Comments on the 2014 State of the Market Report

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July 10, 2015

1. Improved Posting on the NYISO Website

The NYISO should reconsider how it posts the annual State of the Market reports. These are important documents and warrant a prominent place, or at a minimum a prominent link to their placement, on the NYISO website. Further, written stakeholder comments, like these, should be posted in the same place as the reports. We believe this will provide the necessary transparency and improved accessibility and as such should be implemented right away.

2. Future State of the Market Reports Should Enhance the Explanation and Criteria of Recommendation Prioritization

In our comments on the 2013 State of the Market Report (2013 SOM), we asked the MMU to "provide explanations, including as applicable cost/benefit analyses and/or discussions, justifying the priorities of its recommendations." The 2014 State of the Market Report (2014 SOM) contains a new section, at 98-100, that provides a general explanation of the criteria the MMU uses to prioritize recommendations. The descriptions of two of the three high priority recommendations in the 2014 SOM also briefly mention the cost savings that the MMU expects those recommendations would permit. We appreciate the addition of this information.

However, we believe that further enhancements would add clarity to the priority listings. As an initial matter, we think it would be helpful to provide a more robust explanation of why a recommendation is listed as higher priority over others. In particular, a discussion of whether and how multiple factors or criteria were considered when determining which recommendations should be high priority. As we noted last year, 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. A more complete understanding of the MMU's reasoning would assist us in determining how much confidence to place on those recommendations, which in turn could affect the prioritization process.

We believe that when relying on cost savings as the reason to make a recommendation a higher priority, more detail regarding the MMU's calculation of the production cost savings or investment cost savings would be helpful. We also believe that the MMU should consider criteria beyond or in addition to production cost or investment cost savings when prioritizing recommendations. For example, a recommendation that appeared in both the 2013 SOM and the 2014 SOM was to require generators to provide timely information on fuel availability. While this may not produce significant production cost or investment cost savings, it would have a significant impact on reliability. In our view, this could be an appropriate rationale for qualifying it for high-priority status. Similarly, it would be informative to have a deeper understanding for why another recommendation is not prioritized; for instance, its implementation may be complex with comparatively small benefit.

Finally, we find it confusing that some recommendations make the formal list of recommendations, while others are (i) made in the main body of the report; (ii) are summarized at the end of the Executive Summary; or (iii) reviewed at the end of the report. There is no explanation for why these suggestions have not led to a recommendation. For example, the 2014 SOM states, "It would be beneficial for the NYISO to monitor outage scheduling patterns going forward and consider whether its role could be expanded to enable more efficient outage scheduling" (2014 SOM at 20), however, this suggestion does not appear in the recommendation list. Unfortunately, given the volume of material in the report, suggestions that do not appear in the formal list of recommendations may be neglected. We would like to see the MMU address this be either adding such recommendations to the summary, or addressing in the body of the report why such a recommendation should not be included.

3. The MMU Should Reconsider Maintaining Certain Recommendations from Past Reports

Certain recommendations that have appeared in previous reports have been dropped from the 2014 report without explanation, even though they have not been implemented by the ISO.

- The recommendation in the 2012 State of the Market report (2012 SOM) that the ISO "select the most economic generating technologies to establish the [ICAP] demand curves" (2012 SOM at 81), which was reiterated in the 2013 SOM (at 55) (although it did not appear in the 2013 SOM's formal list of recommendations) is not mentioned in the 2014 SOM.

- The recommendation in the 2013 SOM that the ISO should "modify the pivotal supplier test to prevent a large supplier from circumventing supply-side mitigation by selling capacity in forward auctions" also is not mentioned in the 2014 SOM. (While a compliance filing in Docket No. ER13-1389 that was accepted by FERC on Aug. 5, 2014 eliminated this provision for the G-J Locality, the pivotal supplier threshold for New York City can still be evaded through sales of ICAP in forward markets.)

- The recommendation in the 2013 SOM that the ISO "modify the definition of the Starting Capability Period to coincide with anticipated entry of [an] Examined Facility" is also not mentioned in the 2014 SOM.

Our understanding from the MMU's response to inquiries is that these recommendations were omitted not because the MMU no longer believes the changes are advisable, but because changes in market conditions or other market rules led the MMU to conclude that these changes would not have as large an impact as they might have had in the past.

We believe the three recommendations above are still worthwhile and important to include in the 2014 State of the Market report. The report is intended to consider both short and long term issues for the markets, and unless the MMU has concluded that a recommendation is no longer advisable at all, we believe repeating these recommendations would appropriately keep them in the queue for stakeholder consideration over the long term. As we understand it, there is no limit or target number of recommendations for the State of the Market report. Moreover, if a recommendation made in a prior SOM is unaddressed and the MMU believes it is no longer warranted, it may be appropriate to include why the MMU believes the item no longer needs to be addressed.

4. The High Priority Recommendation to Optimize Flows Over Certain PAR-Controlled Lines Is Premature and Should be Reconsidered (Recommendation #7)

The 2014 SOM contains a high-priority recommendation, which is very similar to a high-priority recommendation appearing in the 2013 SOM, to operate PAR-controlled lines associated with established wheeling contracts (i.e., the 901, 903, A, B C, J and K lines) to minimize production costs. In the case of the 901 and 903 lines between New York City and Long Island, the 2014 SOM also describes (at A-94 to A-98) a procedure that could be used to create a financial payment to Con Edison customers, based upon LBMPs at either end of the 901 and 903 lines, in return for reductions in flows on those lines relative to a base case flow assumed when TCCs are awarded. (2014 SOM at A-94 to A-98.) In support of this recommendation, the 2014 SOM states (at A-137) that “use of the Waldwick lines to support the ConEd-PSEG wheeling agreement increased estimated day-ahead production costs by an estimated $22 million in 2014”, and that the inefficient operation of the 901 and 903 lines “increased day-ahead production costs by an estimated $14 million in 2014.” (*Id.*) While there may be theoretical benefits, we find these estimates to be unreliable and likely overstated.

We note that the 2013 State of the Market Report estimated $43 million of savings from optimizing the 901/903 PARs while the 2014 report now estimates $14 million – a 66% difference from one year to the next, underscoring the uncertainty of the benefits estimates.

While there may be production cost benefits associated with modifying the flow on these lines at certain times, the MMU’s analysis underestimates the complexity of relaxing PARs flow constraints to control production costs. It is extremely difficult to anticipate the specific times when the congestion will occur in Long Island, and this ability as well as the simultaneous requirement to reflect all salient reliability constraints in New York City severely limit the ability to reset PAR flow settings in real time and thus will likely reduce the impact that relaxing RT PAR flow constraints might have. In addition, there may be alternative ways to address real time price volatility on Long Island while maintaining contractual PAR flows.

The issue of real-time price volatility on Long Island is a result of transmission congestion and inefficient generation dispatch produced by the NYISO’s day-ahead and real-time market software. We believe the State of the Market report should look more broadly at the ways to address this, before focusing on 901/903 flow changes. We believe there are other remedies that the NYISO should explore to obtain DAM and RT price convergence.   For example, NYISO could (i) explore DAM ramping limits to reflect real-time ramping volatility since the RT ramp limits are more likely to result in systemic differences in prices and dispatch for quick start resources on western LI and; (ii) explore improving DAM dispatch and

RT PAR setting correspondence since at times the day-ahead market dispatch poorly reflects the RT PAR limitations, leading to economically inefficient day-ahead unit commitment on Long Island. We believe these solutions have the potential to significantly reduce the costs in real time. The NYISO should evaluate these changes prior to evaluating optimizing real time flow on Jamaica Ties 901, 903 - changes which would require altering a standing contractual agreement.

We think the high priority status for this recommendation is premature not only because the benefits are tenuous and the implementation complex, but because there are quite possibly easier ways to avoid the Long Island price spikes that make the flow inefficient at times. The NYISO and its stakeholders should first consider these other factors and potential solutions.

5. Capacity Market Recommendations (Recommendations #1-5)

The 2014 SOM repeats a recommendation made in the 2013 SOM that to better achieve the goal of ensuring that sufficient capacity is available to meet New York's planning reserve needs, the NYISO should "set[] capacity prices that reflect the marginal reliability value of additional capacity in each locality, [which] would provide more efficient incentives for investment and lower overall capacity costs." (2014 SOM at 100-101.) First, the NYTOs appreciate the MMU's responsiveness to consider how its Capacity Market recommendations from last year's report could be split into more manageable pieces and prioritized. While the NYTOs support the overall goals the MMU seeks to achieve, the proposed mechanism would require fundamental changes to the structure of the capacity market. The NYTOs reiterate our previously expressed belief 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.

Additionally, as we have demonstrated in the past, the ISO's current procedures for calculating capacity prices may yield unjustified separation between capacity prices in different zones even in cases when transmission constraints between those zones are relieved and capacity in those regions has the same marginal reliability value. Further, zonal capacity surpluses are not reflected across the zonal markets and they should be. Changes to buyer side mitigation rules would need to be considered to appropriately address circumstances where a nested zone has a higher locational requirement than its super zone. Consequently, we believe that modeling additional zones at this time would be premature. Instead, the issue of unjustified price separation should be addressed before considering pre-modeling zones which would exacerbate the potential for unjustified price separation. Future State of the Market reports should clarify that this proposal should not be implemented until these other concerns are addressed.

Moreover, as we noted in our comments on these recommendations last year, we are concerned that even if the price separation issues are addressed, this recommendation may not be consistent with the MMU's objective of providing "more price stability." Pre-modeling capacity zones that may or may not bind in a short-term six-month capacity market may introduce an unmanageable risk that LSEs will have difficulty hedging. Proposals to implement this recommendation should consider this risk. Similarly, the 2014 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 the potential for this to increase volatility in LCRs, which would impose similar difficult-to-hedge risks on LSEs, should be considered.

The NYTOs oppose the MMU's recommendation to apply buyer-side mitigation to uncontrolled AC transmission projects. They should not be mitigated because these transmission enhancements facilitate broader competition in the market.

6. Fuel Usage Under Tight Gas Supply Conditions (Recommendations #14-#16)

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 play 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.

In the 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 support the recommendation, which was carried over from the 2013 SOM, to consider ways to allow generators to submit offers that reflect certain fuel supply constraints in the day-ahead market. While it will be important to consider the scope of software changes that may be required, we believe the ISO should proceed with further development of this proposal. Permitting generators to specify costs associated with exercising permissible but more costly alternatives for the amount of fuel they can consume each day has the potential to increase efficiency, as it will eliminate the need for generators to submit offers that reflect their best guess as to how to allocate fuel over the course of the day. However, the NYTOs also believe that the ISO should consider permitting generators to submit similar offers in the real-time market. The constraints they face in real-time operation may be similar to the day-ahead constraints described above, in which case permitting generators to specify those constraints and the costs of exceeding them, instead of requiring them to submit real-time offers that reflect their best guess as to how their fuel should be allocated over time, may also produce efficiency gains.

The NYTOs also support another recommendation that was carried over from the 2013 SOM, which would require generators to provide daily information on fuel availability. In the winter of 2013-14, enhanced communications with generators about fuel availability provided numerous benefits. Enhancements permitting NYISO to have access to additional information should be explored by NYISO and stakeholders.

Finally, the 2014 SOM makes a new recommendation, indicating that the ISO should consider measures that would "allow it to identify unloaded capacity that is not capable of responding reliably in the event of a reserve pick-up." (2014 SOM at 110.) This would address the potential that some gas-fired units might not be able to obtain gas on days when OFOs are in effect, in which case the ISO would not be able to rely on such generators to meet its operating reserve requirements. (See 2014 SOM at 73-75.) We support the exploration of these procedures, although we note that implementing dual-fuel requirements in New York City, as recommended above, would address these issues for the city.

7. Shortage Pricing (Recommendation #11)

The NYTOs support the recommendation to incorporate scarcity pricing in the optimization software, and to apply scarcity pricing to imports and exports. In particular, we support the 2014 SOM's statement that "[i]t is important for … Scarcity Pricing to allow demand response to set prices only when it is needed to meet system needs." (2014 SOM at 107.) As was explained at a recent MIWG meeting, the ISO's proposed implementation of scarcity pricing would, in some cases, permit demand response to set prices when it is not needed to meet system needs. Consequently, we believe modification of its original proposed implementation is appropriate to ensure it only allows demand response to set prices only when it is needed to meet system needs.

8. Reduce Cyclical Real-Time Price Volatility (Recommendation #8)

We support this recommendation to explore modifications to RTD and RTC to reduce unnecessary price volatility. We agree that addressing this issue could help to reduce unnecessary combustion turbine starts, reduce uplift and result in a more efficient real-time dispatch.

<u>Appendix – Comments and Questions on the Analysis in the Report</u>

Energy Market

I. Congestion-Related Issues

Fig. 2 in each of the last three State of the Market reports compares day-ahead to real-time congestion on eight different transmission paths. In comparing day-ahead to real-time congestion over the last four years, as reported in these figures, the NYTOs note that for many of the paths, day-ahead congestion regularly exceeds real-time congestion. Specifically, for West-to-Central, Capital-to-Hudson Valley, NYC Simplified Interface Constraints, and Long Island, real-time congestion was higher than day-ahead congestion in each of the last four years, while for Central-to-East and NYC Lines in Load Pockets, real-time congestion was lower than day-ahead congestion in each of the last four years. We would appreciate additional explanation as to why the difference between day-ahead and real-time congestion rents on most of these paths tends to have the same sign from year to year.

The 2013 SOM's analysis of market-to-market ("M2M") coordination between New York and PJM indicated that "it would be beneficial to bring some additional flow gates into the M2M coordination process" (2013 SOM at 78) because there are times when there are significant congestion differences between PJM and NY, even though no M2M flowgate constraints are binding. Data in the inset table in

Figure A-79 of the 2013 SOM supported this contention. Calculations using those data indicated that during constrained hours in 2013 when an M2M flowgate was binding, there was about a 65% probability that the Ramapo line would be fully utilized when the congestion difference between NY and PJM is at least \$20/MWh (in either direction), whereas if an M2M flowgate was not binding, that probability dropped to about 17%.[1] Despite this, the 2014 SOM does not address the frequency with which there are significant congestion differences between PJM and NY even though no M2M flowgate constraints are binding, nor does it provide data that would permit us to update the analysis above for 2014. The NYTOs ask that those data be provided to market participants. We also would like to know whether the NYISO is working on this, and if so, when the NYISO expects to propose additional M2M flowgates.

The 2014 SOM's analysis of coordinated transaction scheduling ("CTS") between the NYISO and PJM concluded that during the first four months of CTS operations, only \$700,000 of the \$6.2 million in production cost savings that were anticipated at the time CTS transactions were scheduled are actually being realized. (2014 SOM, Table 10.) The 2014 SOM suggests that "reducing or eliminating the fees charged to transactions between PJM and NYISO would encourage more efficient utilization of the interfaces between the two regions," and that "improving the accuracy of the forecast assumptions by NYISO and PJM would lead to more efficient interchange." (2014 SOM at 54.) One other factor that the MMU should consider is the role of hourly pricing within PJM. Suppose, for example, that RTC schedules transactions under the expectation that the energy price for a given quarter-hour in New York will be \$50/MWh, while the price in PJM will be \$40/MWh. Also assume that the concerns described in the 2014 SOM have been eliminated—i.e., RTC's schedule is based on quarter-hourly prices that have been forecasted perfectly, and no fees are assessed by either ISO on interchange between them. In that case, it would be economic for CTS to schedule energy to flow from PJM to New York, with the amount scheduled to flow depending on the CTS bids that are submitted. But PJM will settle its side of the transaction at hourly prices, and if the hourly price in PJM is expected to be more than \$50/MWh, then market participants would not be willing to schedule energy to flow to New York in that quarter-hour, even though it is economic and the other issues identified in the 2014 SOM have been addressed, because they would expect to lose money due to the use of hourly pricing. Consequently, the MMU should consider the impact of hourly pricing in PJM on the efficiency of CTS. (The MMU's suggestions to improve CTS with PJM are another example of suggestions that could and should have been included in a more comprehensive summary of MMU recommendations. Indeed, given that the impact of

[1] When M2M flowgates were binding, the inset table indicates that 32% of the time, Ramapo was fully utilized and the congestion difference was more than \$20/MWh or less than –\$20/MWh; 12% of the time, Ramapo was not fully utilized and the congestion difference was more than \$20/MWh; and 5% of the time, Ramapo was not fully utilized and the congestion difference was less than –\$20/MWh. Consequently, the probability that Ramapo was fully utilized when M2M flowgates were binding and the congestion difference was more than \$20/MWh or less than –\$20/MWh was 32% / (32% + 12% + 5%) = 65%. Similarly, when M2M flowgates were not binding, the inset table indicates that 3% of the time, Ramapo was fully utilized and the congestion difference was more than \$20/MWh or less than –\$20/MWh; 6% of the time, Ramapo was not fully utilized and the congestion difference was more than \$20/MWh; and 9% of the time, Ramapo was not fully utilized and the congestion difference was less than –\$20/MWh. Consequently, the probability that Ramapo was fully utilized when M2M flowgates were not binding and the congestion difference was more than \$20/MWh or less than –\$20/MWh was 3% / (3% + 6% + 9%) = 17%.

improvements might well be more than $10 million per year, it appears this could have been a high-priority recommendation.)

II. Energy Market Withholding and Mitigation

The 2012 SOM, the 2013 SOM and the 2014 SOM each indicated that the two largest suppliers derated a considerably larger percentage of their economic capacity than did other suppliers. (See Fig. 5 in each SOM.) However, the SOMs differed in their explanations of this difference. The 2012 SOM found that the two largest suppliers "have portfolios that are primarily made up of older assets whose forced outage[] rates are not substantially different from that of other suppliers with similar assets. Hence, these ratings did not raise significant competitive concerns." (2012 SOM at 16.) But the 2013 SOM reached the opposite conclusion, "The high rates of deratings for the largest two suppliers are not explained by differences in the characteristics of the generator[s] that were derated, so they raise significant concerns about the efficiency of long-term outage scheduling of some resources." (2013 SOM at 17.) For the 2014 report both explanations were given credence, as the 2014 SOM stated, "While higher deratings for the two largest suppliers were *partly driven* by different generator characteristics …, they were *partly attributable* to different outage scheduling practices." (Emphasis added.) (2014 SOM at 19.) The NYTOs reiterate the request made in our comments on the 2013 SOM that the MMU indicate whether the two largest suppliers were the same in each of these years, as this could shed light on whether the differences in the SOMs' explanations may result from differences in the two largest suppliers from year to year.

As noted above, the 2014 SOM also states (at 20), "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 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 monitor outage scheduling patterns going forward and consider whether its role could be expanded to enable more efficient outage scheduling." This echoes a similar suggestion made in the 2013 SOM (at 17), even though neither suggestion was included in the respective list of recommendations made in those SOMs. The NYTOs believe that progress on this issue would become more likely if the MMU would provide additional explanation of how the changes to these procedures that it envisions would operate, and how they would account for the need to preserve reliability while addressing anti-competitive conduct. As such, we reiterate the request made in our comments on the 2013 SOM for this information.

Comparison of the output gaps reported in the 2012 SOM (Figs. A-29 and A-30), the 2013 SOM (Figs. A-39 and A-40) and the 2014 SOM (Figs. A-34 and A-35) suggests that the output gap has grown from year to year, although it is difficult to be sure because the SOMs do not report actual data on the output gap, and also because the vertical axis in these figures uses such a small proportion of the graph area. The NYTOs request that in future State of the Market reports, the MMU provide additional data on the size of the output gap that would assist in assessing whether the output gap is increasing or decreasing over time. We also reiterate the request made in our comments on the 2013 SOM that the MMU rescale the vertical axes in its output gap graphs to make them more useful to market participants.

The 2014 SOM indicates (at 21, n. 31 and 32) that in 2014, the ISO 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. The 2013 SOM contained similar statements (at 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 reiterate the request made in in our comments on the 2013 SOM that the MMU provide additional information on what happened and whether there is need to further address this concern.

III. Energy Price Convergence

Over the last three years, the day-ahead price premium in the Capital Zone has increased from 2.9% to 4.5% to 7.2%. (2014 SOM, Fig. A-21.) However, net scheduled load in the DAM in the Capital Zone has actually fallen over those same three years, from 94% to 91% to 88%, due to increases in virtual supply. (2013 SOM, Fig. A-53 and 2014 SOM, Fig. A-46.) Otherwise, the day-ahead energy premium would have been even larger. The NYTOs ask that the MMU consider what factors explain this increase in the day-ahead price premium in the Capital Zone.

IV. Demand Response

While the 2014 SOM did not address DR deployments due to the relative lack of those deployments, the 2013 SOM's discussion on demand response accurately stated (at 68-69), "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." In our view, this is another example of a suggestion that still appears to be advisable, and should therefore remain in SOM reports, even though it may not have been a significant issue in 2014. The NYTOs also 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. Consequently, if this suggestion appears in future reports, we believe it should be broadened accordingly.

Capacity Market

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 reiterate the request made in our comments on the 2013 SOM that the MMU address these concerns.

Ancillary Services Markets

The NYISO's revised regulation market went into effect on June 26, 2013. Total regulation costs for July through December 2013 were about 30 percent above total regulation costs during the last six months of 2012 (2013 SOM, Fig. A-34), and regulation costs in 2014 were 25 percent higher than regulation costs in 2013 (2014 SOM, Fig. 29), which raises the question of whether the revised regulation market may have caused costs to increase. Alternatively, the increase in regulation costs may be attributable to changes in gas prices. The 2014 SOM states (at A-46) that the increase in 2014 regulation costs, relative to 2013 costs, *primarily* occurred in the first quarter of 2014 due to higher gas costs, which led to higher energy prices and higher opportunity costs for providing regulation. If gas costs were the primary but not the exclusive cause of higher regulation costs, the future State of the Market Reports should also address other causes for the increased costs.

TCC Market

While the difference in 2014 was less than in previous years, the intrazonal component of day-ahead market congestion continues to exceed the intrazonal component of TCC prices on a regular basis. Figure A-59 of the 2014 SOM reports that profit on these components of TCCs averaged 34 percent of the value of those TCCs, whereas in 2012 and 2013, profit on these components of TCCs averaged 58 and 57 percent of the value of those TCCs, respectively (2012 SOM, Fig. A-52 and 2013 SOM, Fig. A-64). The 2013 SOM stated (at A-92), "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." However, while the 2014 SOM addressed differences between congestion in the TCC market and the day-ahead market across Central East and into and within SENY, it did not address any difference between congestion in the TCC market and the day-ahead market in the West Zone. An issue remains as to whether there are still significant differences between congestion in the TCC market and the day-ahead market in the West Zone. If so, the MMU should make data available on specific paths or flowgates that would highlight how profitable some of these paths are, which in turn might encourage bidders in the TCC auction to increase their bid for them. Also of importance is whether there are other paths that also exhibit similar systematic differences for which such data could be provided.

The 2014 SOM states (at 44), "the level of congestion was increasingly recognized by the markets from the annual auction to the six-month auction and from the six-month auction to the reconfiguration auction. This is expected since more accurate information is available about the state of the transmission system and likely market conditions closer to the actual operating period." However, it then goes on to say that "selling more of the capability of the transmission system in the monthly Reconfiguration Auctions would likely raise the amount of revenue collected from the sale of TCCs." The NYTOs would appreciate a fuller explanation of the rationale underlying this conclusion. While one would certainly expect that outcome to occur in the event that expectations of congestion are increasing over time, it is not clear why one would expectations of congestion would be expected to increase over time.