net cost of entry is lowest, since all ROS capacity is considered identical for the purposes of fulfilling the NYISO's ICAP requirements.

SCR Bids

Finally, SCR providers are assumed always to bid in at $500/MWh. However, bids for other ICAP providers increase over time, primarily as a result of inflation. As a result, SCR units are called upon twice as often in the later years of the study as in the earlier years. If SCR bids are also permitted to escalate over time so that they remain constant in real terms, this increased reliance on SCR providers will decrease, and energy and ancillary services margins will increase in hours in which SCR providers are called upon to reduce load.

III. ICAP Revenues for New Generators

The Report does not address issues associated with the use of unforced capacity (UCAP), as opposed to net capacity, as the metric for determining the amount of ICAP that each ICAP provider is credited with providing. As a result, it implicitly assumes that the use of UCAP instead of net capacity will not have any effect on the comparative economics of different generating plants. But this assumption is incorrect. In particular, newer facilities will likely experience fewer forced outages than older facilities, so the ratio of UCAP to net capacity for entrants will exceed the ratio of UCAP to net capacity for existing units. In other words, for each MW of net capacity, new entrants will receive a higher capacity payment than older units, due to the fact that they will generally be credited with a larger amount of UCAP for each MW of net capacity. The analysis should reflect the fact that the capacity payments that new generators will receive, expressed in terms of dollars per MW of net capacity, should exceed the average capacity payment per MW of net capacity that ICAP providers in general receive. This in turn would decrease the average capacity payment per MW of net capacity that is required in order to induce development of new capacity.

[10] In addition, the PJM whitepaper referenced above indicated that a combustion turbine had averaged $25/kW-yr. In energy and ancillary services revenues (we believe this actually refers to margins above variable cost) over the period, well above the margins forecasted in the study and used in the Report.

IV. Demand Curve Slope

The Report does not recommend a change in the "zero crossing point" for any of the ICAP demand curves (i.e., the points at which those curves intercept the x-axis), based on the notion that it does not discern any reason why a change is needed, although the Report's authors noted during the discussion of the report and in the Report's conclusions that they did not include in their analysis key assumptions such as an assessment of a supplier's portfolio by region or likely supply bids. This takes the wrong approach. It implicitly assumes that the current zero crossing points should be maintained unless there is significant evidence supporting the need for a change in those zero crossing points and then proceeds in conducting an analysis that does not reflect the relevant assumptions that are necessary for developing the supporting evidence. This assumption is not made in the tariff, in the ICAP manual, or in the scope of work document that was used to define the requirements for this study, so it should not be made here.

In supporting the NYISO's scope of work and in a preliminary discussion of the consultant's work, market participants were assured that this analysis would be included within the study. Contrary to the Report's conclusions, Figure 54 demonstrates that an ROS Demand Curve with a lower zero crossing point results in additional consumer savings for all likely levels of ICAP surplus. When the cost of entry at the reference level is adjusted for the reasons articulated in the sections above, the range of consumers' savings should increase significantly. Instead of merely asserting that there is, at this time, no reason to recommend a change in the zero crossing points, the study should determine which zero crossing points are best, without any predisposition to maintaining the status quo.

Neither this Report nor any previous NYISO analysis has documented a clear reliability or consumer benefit from purchases of ICAP well beyond the minimum requirement. The TOs have previously provided Levitan and the NYISO with a methodology for analyzing the consumer impact of alternative zero crossing points and request that Levitan be directed to conduct further analysis with the goal of recommending an appropriate zero crossing point. Demand curves that are likely to induce sufficient withdrawal by suppliers so as to cause the total ICAP cost for LSEs to increase should be avoided, as they would effectively require LSEs to pay more for less reliability, so this places an upper bound on the slope that should be assigned to these demand curves. However, demand curves with a slope at or near this upper bound ought to be considered, as demand curves with such a slope would not require consumers to pay more for less reliability, and also tend to minimize the inefficiency that results from using an ICAP demand curve that is "too flat"—i.e., which pays suppliers more for ICAP in excess of the minimum ICAP requirement than that ICAP is worth to end customers.

We recognize that the determination of the net cost of entry for new capacity will significantly affect the determination of the optimal zero crossing point, because the higher the net cost of entry, the steeper the demand curve for a given crossing point, and hence the greater the potential for the exercise of market power given that zero crossing point. It does not appear that the Report will come to a firm recommendation regarding the net cost of entry, preferring instead to present estimates of the net cost of entry for various scenarios. In that case, the Report should describe the best zero crossing points to use in each scenario, and the reasons why those zero crossing points are considered superior.