Independent Power Producers of New York, Inc. (IPPNY)

19 Dove Street, Suite 302
Albany, NY 12210
phone: 518-436-3749
fax: 518-436-0369
www.ippny.org
Gavin J. Donohue, *President & Chief Executive Officer*

October 8, 2010

Ms. Karen Antion
Chairwoman of the NYISO Board of Directors
c/o Mr. Stephen G. Whitley
President and CEO
New York Independent System Operator, Inc.
10 Krey Boulevard
Rensselaer, NY 12144

Re: Comments of Independent Power Producers of New York Inc. on Proposed NYISO Installed Capacity Demand Curves and Request for Oral Argument

Dear Chairwoman Antion:

In accordance with Sections 5.14.1.2.9 and 5.14.1.2.10 of the New York Independent System Operator, Inc.'s ("NYISO") Market Administration and Control Area Service Tariff and Section 5.6.6 of the NYISO's Installed Capacity Manual, enclosed please find an original and two copies of Independent Power Producers of New York, Inc.'s ("IPPNY") comments to the NYISO Board of Directors on the NYISO Staff's Proposed NYISO Installed Capacity Demand Curves for Capability Years 2011-2012, 2012-2013 and 2013-2014 issued on September 3, 2010 and revised on September 7, 2010.

Additionally, IPPNY respectfully requests the opportunity to engage in oral arguments before the NYISO Board of Directors' Market Performance Committee on the issues addressed in the enclosed submission and those of other market participants.

Very truly yours,

Christopher J. LaRoe

Managing Director
Independent Power Producers of New York

Enclosures

cc: Dave Lawrence (via e-mail; w/enc.)
Gloria Kavanah (via e-mail; w/enc.)
Diane Egan (via e-mail; w/enc.)
Will Dong (via e-mail; w/enc.)

COMMENTS OF INDEPENDENT POWER PRODUCERS OF NEW YORK, INC. ON PROPOSED NYISO INSTALLED CAPACITY DEMAND CURVES

Independent Power Producers of New York, Inc. ("IPPNY")[1] hereby tenders its comments to the NYISO Board of Directors ("Board") on the NYISO Staff's Proposed NYISO Installed Capacity ("ICAP") Demand Curves for Capability Years 2011-2012, 2012-2013 and 2013-2014 issued on September 3, 2010 and revised on September 7, 2010 ("NYISO Proposal").[2] In addition, IPPNY respectfully requests that it be given the opportunity to present its arguments relating to the NYISO Proposal before the NYISO Board of Directors' Market Performance Committee at the October 18th oral argument session. The NYISO Proposal adopted many of the recommendations included in the September 3, 2010 (also revised September 7, 2010) *Independent Study to Establish Parameters of the ICAP Demand Curve for the New York Independent System Operator* prepared by NERA Economic Consulting ("NERA") with assistance from Sargent & Lundy (S&L) (the "NERA Report"). At the outset, IPPNY views the NERA Report as generally a very professional effort to address and balance the myriad of interdependent and interrelated factors and assumptions that must be accounted for to determine the net cost of new entry ("Net CONE") of the proxy peaking unit(s) and the other parameters used to establish the New York City ("NYC"), Long Island ("LI") and New York Control Area ("NYCA") ICAP Demand Curves, as required by the NYISO's Services Tariff. IPPNY respectfully submits the following comments pertaining to positions taken by NYISO Staff regarding deliverability costs, property taxes, excess capacity, shape and slope of the curves, escalation factors, and the choice of the proxy unit. Additionally, IPPNY also disagrees with a NERA assumption (accepted by NYISO Staff) pertaining to the gas premiums faced by generators in the real-time market.

I. THE NYISO STAFF'S DECISION TO EXCLUDE DELIVERABILITY-RELATED COSTS FROM THE NET CONE CALCULATION IS INCONSISTENT WITH THE SERVICES TARIFF AND WILL NOT PROVIDE ADEQUATE COST RECOVERY TO SUPPORT NEW ENTRY

At the request of NYISO Staff, the NERA Report provides Demand Curve Values at the Reference Point for a NYCA Frame 7FA unit both with and without intra-zonal deliverability costs. The Net CONE for the NYCA Curve excluding deliverability costs is $95.03/kW-year; the Net CONE with deliverability costs is $121.98/kW-year. Although, also at the request of the NYISO Staff, NERA did not take a position on whether such costs should be included in the Net CONE calculation, the NERA Report noted correctly, "In order to participate in the capacity

[1] IPPNY is a not-for-profit trade association representing nearly 100 companies involved in the development and operation of electric generation facilities and the marketing and sale of electric power in New York.

[2] IPPNY is acting through its members on the New York Independent System Operator ("NYISO") Management Committee ("MC"). IPPNY submits its comments pursuant to Section 5.6.6 of the NYISO Installed Capacity Manual and Section 5.14.1(b)(x) and (ix) of the NYISO's Market Administration and Control Area Services Tariff ("Services Tariff"). Pursuant to Section 5.14.1(b)(x), IPPNY respectfully requests the opportunity for oral argument on this matter.

market a unit must be deliverable to all zones in the Capacity Region as defined in NYISO Services Tariff Attachment S (Zone J for New York City, Zone K for Long Island and all Zones other than J and K collectively as a single region for Rest of State). Currently new units north and west of UPNY/SENY could not deliver to Zones G to I and hence could not participate in the capacity market for ROS without obtaining deliverability. The NYISO has determined that the cost of deliverability is an investment of $178 per kW." (NERA Report, p.72)

Despite the fact that the tariff requires a capacity provider to be fully deliverable throughout its capacity zone (as fully acknowledged by NYISO Staff) in order to be eligible to sell capacity, NYISO Staff maintains its position that any System Deliverability Upgrade (SDU) costs associated with being deliverable should not be included in the proxy unit's Net CONE. Such a position is counter to the tariff language pertaining to the setting of the Demand Curve, which indicates that the Demand Curve must include all costs that a capacity supplier would incur to sell and provide capacity in a reliable manner. As stated in Section 5.14.1(b) of the NYISO's Services Tariff, "The periodic review shall assess: (i) the current localized levelized embedded cost of a peaking unit in each NYCA Locality and the Rest of State to meet minimum capacity requirements." Deliverability costs are, by definition, a form of system upgrade costs. Thus, just as all other system upgrade costs for the hypothetical proxy unit have long been included in the Net CONE calculations, these, too, also must be included. Failing to include these costs is a violation of the NYISO tariff.

If the Demand Curve is set without incorporating these costs, the revenues that the Demand Curve will provide will not be sufficient to induce new entry of a peaking unit anywhere in the Upstate region, and thus, will not ensure that the NYISO can meet its reliability requirements. The NYISO is recommending $89.79/kW-yr as the value for the Net CONE. However, including deliverability costs and accepting the remainder of the NYISO recommended demand curve assumptions (for the sake of argument) results in a Net CONE of $115.44/kW-year – a difference of $25.65/kW-year between NYISO's recommended Net CONE and the Net CONE with deliverability in the Rest of State region. Clearly, the difference between projected net CONE with deliverability costs and without is very significant, yet the NYISO Staff fails to identify any other revenue source for this "missing money." Now that deliverability requirements and the associated cost allocation rules have been incorporated into the NYISO's tariff, ignoring deliverability costs in setting the Demand Curves would frustrate the fundamental purpose of the Demand Curves to provide the necessary signal to developers to build new resources in time to meet the State's reliability needs. Moreover, if the Net CONE does not support entry of a unit that must incorporate deliverability costs, then, at equilibrium conditions, such a unit will not be able to recover its costs and will not be built; building a unit without required deliverability upgrades is not economically viable and will not satisfy the tariff obligation to "meet minimum capacity requirements" because a non-deliverable unit would make no contribution to meeting reliability needs. By definition, it would not be eligible to participate in the capacity market.

It appears that a Lower Hudson Value ("LHV") zone proxy unit would not have deliverability costs associated with the UPNY/SENY interface. However, the Net CONE for that proxy unit would be higher because environmental regulations require a different type of GT to be used as the proxy unit in this area. Using the NYISO's recommendations for the NYCA demand curve, replacing the Frame 7FA proxy unit (which could not be sited in the LHV) with an LMS100 (which could), and extending the demand curve to a zero point at 15% beyond the minimum requirement, results in a Net CONE of $129.22/kW-year. Thus the LHV unit's Net CONE is higher than the cost of a proxy unit in the Capital Zone, even with the inclusion of deliverability costs in the Capital Zone proxy unit's cost. Consequently, a LHV proxy unit also is not economically viable utilizing the NYISO Proposal's current reference prices.

The NYISO Proposal mistakenly relies upon the potential future creation of new capacity zones at some future point as an excuse to avoid setting the correct price signals now. The NYISO states that it "is committed to pursuing the development of new Capacity Zones with stakeholders as a separate activity from this Demand Curve review process."[3] Unfortunately, this statement simply ignores that transmission bottlenecks exist today and would be encountered by the recommended proxy unit located in the Capital Zone. Although new capacity zones may address these conditions (IPPNY expects its members will address the new capacity zone proposal when it is filed at FERC), the FERC issued a notice earlier this week granting the NYISO a limited extension of time to file the criteria to create new zones.[4]

Market Participants have long been on notice that new capacity zones may be created. Thus, if and when a new capacity zone is created, Demand Curves can be adjusted at that time to take the new zone into account. The system as it stands today does not, however, contain a Lower Hudson Valley Zone; the Demand Curves must be based on the facts that are now at hand. Thus, to comply with the requirements of its tariffs, the NYISO's options are limited to determining Net CONE based on a proxy unit above the UPNY-SENY interface with deliverability costs or based on a proxy unit in the Lower Hudson Valley, which does not appear to have deliverability costs.

One last point must be addressed in this regard. In an attempt to justify evading these costs, some parties have made theoretical arguments regarding what system conditions may look like under near-equilibrium conditions. Specifically, during working group meetings, some market participants have alleged that retirements would drive the system to these near equilibrium conditions, and, therefore, CRIS rights would become available to new entrants, eliminating the need for transmission upgrades. As reflected in the presentation made by Mark Younger at the 7/23/10 ICAP WG meeting, attached hereto as Appendix I, this argument is flawed in several critical respects. First, the factors that could drive the system to near-equilibrium conditions (load increase/shifting, changes in capacity resource quantity/location, etc.) are unpredictable and cannot be assumed to occur in a manner that would facilitate a new resource being sited in the Capital Zone without incurring substantial system deliverability upgrade costs. In fact, NYISO Staff has stated publicly during ICAP Working Group discussions that it believes it is highly unlikely that future circumstances would result in a system configuration alleviating the need for system upgrades for new capacity providers in the Capital Zone. If anything, the more likely result is to reach approximate load/capacity equilibrium via future load growth downstate in the areas where we have seen load growth in the past.[5] Second,

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[3] NYISO Proposal, Pg. 8.

[4] See FERC Docket ER04-449-018, New York Independent System Operator, Inc., et al., "Notice of Extension of Time" (dated October 4, 2010) (granting NYISO a limited, three month extension to and including January 4, 2011 for NYISO to file criteria).

[5] As reflected in past load growth analyses, the area of most substantial load growth in New York State has been Southeastern New York, i.e., the area south and east of the Leeds-Pleasant Valley constraint.

the Demand Curves have never assumed, and NERA does not assume now, that retirements would reduce the cost of System Upgrade Facilities. Even if rights were to become available from retiring units, such rights would not be conferred to a new entrant for free. There is no reasonable justification to treat System Deliverability Upgrades and System Upgrade Facilities differently. Without deliverability costs, Net CONE on the Demand Curve will not be sufficient to support new entry when needed to maintain reliability anywhere in the ROS region. This means that the proxy unit will not be viable and that the NYISO, if it proceeds as proposed, will not have met the tariff specified requirements associated with developing the costs for the ROS proxy unit.

II. IN-CITY PROPERTY TAX ABATEMENT IS NOT AVAILABLE TO NEW GENERATION PROJECTS AS OF RIGHT AND MUST NOT BE INCORPORATED INTO NYC PROXY UNIT COST CALCULATION

The NYISO Staff instructed NERA to calculate Net CONE for a NYC LMS 100 unit with and without property tax abatement. NERA estimated a Net CONE of $184.99/kW-yr with assumed abatement and $262.98/kW-yr without abatement. NERA then summarized the In-City property tax issue, “We model the with tax abatement scenario using the policy recently adopted by the New York City Economic Development Corporation (EDC) which indicates an intent to provide 11 years of zero property tax, and full property tax at year 12. This scenario and the no abatement scenario use the current effective rate of 4.69% of plant value. The EDC policy statement appears to indicate an inclination to provide the above-described abatement to the peaking unit that will be used in the Demand Curve reset, but does not provide the right to an abatement.”

Based on the aforementioned EDC policy, the NYISO Proposal assumes full property tax abatement for the proxy unit and proposes an In-City reference price of $153.52/kW-yr. Including full property taxes along with the remainder of the NYISO Proposal results in a Net CONE of 214.98/kW-year. The differential in revenues resulting from underestimating the cost of property taxes for a generator is extremely significant. Calculating Net CONE assuming tax abatement that is not as of right puts the NYC Demand Curve at risk of sending substantially insufficient price signals In-City to the tune of more than $60/kW year (i.e., insufficient by almost 30%). Such risk is unacceptable, particularly given the fact that historically New York City has been one of the main areas where reliability needs have been identified and where recent load growth has been strongest.

Discretionary tax abatement programs are just that, discretionary, meaning there is significant risk that the entity in charge of granting such abatements may choose to deny a request for abatement either in its entirety or otherwise limit it. This is true for the Third Amended and Restated Uniform Tax Exemption Policy (the Policy) recently approved by the Board of Directors of the New York City Industrial Development Authority (NYCIDA). Given the discretionary nature of all New York City programs, NYISO Staff’s Proposal to assume 100% tax abatement for the NYC proxy unit Net CONE violates the NYISO’s tariff. The Services Tariff requires the NYISO to “assess: (i) the current localized levelized embedded cost of a peaking unit …” (5.14.1.2). During the last reset process, the Industrial and Commercial

Incentive Program (ICIP) included provisions that granted new generation projects an as-of-right exemption from NYC real property taxes for eleven years, phasing out such exemption at 20% per year through year sixteen. Thus, full property tax abatement was properly included as an assumption in that study -- at least, when it was made. However, here, where the program in question is indisputably discretionary in nature, finding that full property tax abatement can be presumed in this reset process is fundamentally flawed for a number of reasons.

Notably, the Policy defines a "PlaNYC Energy Program Project" as a generation addition which resembles the choice of Peaking Unit to be used for CONE. Unlike ICIP, however, the Policy does not automatically grant a property tax exemption to all new generation projects. Instead, it grants the IDA the right to grant partial or full tax exemptions to projects which meet both objective and subjective criteria. IPPNY acknowledges that the objective criteria resemble the physical and operating characteristics of a GE LMS100, which is the presumed Peaking Unit for the NYC Curve for the 2011-2014 reset period. Were the objective criteria the only criteria required to be met, it may have been appropriate to make this full abatement assumption. However, that is not the case.

The subjective criteria instead provide the IDA with substantial flexibility to make determinations as it chooses -- including determinations to deny property tax abatements in whole or in part. For example, the subjective criteria include the requirement that "the proposed Peaking Unit will satisfy either (aa) a future reliability need as identified by any one of NYISO, the transmission owner, or the City or (bb) an environmental need identified by the City." There is, however, no definition as to how such reliability or environmental needs would be "identified" by NYC.

Likewise, requirement (aa) could be read to eliminate merchant entry as a candidate for exemptions. That is, only a project identified to satisfy a future reliability need, not one sponsored by an entrant on a merchant basis, may be argued to be eligible to qualify. Similarly, requirement (bb) is completely amorphous, subjective and not subject to question or independent analysis. Lastly, it must be noted that the very entity that would be deprived of property tax revenue (NYC) has exclusive authority to determine whether an exemption would be granted.

For all of the aforementioned reasons, the NYISO Staff recommended Net CONE for the NYC proxy unit and the associated NYC Demand Curve that it will produce do not represent "the current localized levelized embedded cost of a peaking unit." The current cost of a peaking unit includes property taxes. NYISO and the representative for NYC have both admitted, without qualification, that the Policy is not an as-of-right exemption for new entry of a peaking unit.

Neither the NYISO Staff nor NYC has proffered any evidence that the Policy has been utilized. Nor have they offered details definitively demonstrating how the subjective criteria outlined above would be applied or even if the property tax exemption would be granted if all the vague criteria were met. A purely discretionary program that has never been utilized, is not based on objective criteria – in fact, is imbued with an inherent conflict of interest – cannot be construed as an assured tax exemption. Finding otherwise is fundamentally counter to the requirements of the tariff, common sense, and fails to assure the reliability of the electric system. Failing to include the property taxes in the Demand Curve will put a pall on potential new resources in the City. The process to receive potential property tax exemptions that was described by the City would require the generator to spend millions of dollars in development costs before finding out whether it would receive the property tax exemptions that would be necessary to make the project economic. This would make investing in new generation in NYC significantly riskier. The NERA study did not otherwise include this additional risk factor. Indeed, if anything, as established in more detail below, the risk factors that have been included in the NYC Curve are already deficient standing alone before this factor is taken into consideration.

Calculating Demand Curves without assuming tax abatements is consistent with the decision in the last two Demand Curve Reset processes to not include potential property tax relief in the determination of the NYCA Demand Curve due to the uncertainty surrounding whether new combustion turbine generators would qualify for such tax abatement. There is no reasonable justification to treat potential property tax abatement differently in New York City than in the NYCA -- indeed, given the past and likely future reliability needs in New York City, the NYC Demand Curve assumptions should be more conservative. In addition, rejecting the NYISO Staff's recommendation to assume property tax abatements would also be consistent with the determination that was made during the last reset process to include dual fuel capability as a component of the capital costs for the NYC proxy unit because there was no assurance that units would otherwise be able to negotiate and arrange for special, discretionary site specific exemptions from Con Edison under its gas tariffs. As a result, the past Demand Curve Reset Final Report expressly found, "Given the possibility that a new peaking unit in New York City may be required to have [dual fuel] capability, dual fuel capability has been assumed for Zone J."

The NYISO staff recommendation states that actual experience with abatement under the new program will be used to guide future abatement assumptions. Given this statement, clearly the NYISO accepts that such real life experience would be an appropriate basis for making future assumptions. As we do not yet have any empirical evidence on which to rely, there is nothing to suggest that a 100% assumption on abatement is reasonable or defensible. As such, the NYISO's proposal cannot be viewed as reasoned decision making. There is no evidence to support a position of such extreme optimism particularly where, as here, the consequences of getting it wrong are that the cost of entry will be massively understated and will not come even remotely close to being sufficient to support new entry to meet reliability requirements when needed in an area of the State that previously has exhibited substantial reliability needs.

Concerns about "double-dipping" (not having abatement built into the curve and then having a new facility secure additional abatement) are unwarranted. Since the newly created program, like any other NYC program, is discretionary, and, considering that New York City continues to be an active participant in the Demand Curve reset process, NYCIDA is well aware of the assumptions that are built into the NYC Demand Curves. Thus, NYCIDA authoritatively would be able to point to FERC orders including such costs as sufficient support to deny abatement to a requesting generator. Discretion cuts both ways – on the one hand, it can protect against "double-dipping" where warranted -- which here, as we demonstrate, it is not -- yet, on the other hand, it also has the potential to result in substantial revenue shortfalls if the NYISO does not build the appropriate costs in its Demand Curves. The NYISO must come down on the side of ensuring costs are recovered in its Demand Curves and reliability is assured. This requires including the full potential cost of property taxes when setting the demand curves.

III. EXCESS CAPACITY ASSUMPTIONS

A. The CONE Was Calculated Correctly

The NERA Report and the NYISO Proposal both recognize that the assumption used for the amount of Installed Capacity relative to the annual Locational and NYCA Minimum Installed Capacity Requirement will impact the level of Energy and Ancillary Services revenues received by the new peaking unit. For the three-year period covered by this Demand Curve update, the NYISO recommends using a capacity level of 100.5 percent of the target Installed Capacity level for computing Energy and Ancillary Services revenues. IPPNY supports this recommendation and agrees with the NYISO that "this level comports with the Services Tariff, which states that Energy and ancillary Services are to be determined 'under conditions in which the available capacity would equal or slightly exceed the minimum Installed Capacity requirement'."[6]

Likewise, NERA has sought to calculate the CONE for the proxy unit for each Demand Curve in a manner that also takes into account the excess capacity risks that merchant facilities face in the market as a component of the calculation. On page 10 of the report, NERA states, "The model recognizes that the NYISO has in place planning and response procedures to prevent capacity from falling short. Hence, over time, there should be a bias toward surplus capacity conditions. If there is expected to be surplus capacity, the Demand Curve should be adjusted to reflect the fact that over time the expected clearing price would be below the target reserve point. Absent such an adjustment, the Demand Curve would not produce adequate expected revenues to recover cost and would not induce the proper level of investment. The model we have developed to set the Demand Curve accounts for these factors." IPPNY concurs with the premise that the risk of excess capacity on the system must be taken into consideration. The fact that steps will be taken to prevent the State from falling below the Minimum Requirement means that there will never be shortfall prices that, on average, offset surplus prices. Thus, unless this factor is addressed, the Net CONE, by definition, will be set too low, and thus, will not produce market outcomes (i.e., new entry) that are sustainable over the long term.

NERA's approach is both correct and necessary for a number of reasons. First, the lumpiness of capacity additions alone would will result in excess capacity even if capacity is only added once the Minimum Requirement is reached. Second, our history has demonstrated that New York State will never get to that point. Policy makers have not previously permitted reliability to be jeopardized by allowing a shortfall or near-shortfall of capacity below the Minimum Requirement. Nor is there any reason to presume a different approach in the future. In fact, the NYISO now has planning tools that were not yet part of its tariffs when reliability needs were forecasted in the early years of NYISO operations thus making it more -- not less -- likely that this approach will be continued. Specifically, the Comprehensive System Planning Process (CSPP) established by the NYISO goes to great lengths to ensure no shortage will occur. For example, under the CSPP, the NYISO, inter alia, has the authority to order that back stop solutions be submitted to respond to future projected reliability needs and, in the face of a more immediate reliability issue, can pursue gap solutions.

[6] Services Tariff Section 5.14.1.2.

Failing to reflect the bias of the electric system to maintain excess capacity beyond the Minimum Requirement would prevent the demand curves from achieving their intended purpose. It would instead ensure that, on average, revenues will be insufficient to support new entry, even when the system approaches the Minimum Requirement. NERA's proposed approach is critical to account for the market risk faced by developers concerning the high likelihood of excess capacity remaining on the system and the potential that market rule changes and/or intrusions in the market will artificially depress clearing prices. If an explicit risk component were not incorporated into the model, the risk premium required to provide adequate revenues for new generation and needed existing units would have to be incorporated via other changes to the model, such as increases to the cost of capital and changes to the capital structure.

For all of these reasons, IPPNY strongly suggests that the Board retain the approach to calculating the Reference Value developed by NERA and supported by NYISO staff – though the actual level of risk assumed for the reset period is insufficient as discussed at length below. Once again, it must be remembered that there are many interdependent variables that are involved in the CONE determination and in the structure of the demand curves, including capital structure, cost of debt and equity, amortization period, and the slope of the demand curves. One cannot alter or eliminate one assumption without making correlated changes to other parameters. IPPNY believes the overall approach developed by NERA and reflected in the NYISO Proposal, with extensive input from all market participants, is a rational and comprehensive package that should not be altered in piecemeal fashion.

B. The NYISO Has Offered No Justification for Diminishing the Consultants' Assumed Levels of Excess Capacity

As stated above, IPPNY agrees with the NYISO that the existing reliability processes in New York State make it extremely unlikely that the levels of capacity will be permitted to drop below the minimum requirement. In the NERA Report, the levels of excess were recommended based upon an assumption that the market will be long, on average, an amount equivalent to 1.5 times the size of the proxy unit. This resulted in the following levels of excess: NYCA average excess of 1.5%, NYC average excess of 3.0%, and LI average excess of 6.0%.[7] However, in the NYISO Proposal, those levels of excess were arbitrarily ratcheted down to an assumption that the market excess would average only one-half the size of the proxy unit, with the NYISO now supporting NYCA at 1% excess, or 101% of the Installed Reserve Margin; NYC at 1.1% excess, and Long Island at 2.1% excess.[8]

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[7] In the Report, NERA notes the fact that the NYISO Board declined to include some of the risk factors that it had identified as part of the 2007 demand curve reset process. While NERA continues to find that regulatory risks are plausible, it nonetheless declines to adopt them here focusing on the fact that the Demand Curves have not been artificially suppressed by arbitrary intervention over the past seven years. (See Report at 71-72.) IPPNY would note that there has been some intervention in the markets (e.g., the NYPA RFPs in New York City and the LIPA RFPs on Long Island) that has prevented the markets from falling to the Minimum Requirement. In addition, given the statements made by policymakers in public documents (e.g. PlanNYC), there is no reason to believe that such intervention will cease in the future.

[8] The NYISO also assumed that the average excess would be no less than 1 percent even if one-half the proxy unit was less than 1 percent.

NYISO Staff has not provided any justification for its assumption that there will be substantially lower levels of excess capacity in the market for the next three years than the 101.5% for NYCA and 104% for NYC and Long Island that was recommended by the Board and approved by FERC in the last reset process. In fact, NYISO Staff has changed its own view on expected levels of capacity just within this reset process, alone having recommended in its August draft recommendation levels of excess capacity for NYC at 2% excess and Long Island at 104.67% excess. Not only has NYISO not explained what has changed in the market to justify lowering the excess capacity assumptions from the previous reset process, it has not justified the changes from its own August recommendations to the ones that it then issued in September.

The result of the NYISO Staff recommendation is to assume that our market forces and planning processes would add capacity only just before we would otherwise fall below the Minimum Requirement. This effectively assumes that there is no conservatism built into assuring that we maintain reliability and that there will never be an instance where we plan for a forecast, and capacity is built to satisfy such forecast growth expectations, that turns out to be too high. This assumption is clearly inconsistent with past actions. For example, in 2001, the State, using NYPA as its vehicle, installed emergency generators in NYC. In that case, 450 MW of combustion turbines were added to the system through out of market measures to assure that we met our reliability needs. The response of the State and the amount of capacity that was added was much more than would be consistent with an average excess of one-half a GT. This new assumption that the market would have an average excess of only one-half of the proxy unit is also inconsistent with the decision to delay the retirement of Poletti two years because it was "needed for reliability." In each of the two years it turned out that Poletti was not needed to assure that we met the minimum capacity requirement, but, nonetheless, Poletti was retained because forecasts had indicated it was needed.

Moreover, in reducing NERA's assumed levels of surplus, the current NYISO Proposal has substantially reduced the representation of merchant risk. The assumed level of market excess is the main driver in incorporating merchant risk into the proxy unit Net CONE. Indeed, these newly recommended levels are well below the risk levels that are embedded in the current Demand Curves. Yet the NYISO has not identified any major changes in the market that in any way justifies that such risk has abated significantly and is expected to remain abated for the next three years.

With the NYISO's recommendation, the NYISO demand curves represent significantly less merchant risk than is assumed in determining the Net CONE in other markets. For example, PJM assumes a twenty year amortization period for its proxy unit and then sets its capacity demand curves by placing the unit's Net CONE at the point of 1% excess on the demand curve. The NYISO's recommended demand curves result in a 22.5 year amortization rate at the Minimum Requirement and therefore a significantly higher assumed amortization rate at the assumed equilibrium excess levels.

According to the NYISO Proposal, Dr. David Patton, the NYISO's Independent Market Monitor, "…expressed concern that [sic] the NYISO's proposed level of expected excess capacity in New York City of 1.1 percent. He indicated that it is not reasonable to expect this low a level of excess capacity over the long-term." The ICAP Demand Curves were implemented in New York, in part, to promote stability in the capacity market. Changing such a significant parameter without providing analyses or other support to justify such reductions or adjusting other financial assumptions in the model to account for this risk, will substantially undercut such stability. This impact is equally true with respect to attracting investment in NYC, Long Island, and the ROS. Thus, absent a legitimate rationale for substantially eroding this key assumption, the excess capacity levels that are currently used should continue to be applied for the next reset period. In any event, the excess capacity levels recommended by NERA, at the very minimum, should remain unchanged.

IV. PROXY UNIT TO SET THE NYCA DEMAND CURVE

NYISO Staff has recommended that the NYCA Demand Curve be based on the Net CONE (without, as noted above, including deliverability costs) of a Capital zone proxy unit. As demonstrated above, IPPNY supports setting the demand curve based upon either a Capital zone proxy unit including the cost of making the unit deliverable throughout the Rest of State Region (as required by the Tariff) or a Lower Hudson Valley proxy unit which presumably does not have significant deliverability costs. Some market participants have suggested that the NYCA Demand Curve should be based upon the estimated Net CONE for Long Island. First, it should be noted that this would be a violation of the tariff since section 5.14.1.2 requires that the demand curve be based on a unit in the rest of state region.

However, such an approach would be flawed. Initially, it should be noted that there has been little attention paid to the Long Island demand curves in this reset process as well as the past reset processes because Long Island Power Authority ("LIPA") procures most of its capacity by contract. Moreover, by virtue of the amount of excess capacity that it has procured in the past, this factor has the secondary effect of causing the Long Island Demand Curve to clear against the NYCA Demand Curve. Thus, the accuracy of these figures has never been reviewed or confirmed.[9]

Moreover, even if it could be confirmed that these figures were accurate, it still would not be appropriate to set the NYCA curve based upon NERA's estimated Net CONE for Long Island. The reason the Net CONE for Long Island is lower than the Net CONE of the Capital Region proxy unit is because, while the capital costs on Long Island are higher, the NERA Net Energy and Ancillary Service revenue model provided very high estimates for the net revenues of a new unit on Long Island. The demand curve model estimated that the Net Energy and Ancillary Service Revenues of an LMS100 unit on Long Island were more than 65% above the level for the same type of unit in New York City. Were these net energy and ancillary service levels to decline, the Long Island Net CONE would correspondingly increase.

For the Long Island Net CONE to remain below the Rest of State unit's Net CONE, these very high Net Energy levels would need to be maintained at these levels into the future. Essentially, the purported low Net CONE levels for Long Island can only remain if Long Island were to continue to be constrained from the rest of the NYCA and the Northeast electricity grid. While Long Island LBMPs might have been significantly higher than NYC LBMPs during most

[9] In its Report, NERA itself acknowledged that it was required to extrapolate the Long Island data significantly because Long Island has had very substantial excesses over the past three years, and thus, the reliability of these results may well be lower. (See NERA Report at 74-75.)

of the historic period used for the Net Energy modeling, this is no longer the case. Nor can it reasonably be projected to be the case in the future. Towards the end of the historic period, roughly 1000 MW of new efficient capacity was added to Long Island. This substantial capacity addition -- which matched about 1/5 of the Long Island peak load -- has significantly altered the resource base on the Island and, correspondingly, the energy prices on the Island. However, this change in the Long Island resource mix, which translated to the addition of efficient resources at a level equal to roughly 1/5 of the Long Island peak load, was not adjusted for in any manner in the net energy modeling.

Recent President's reports and CEO/COO reports to the Management Committee shows the impact of the resource change on Long Island. Long Island no longer has LBMP's that are substantially above, or even significantly above, the LBMPs for NYC. If the Long Island Curve had been estimated based upon the NYC Net Energy and Ancillary Service revenues, the Long Island Net CONE would have been significantly above the Capital Region Net CONE, even with deliverability costs included for the Capital Region.

The Long Island proxy unit should not be used to set the NYCA Demand Curve without first adjusting the Net Energy and Ancillary Service revenues for the substantial changes in the Long Island resource mix. Making this change at this point would most likely require significant analysis. The net result of such analysis would reveal that the Long Island proxy unit Net CONE is higher than that of the Capital Zone proxy unit inclusive of deliverability costs. Thus, even if it were permitted under the NYISO's Services Tariff, which it is not, the Long Island proxy unit would have a higher cost; therefore, it should not, in fact, be used to set the NYCA Demand Curve.

V. SHAPE AND SLOPE

IPPNY supports the NYISO Staff's and consultant's decision to maintain the current shape and slope of the Demand Curves for the reasons provided in the report. During the current surplus conditions, additional risk should not be foisted on investors by shortening the curve thereby making them more steep or adding a kink to the Curves for opportunistic reasons. Some Market Participants have suggested the slope and shape of the curve need to be addressed to ensure that consumers are not overpaying for capacity. IPPNY disagrees. Indeed, by its very design, the Demand Curve is finely honed to produce lower prices as the amount of surplus increases, i.e., it values surplus capacity less. These same Market Participants have not brought forth any evidence the current slope and shape of the curve result in unreasonably high capacity prices for consumers. Moreover, doing so will only serve to significantly raise the levelized cost of new entry as, by definition, a shorter curve means a steeper curve.

VI. ESCALATION OF CURVES

The current Demand Curves are escalated in years two and three based on cost increases contained in the Handy-Whitman Index for power-plant construction combined with the estimated inflation rate. In this reset process, NERA recommended an inflation rate of 2.4%. Initially, the NYISO Staff endorsed this inflation rate, stating, "The NYISO believes that the Consultant's use of the forecast 10-year average inflation rate of 2.4% is appropriate as an escalation rate factor for the second and third years of the three-year period."[10] However, less than two months later with no explanation whatsoever, NYISO Staff is now recommending an escalation of only 1.7%. This significant reduction in the recommended escalation rate is arbitrary and has not been supported by NYISO Staff.

VII. REAL-TIME GAS PRICES

Currently, the Net Energy and Ancillary Service model utilized by NERA assumes that a generator can obtain gas in the intra-day market at the same price that it pays for gas in the day-ahead market; the NYISO Staff recommendations accept this assumption. IPPNY and its members have raised concerns with this assumption during ICAPWG meetings and in earlier comments. During ICAPWG meetings, NERA confirmed that there was an intra-day gas premium but asserted that it was not able to calculate this differential with exact precision. Thus, at least as of this point, NERA's false assumption has been permitted to continue to stand. Most troubling, Shell Energy North America (US), L.P. ("Shell Energy") has produced an analysis that shows that purchasing gas in intra-day markets results in the generator paying a premium over prices in the day-ahead market. It shows that premiums can be applied in these markets due to gas supply having to be obtained from storage and suppliers consider opportunity costs when making these types of sales. However, to address this deficiency inherent in this reset process analysis, NERA suggests this issue should be studied in greater detail during the next reset process.

While the Shell Energy analysis was based on Transco Zone 5 prices, it confirms the fact that there is a premium that must be taken into consideration. The premium that Shell Energy's analysis showed was $0.65 per dt (Check me on this) In fact, Transco Zone 5 is upstream of NYISO ROS, and, as a result, intra-day gas price volatility in New York is most likely even greater, and thus understated in this analysis. The fact that it may be difficult to quantify does not justify not accounting for it at all during the current reset process. The Net Energy and Ancillary Services estimates should be re-run accounting for this additional intra-day gas cost. The impact of this correction is likely to be most significant for the NYCA proxy unit's revenues since this unit is assumed to achieve the vast majority of its revenues from the real-time market.

[10] "Proposed NYISO Installed Capacity Demand Curves For Capability Years 2011/2012, 2012/2013 and 2013/2014" 8/13/10 Pg 13

CONCLUSION

The NYISO Board of Directors should modify the NYISO Proposal in accordance with the foregoing discussion.

Dated: October 8,2010
Albany, New York

Respectfully submitted,

Christopher J. LaRoe
Managing Director, Market Policy
& Regulatory Affairs
Independent Power Producers of New York
19 Dove St, Suite 302
Albany, NY 12210

Appendix I

Deliverability Costs Related to Upgrading UPNY/SENY Interface

Mark Younger
Vice President, Slater Consulting

NYISO Installed Capacity Working Group
July 27, 2010

TO Claim Regarding Deliverability

If we were at the minimum ICAP requirement in that time frame, given projected load levels, it would not be necessary to pay for deliverability upgrades for new generation to be able to provide capacity. There is sufficient deliverability to serve current and projected load levels.

(Memo from Paul Gioia to Dave Lawrence, April 21, 2010)

CY 2008 Class Year Deliverability Study Results

- UPNY-SENY overloaded by 1,542.3 MW before the additional of any 2008 Class Year projects
- UPNY-SENY overloaded by 1,799.1 MW after the addition of the 2008 Class Year projects
- The overloads are presented in terms of UCAP MW
- The upgrade cost to relieve the incremental impact on UPNY-SENY is $177,920/CRIS-MW

What Has Changed

- Forecast peak loads are now forecast at lower levels in most zones
- Comparison of 2010 Gold Book forecast for 2015 to the 2009 RNA forecast for 2013 that was used for the deliverability study shows that zones A – F forecast loads have dropped by 137
- This translates to additional overload on UPNY-SENY taking the overload before Class Year additions to approximately 1,680 MW of UCAP terms or approximately 1783 MW of ICAP

How Do the Resources Look If We Are At or Near to Minimum Requirements

Zone(S)	Peak Forecast	IRM/LCR	Minimum Capacity Requirement	Expected Excess	Expected Capacity Level
NYCA	34,021 MW	118%	40,145 MW	101.5%	40,747 MW
Zone J	12,065 MW	80 %	9,652 MW	103%	9,942 MW
Zone K	5,417 MW	104.5 %	5,661 MW	107%	6,057 MW
Zones A-F	12,012 MW				
Zones G-I	4,527 MW				

Expected Upstate Capacity Level when at or near minimum requirements
NYCA Level is 24,748 MW (40,747 - 9,942 – 6,057)

Would Zones A – F Retirements Eliminate the Deliverability Problem?

	Zones A-F	Zones G-I
Current Capacity Level	17,804 MW	5,091 MW
Additions	580 MW	0 MW
CRIS Imports	1,125 MW	0 MW
SCRs	1,340 MW	143 MW
TOTAL	20,849 MW	5,234 MW

- Total ROS Capacity is
  26,083 MW
- Capacity Requirement after accounting for NYC and Long Island at expected levels is
  24,748 MW
- In order for a new unit to avoid being responsible for any deliverability costs, it would require retiring sufficient capacity to eliminate the overload and provide sufficient headroom for the new entry
- The 1,783 MW of UPNY-SENY overload is greater than the amount of capacity that Could be retired in Zones A - F

Other Considerations That Result In Deliverability Upgrade Costs Remaining

- CRIS Rights are transferrable; Retiring units may use or sell their deliverability rights for three years after they retire
- Consequently, the requisite capacity would not only need to be retired in zones A – F to eliminate the UPNY-SENY overload. Such rights must not have been transferred and, at a minimum, you would need to retire it long enough in advance to ensure that the deliverability rights have sunset and a new project to request and be evaluated for CRIS status

Other Considerations That Result In Deliverability Upgrade Costs Remaining (2)

- The 2010 Demand Curve analysis by NERA has shown that the net cost of building in Zone F including the deliverability upgrade costs is lower than the net cost of building in the Lower Hudson Valley
- All else equal, this will result in Zone F continuing to be the preferred location for upstate merchant capacity
- Failing to include deliverability costs in a Zone F based Demand Curve will result in inadequate revenues for new entry anywhere in the Rest of State region.

Conclusion

- The NERA analysis demonstrates that the proxy unit does not receive sufficient Net Energy and Ancillary Service revenues to cover all its costs, thus it must also sell capacity to be economically viable
- A unit will not qualify to sell capacity without paying to resolve any identified deliverability costs
- The NYISO's analysis of existing conditions shows that the existing system is not capable of delivering all resources above UPNY-SENY
- As the system approaches minimum requirements it will continue to be incapable of delivering all resources above UPNY-SENY
- Thus, the proxy unit for Rest of State must include deliverability upgrade costs