**2013 State of the Market Report**
**Comments of**

**Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., Long Island Power Authority, New York Power Authority, New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, Orange and Rockland Utilities, Inc., and Rochester Gas and Electric Corporation (referred to herein as the "NYTOs")**

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1. **Enhancements are Necessary for the Prioritization of Recommendations**
The State of the Market Report (SOM) provides recommendations, which are prioritized to help the NYISO and stakeholders determine which market changes should be pursued. In its report, however, the Market Monitor (MMU) provides little to no explanation as to why some recommendations are prioritized over others. The ultimate determination as to whether a recommendation is pursued is made jointly by NYISO and stakeholders as part of the budget prioritization process in the Budget Priorities Working Group (BPWG) in coordination with other stakeholder committees. To enhance the SOM report's usefulness in that evaluation process, the MMU should provide explanations, including as applicable cost/benefit analyses and/or discussions, justifying the priorities of its recommendations. This should be consistent with the methods that the NYISO has used to evaluate the cost/benefit of other market design changes. Moreover, the MMU should set-out and describe a consistent set of criteria for how it will determine the priority of its recommendations in future reports. At a minimum, the criteria should consider the net economic benefits to customers. Such details will aid the stakeholders and NYISO staff intimately involved in analyzing costs and benefits and identifying solutions. Generally, these improvements will enhance the transparency and usefulness of the SOM report as an input to the project prioritization process that takes place in the BPWG in coordination with other committees.

2. **The High Priority Recommendation to Optimize PARs Should be Reconsidered (Recommendation #5)**
The SOM recommends, as a "high priority," to operate PAR-controlled lines associated with established wheeling contracts to minimize production costs and create financial rights that compensate affected transmission owners. The NYTOs believe that the MMU's analysis that supports this recommendation is misleading and, consequently, its high prioritization was not adequately justified in the report. More research on the topic, including the operational challenges and costs is required. Of particular concern are the benefits estimated for modifying the flow on the transmission lines between Con Edison and LIPA. While there may be potential production cost benefits associated with modifying the flow at certain times, the MMU's analysis significantly overestimates these benefits in two ways. First, it assumes that the entire 300MW of flow can be reversed. This is inaccurate and misleading; as the MMU knows the 300MW wheel is needed for Con Edison system local reliability, and if optimized only a small fraction of this flow can be modified at certain times when reliability would not be affected.

Second, the MMU's analysis is not based on a MAPs model and relies on day-ahead market outcomes as a proxy for production cost savings. Considering that the MMU believed this to be a high priority, we believe a proper MAPs production cost analysis should be done to provide stakeholders with a more accurate estimate of the potential benefits. Considering that the benefits are likely much lower than what the MMU has estimated, we believe this recommendation should not have been qualified as a high priority and do not believe the MMU has sufficiently justified this categorization. Moreover, the MMU should have recognized the limited ability to accurately predict price divergence, as well as the ability to accurately optimize the PAR settings to bring about such changes in real-time; for instance the NYTOs believe that the highest impacts happen only over a few hours during the year which are sporadic and non-continuous. There are also other operational challenges and costs that the SOM should have considered. For instance such a change may increase the frequency of PAR movements beyond what is advised under good utility practice. Moreover, additional movements may be impractical since in-day scheduling changes would require more operator intervention, and changing PAR flow will have an impact on other PARs.

Nevertheless, the SOM correctly acknowledges that there are financial implications to Con Edison and Power Supply Long Island customers that need to be considered if any changes to the existing wheeling arrangements are pursued.

**3. Capacity Market Recommendations (Recommendations #1-3)**

The SOM highlights the role of the capacity market to ensure that sufficient capacity is available to meet New York's planning reserve needs and recommends that to better achieve this goal, the NYISO should adopt a "dynamic and efficient framework" for reflecting locational planning requirements in its capacity market. The NYTOs support the overall goals behind this recommendation but find the proposal identified in the SOM as fundamentally altering the current construct of the capacity market. The NYTOs believe that such an undertaking should be carefully considered by stakeholders weighing the purported benefits against the cost of implementation and in particular the potential implications to volatility, buyer-side mitigation and market power issues. The NYTOs believe this discussion and determination of priority should be made in the budget prioritization process and that the NYISO and stakeholders should consider any unintended consequences in their evaluation.

One key concern of the NYTOs is that the SOM proposal, to "modify demand curves to minimize the cost of satisfying planning requirements" may be inconsistent with the stated objective of providing for "increased stability in market signals" in the capacity market. Specifically, the NYTOs believe that the NYISO should demonstrate that pre-modeling capacity zones that may or may not bind in a short-term six month capacity market would not introduce an unmanageable risk that ESCOs and others will have difficulty hedging. Additionally, as the NYISO has yet to resolve the issue of unjustified price separation between zones once transmission constraints are relieved, modeling additional zones is premature. The NYISO should address the issue of unjustified price separation before considering pre-modeling zones which would exacerbate that issue. Finally, the SOM proposes that the LCR and/or demand curve be set such that the Net CONE per unit of reliability impact be constant for all localities. If the NYISO stakeholders are to consider such a change, the NYTOs believe that potential LCR volatility under its current and proposed constructs should be considered.

With respect to the recommendations on buyer-side mitigation, the NYTOs point out that several of these buyer-side mitigation measures have been thoroughly discussed in the stakeholder process and the results have not produced a consensus vote. The NYTOs do not have a consensus position on potential modifications to buyer-side mitigation that have been discussed. The NYTOs, however, unanimously oppose applying mitigation to uncontrolled AC transmission projects. AC transmission enhancements enable the markets and facilitate competition, and should not be mitigated.

In response to the SOM recommendation on supply-side mitigation (Recommendation #3), the NYTOs agree the NYISO should "modify the pivotal supplier test to prevent a large supplier from circumventing supply-side mitigation by selling capacity in forward auctions." Moreover, since FERC has now indicated that the NYISO should pursue this change, the NYTOs believe that this should now become a high priority.

Finally, the SOM recommends that in the future, a peaking unit may not be the most efficient choice to establish the reference unit for the demand curve and if this changes, the NYISO should use the most efficient technology. However such a change would not be possible under the current NYISO tariff. It isn't clear to the NYTOs why the modification of the NYISO tariff to allow for the most efficient unit was not listed as an explicit recommendation, but the NYTOs support the NYISO prioritizing this effort to ensure that the *"default resource upon which the capacity demand curves are based to always be among the most economic and realistic investment choices."*

**4. Operating Reserve Requirement and Demand Curve Recommendations Need Further Explanation and Analysis (Recommendation #10)**

The SOM finds that operating reserve market requirements did not match actual operating reserve requirements. It therefore recommends modifying operating reserve demand curves to reflect reliability needs that lead to out-of-market actions under high load conditions, including: (i) defining SENY 30-minute operating requirement and (ii) increasing the NYCA 30-minute operating reserve requirement.

NYTOs do not find that the SOM adequately justifies the need to increase the NYCA 30-minute requirement. Evaluating whether an increase to the NYCA 30-minute requirement is needed for reliability should be further analyzed in the NYISO reliability based stakeholder working groups. Like other recommendations, this recommendation needs greater detail and analysis justifying its designation as a high priority. As recommended above, cost/benefit analysis supporting this recommendation would be helpful. We understand that if stakeholders conceptually approve this item at the Business Issues Committee (BIC) to be further evaluated as part of the comprehensive shortage pricing review, the NYISO intends to develop such a cost/benefit analysis for stakeholder discussion.

5. **Fuel Usage Under Tight Gas Supply Conditions (Recommendations #11 and #12)**
   The NYTOs continue to believe that New York City's dual fuel requirements should be strengthened and formalized in New York's local reliability requirements or market rules. Gas-fired generators in New York City with an ability to switch fuels comprise approximately 45% of the state's total dual fuel capacity, and will continue to plan an important role in assuring that fuel security is maintained. The specific dual fuel requirements historically allowing operators to maintain the reliability of New York City's gas and electric systems should be recognized and adopted as part of the NYISO tariff.

   Longer-term, additional infrastructure may be needed to maintain fuel security in New York, especially as non-gas units retire. The NYTOs believe that regular, forward-looking studies should be conducted to guide the development of such infrastructure. This infrastructure may include not only increased electric and gas transmission infrastructure, but increased fuel storage for existing non-gas or dual fuel units, or increased demand response capability.

   The NYTOs believe that the SOM recommendation to consider ways to allow generators to submit offers that reflect certain fuel supply constraints in the day-ahead market should be further explored. When considering such changes, the NYISO and stakeholders should consider the potential for manipulation and abuse. It should also consider the dynamics of fuel supply constraints in the real-time market. Generators may face unique gas supply constraints in real-time operation, which may not be entirely predictable when real-time bids are submitted. As NYISO and stakeholders evaluate any such changes, it will also be important to consider the scope of software changes that may be required. Another area that requires more clarity is generator's ability to recover pipeline and LDC operational flow order (OFO) and/or imbalance unauthorized use charges in NYISO's markets. The NYISO should explain and provide details about its existing practices to stakeholders. It is critical that such practices do not give generators incentives that jeopardize gas system reliability.

   The NYTOs support requiring generators to provide daily information on fuel availability, and are curious as to why this was not made a high priority. Over the 2013-2014 Winter enhanced communications with generators about fuel availability provided numerous benefits. Enhancements permitting NYISO to have additional information should be explored by NYISO and stakeholders.

6. **Shortage Conditions (Recommendation #9)**
   The NYTOs support the SOM recommendation to modify real-time pricing during demand response activation as well as enhancing the flexibility of SCR calls. The NYTOs also support the SOM recommendation and NYISO efforts and consideration to migrate scarcity pricing into the

optimization software. It is unclear why these two recommendations were not made a high priority and the MMU should have explained why.

7. **Reduce Cyclical Real-Time Price Volatility (Recommendation #6)**
   We support this recommendation to explore modifications RTD and RTC to reduce unnecessary price volatility. We agree addressing this issue could help to reduce unnecessary combustion turbine starts, reduce uplift and result in a more efficient real-time dispatch. This is another example of where the MMU could have provided more information on its rationale for why this is not a high priority as this would be helpful input to the BPWG / NYISO prioritization process.

## Appendix – Comments and Questions on the Analysis of the Report

***Energy Market***

I. Congestion Related Issues

The NYTOs would appreciate additional detail and/or explanation on:

- The SOM's indication that real-time congestion on the 345 kV system in New York City, on Long Island, and on external interfaces was significantly higher than day-ahead congestion (Figure 2)
- Why one of the largest contributors to day-ahead congestion rent shortfalls is congestion on external interfaces (Figure A-62)
- How the inability of the market software to model a split ring bus properly led to balancing congestion shortfalls "when an expensive resource that was dispatched to resolve congestion in the sub-load pocket set LBMP in a wider area than appropriate, resulting in higher LBMPs" led to balancing congestion shortfalls (Figure A-62)

In addition, the SOM's analysis of market-to-market coordination indicates that "it would be beneficial to bring some additional flow gates into the M2M coordination process" (SOM at 97) because there are times when there are significant congestion differences between PJM and NY, even though no M2M flowgate constraints are binding. The data in the inset table (Figure A-79) support this contention. Calculations using those data indicate that when an M2M flowgate binds, there is about a 65% probability that the Ramapo line will be fully utilized when the congestion difference between NY and PJM is at least $20/MWh (in either direction), whereas if an M2M flowgate is not binding, that probability drops to about 18%. The NYTOs request additional information as to whether the NYISO is working on this, and if so, when we can expect to see a proposed list of additions.

The intrazonal component of day-ahead market congestion continues to exceed the intrazonal component of TCC prices on a regular basis. Figure A-68 reports that profit on these components of TCCs averaged 57 percent of the value of those TCCs. That is almost identical to the profit on these components of TCCs that was reported in the 2012 SOM, which was 58 percent (Figure A-52 of 2012 SOM). The 2013 SOM states "A significant share of these Intra-zonal TCC profits accrued on constraints in the West Zone, as the congestion pattern was not anticipated at the time of the TCC auctions" (Page A-92.) If intrazonal constraints in the West Zone are excluded, what is the profit on the intrazonal component of TCCs? And if it remains significant, could the MMU make data available on specific paths or flowgates that would highlight how profitable some of these paths are, which might encourage bidders to bid them up?

## II. Energy Market Withholding and Mitigation

The SOM indicates that the two largest suppliers derated a considerably larger percentage of their economic capacity than did other suppliers (Pages 16-17). The NYTOs note that Figure 5 in the 2012 SOM Report showed that the two top suppliers derated a much smaller percentage of their economic capacity at most load levels. Are the two top suppliers the same in both years?

The SOM also states, "Although the NYISO can require a supplier to re-schedule a planned outage for reliability reasons, the outage scheduling rules do not allow the NYISO to reschedule a supplier to re-schedule for economic reasons. In addition, there are no mitigation measures that would address outage scheduling that is not consistent with competitive behavior. It would be beneficial for the NYISO to consider expanding its outage scheduling authority." (Page 17.) Currently, proposed outage schedules are subject to approval by the local TO, to ensure that reliability is maintained. Any proposed changes to the outage scheduling procedures must continue to maintain reliability. Consequently, the NYTOs would appreciate additional explanation of how the changes to these procedures that the MMU envisions would operate, and how they would account for the need to preserve reliability while addressing anti-competitive conduct.

Has the MMU calculated any comparison of the size of the output gap in 2013 to 2012? It appears to be somewhat larger in 2013. The NYTOs note that Figure. A-39 through A-42 would be more useful if the vertical axis was rescaled to use more of the graph area.

The SOM indicates that in 2013 the NYISO invoked market power mitigation procedures both for generators with economic capacity that was not dispatched due to their above-reference offers, for generators that inappropriately used fuel price changes to modify their reference levels, and for physical withholding (Pages 18-19, n. 21 and 22, and A-55). Based on the previous SOM reports, these measures do not seem to have been invoked in 2012. The NYTOs would appreciate more information on what happened and whether there is need for concern.

Additionally, Figure A-43 indicates that automated mitigation applied in the day-ahead market was considerably more frequent in the 138 kV subpockets in New York City in 2013 than in 2012, and that the average amount of incremental energy that was mitigated as a result, was considerably higher. Is this mitigation included in, or in addition to, the mitigation described above?

## III. Energy Price Convergence

The NYTOs seek additional clarity as to why the day-ahead energy price premium was higher in 2013 than in 2012 in the Central and (especially) the Capital zones (Figure A-23). Note that net scheduled load was actually lower in the Capital zone in 2013 than in 2012, as shown in Figure A-53 (net load in the Central zone is not included in that group of figures), due to an increase in virtual supply; otherwise, the day-ahead energy premium would have been even larger.

Meanwhile, there was a significantly negative day-ahead energy price premium in Long Island in 2013 (–6.5%), compared to a small positive premium in past years. This appears to have been a consistent pattern through most of the year, as the MMU's quarterly reports showed negative day-ahead premium of about $7/MWh for the first three quarters of 2013. However, Figure A-24 indicates that there was a positive premium in February, November and (especially) December. Notably, there was a positive premium in those three months in 2012 as well, which may indicate a seasonal component to this difference. The discussion in the SOM says that increased volatility on Long Island was partly driven by "[i]nefficient utilization of some resources in the day-ahead market, which decreased the dispatch of lower-cost gas-fired generators and increased reliance on oil-fired generators" (A-37). Does this also explain the negative day-ahead premium? If so, why was it a consistent issue across most of the year, and is there anything that can be done to address it?

IV. Scarcity Pricing

How would the analysis on page A-140 of scarcity pricing during the July head wave, which concludes that scarcity pricing "was generally applied when demand response was actually needed," be affected if the black lines in Figs. A-86 and A-87 (which indicate the amount of demand response provided) and the red lines (which indicate the SENY reserve need plus the amount of demand response provided) were adjusted to reflect the actual amount of DR provided, instead of the amount requested? According to the NYISO's presentation at the February 19, 2014 MIWG meeting, the response rate varied from 63.7% to 76.4% for SCRs, while Emergency Demand Response Program response rates were much lower. This would lower the red and black lines by roughly 200 MW on the days when scarcity pricing was invoked in Zones G through K, and roughly 375 MW on the days when scarcity pricing was invoked statewide.

V. Demand Response

The SOM's discussion on demand response accurately states, "Moderating the quantities of DR that are deployed would help ensure that LBMPs better reflect the cost of maintaining reliability and that uplift charges are minimized" (Pages 68-69.) The NYTOs note that in addition to changing lead times and staggering deployment, limiting the geographic area in which these resources are activated can also accomplish this objective.

***Capacity Market***

While the SOM discusses other concerns with the procedures the NYISO uses to set the pivotal supplier threshold (which FERC recently directed the NYISO to correct), the MMU has never responded to analyses demonstrating that the NYISO's formula for calculating pivotal supplier thresholds will grant offer cap exemptions to entities with a financial incentive to withhold. The NYTOs request that the MMU address these concerns.

***Ancillary Services Markets***

I. Regulation

Comparing total costs shown in Figure A-34 for July through December 2013 to the same period in 2012 indicates that regulation costs have increased by about 30 percent. Gas prices were also higher in the second half of 2013 than in 2012, which may explain most or all of this difference. The NYTOs seek access to the data that would be needed to perform that analysis.

II. Operating Reserve Mitigation

The SOM suggests that relaxing day-ahead operating reserve mitigation provisions helped to improve convergence between day-ahead and real-time operating reserve prices, particularly during afternoon peak load hours. Is there any evidence to support this? By permitting higher day-ahead offers, these changes should have permitted better convergence in cases when day-ahead prices were predictably lower than real-time prices. And in fact, there was slightly better convergence in 2013 than in 2012 for the four time-of-year/product combinations shown in Table 4 for which the day-ahead price was less than the real-time price in 2012. But there was *much* better convergence in 2013 for the other five time-of-year/product combinations shown in that table, which should have been less affected by relaxing the day-ahead mitigation measures. This suggests that relaxing the mitigation measures had little to do with the improvement in convergence.

Similarly, review of Figures A-28, A-30 and A-32 does not suggest that the elimination of this mitigation improved convergence during afternoon peak load hours. For eastern 10-minute reserve and eastern 10-minute spinning reserve, the significant improvement in convergence in those hours occurred in January-April, but there was a large day-ahead premium in those hours in 2012; relaxing the day-ahead mitigation would not eliminate that premium. Similarly, for western spinning reserve, the improved convergence happened in May-Dec., but once again, the improvement consisted of eliminating a large day-ahead premium from 2012.