The following are joint comments from Con Edison, O&R, NYSEG, RG&E, NG and LIPA regarding the ICAP demand curve review. The comments are made in response to the preliminary results presented by Levitan & Associates in the April 22, 2004 ICAPWG meeting. Additional information that includes confidential locational modeling information may be sent to Levitan from each company individually.

<u>Selection of generator equipment for the Rest of State (RoS) market –</u>
The study needs to adopt a least net cost approach to the selection of equipment. The demand curve is designed to serve as a backstop for ICAP reliability, which supports the use of least net cost entry. Unfortunately, the preliminary Levitan results for the RoS market are based on GE LM6000 equipment, which is not the least costly new unit that can be put into service in New York. Specifically, Levitan estimated the GE LM6000 to have an installed equipment cost of $955/kW, while the cost of a GE Frame 7 (7FA) machine is only $413/kW, as indicated by the 2001 New England e-Acumen study Consequently, development of LM6000s in the ROS region will only occur if energy and ancillary services margins (less any differences in fixed operating costs between the LM6000 and the 7FA) are sufficient to offset this significant difference in installed cost. Current energy and ancillary services margins do not meet this test. As a result, if the estimates of energy and ancillary services margins that an LM6000 would earn in the RoS region that Levitan calculates are not sufficient to offset this difference in installed costs, the LM6000 machine would not be the least net cost equipment choice. (Additionally, in the event that those margins are high enough to justify the selection of the LM6000, it would be absolutely necessary to include these margins as an offset to the installed cost when calculating the net cost of entry.) In addition to reviewing the Frame 7 machine to determine least net cost, Levitan should also review the cost of capacity from other machines, such as the LM2500 GT's that has been contracted to serve as quick start capacity in southwest Connecticut, to assess whether the net cost of developing these generators might be lower than the net cost of developing LM6000s or 7FAs.

The least net cost of entry should also include locating the brown field site in a least cost location. For example, higher cost locations such as Hudson Valley would only be used if other cost savings or energy margins result in a lower total project cost than other NYS areas.

<u>Review 25% pre-tax equity return rate –</u>
Levitan is using a 25% pre-tax rate of return for the new entry. This high rate reflects the current "distressed" market and while for a distressed market this may be appropriate Levitan should consider whether this level is appropriate for the full life of the project. Levitan also needs to consider the effects of the demand curve. Since the demand curve provides generators with a more constant revenue stream that assures a significant level of cost recovery, for the period that the demand curve is in place the level of risk borne by generators is substantially reduced as compared to the time period prior to the demand curve, although this is offset by an offsetting removal of price volatility during shortages. Accordingly, the rate of return built into the demand curve rates should be reduced to reflect any reduced level of risk.

Modeling of Energy and Ancillary Services Markets as offsets to capacity revenue shortfalls –

Modeling of peaking GT operating hours and profits are often under estimated when using a computer simulation program. Energy and ancillary services revenues need to be accounted for to obtain a true picture of the economic conditions facing generators.

For example, David Patton's "**2003 State of the Market Report New York Electricity Markets"** shows that generator revenues from the combined electric markets are in the order of $180/kW-yr in the day ahead markets for peaking units with heat rates of 10,500 BTU/kWh in the NYC Vernon/Greenwood generation bus. When this figure is adjusted for the mild weather conditions in 2003, it can be argued that the revenues produced in the combined markets indicate that an increase in the demand curve price is not warranted. Accordingly, in setting the new demand curve rates, the Levitan study should take into account the combined revenues from the energy and ancillary services market. These combined revenues should be used as an offset to the capacity revenue shortfall projections.

Treatment of Generator Interconnection cost –

Interconnection costs should not be automatically recovered in the demand curve ICAP prices. Pursuant to Attachment S of the NYISO OATT and the joint NYISO/NYTO Order 2003 compliance filing, interconnection costs are divided between the transmission owner and the developers according to a FERC-approved formula. As such, developers do not pay for the entire cost of their interconnection. Further, if FERC does not accept the joint NYISO/NYTO compliance filing's interconnection cost allocation method, then interconnection costs will be allocated pursuant to the pro forma methods contained in Order 2003 and 2003A. Under those orders, interconnection costs are initially paid by the developers and then refunded back to them over five years, with interest, by the transmission provider. Accordingly, under Orders 2003 and 2003A, generators ultimately do not have any interconnection costs. It is imperative that the Third Year Demand Curve Study accurately reflects the amount of interconnection cost paid by generators and not assume that generators pay all of the interconnection costs.

Extension of permit and construction schedule –

Before Levitan extends the permit schedule by one year as suggested by one market participant Levitan should do more substantive research on what permit and construction schedules were under article X and assess the likelihood of whether a replacement for Article X is likely to increase or decrease historic schedules.