April 20, 2015

<u>Analysis Group Report: Evaluation of Transitioning to a Forward Capacity Market</u>
Comments of

Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., 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 "indicated NYTOs")

<u>Position Summary</u>

While The Analysis Group did not find an overwhelmingly compelling case to move to a forward market in the near-term, we do not think this report should forever close the door on considering a forward market. Market dynamics may change and alternative solutions may or may not come to fruition – accordingly we may want to consider forward markets again in the future.

<u>Outline of Comments</u>

1) It would have been a more informative approach if Analysis Group had outlined some of the shortcomings in today's capacity market that could be addressed with a forward market design or other revisions to the ICAP market.
2) Notice of retirements is one significant advantage of a forward market. Under the current notice requirement, a unit can simply rescind its notice. By comparison, the forward market commitment in PJM has proven to have provided ample notice of generators' intent to cease operation. It would have been helpful if the report had commented on how forward markets have led to greater visibility of generator retirements in other regions. More advanced notice of generator retirements would also better inform the assumptions used in the Comprehensive Reliability Planning Process ("CSPP").
3) The report does not sufficiently support its conclusion that NYISO's planning process options are significantly different from PJM and ISO-NE. Whether or not market solutions are solicited through the capacity market or ultimately satisfied through the CSPP, all three regions seek to find market solutions in advance of triggering a regulated solution. All three regions also have ways to trigger regulated reliability solutions and implement reliability must run contracts if a generator is needed for reliability. The report's claim that the NYISO's markets are not inadequate because the NYISO has another way (CSPP) to assure resource adequacy aside from a forward market may eliminate one reason for a forward market, but it's not a good reason to say the CSPP is working well. Triggering regulated solutions should not be viewed as a desirable outcome in competitive markets.
4) It's not clear how the Analysis Group translates the dollar difference between a spot market ("SM") and a forward marker ('FM") to a percentage difference. The cost increase percentages seem overstated. In particular, while offers made by owners of existing resources into the SM may tend to be lower than offers made into a FM, because fewer costs can be avoided at the time that an offer is made into the SM, the quantity offered is also likely to be smaller in the SM than in the FM. A resource that is considering mothballing or retiring can submit an offer into the FM and decide whether to proceed with mothballing or retirement on whether that offer is

accepted. Under the SM structure, such a resource may simply decide to mothball or retire if it does not expect to realize sufficient revenue in the SM to support continued operation. Consequently, to the extent that the analysis accounted for higher offers under the FM but not for the difference in the amount of capacity offered in the FM as compared to the SM, it may have overestimated the impact of an FM on end user capacity costs.

5) As the report discusses, there two primary ways in which load forecast error may cause prices to be higher in an FM than in an SM. First, load may, on average, be overforecasted in the FM. This causes more capacity to be purchased in the FM. The additional capacity may be bought out in subsequent reconfiguration auctions, which use lower load forecasts, but since the price in those auctions tends to be lower than the FM price, the result of the excess procurement in the FM is an increase in cost. Second, even if the load forecasts used for the FM are unbiased on average, the impact of these errors on prices is asymmetric, as over-forecasts tend to raise prices more than under-forecasts tend to lower them. (Pp. 57, 88.) A hold-back could help to offset both of these impacts of load forecast error. It would reduce the amount of capacity that would have to be purchased in the FM, thereby permitting the expected price of capacity in the FM to be consistent with the expected price of capacity in the SM (and eliminating potential incentives for the provision of "virtual capacity," which, as the draft report notes (at 70 and 74) raises concerns about whether resources committed in the FM would have been physically able to deliver on their commitments). If the amount of the hold-back is limited to amounts of capacity that demand response resources can reasonably be expected to deliver in subsequent markets, this sort of concern should not arise. Consequently, the report should have examined the advantages that a hold-back provision could have provided with respect to limiting the cost to customers in the over-forecast scenario, as well as allowing more flexibility for demand response to participate in the capacity market.
6) The cost to customers of the over-forecasting scenario is a significant concern but the potential impact and likelihood of this should not be overstated. There are measures that can be taken to limit this scenario from happening. As discussed earlier, a hold-back can be implemented to counteract any bias. The ISO can also simply work to correct over-forecast bias.
7) Page 45: We do not follow why a lock-in would result in lower credit ratings.
8) It would have been nice to include a chart of total cost to load – the analysis explains on page 55 how to get from the analysis to the increase to all-in energy prices. It would be good to see the extra step shown in a chart.
9) Pages 16 and 21: Weren't the capacity offers modeled as fixed and variable operating expenses minus expected energy and ancillary service revenues, rather than the other way around? Otherwise, the more profitable a unit, the higher its capacity offer.
10) On page 27, the draft report states, "PJM recently proposed a 'safe harbor' such that capacity performance resource offers may bid up to the Net CONE for its applicable region," which the draft report states is "similar to the NYISO's existing supply side mitigation offer cap in mitigated capacity zones … [is] the higher of the UCAP reference level, and the unit specific reference price…." This incorrectly describes the existing NYISO offer cap. Sec. 23.4.5.2 of the Services Tariff states, " Offers to sell Mitigated UCAP in an ICAP Spot Market Auction shall not be higher than the higher of (a) the UCAP Offer Reference Level for the applicable ICAP Spot Market

Auction, or (b) the Going-Forward Costs of the Installed Capacity Supplier supplying the Mitigated UCAP," but the UCAP Offer Reference Level is defined in Sec. 23.2.1 as "a dollar value equal to the projected clearing price for each ICAP Spot Market Auction determined by the ISO on the basis of the applicable ICAP Demand Curve and the total quantity of Unforced Capacity from all Installed Capacity Suppliers in a Mitigated Capacity Zone for the period covered by the applicable ICAP Spot Market Auction." Consequently, the UCAP Offer Reference Level is not based on Net CONE. Instead, it reflects the price that would be calculated in a region if all UCAP in that region were sold.

11) In the "All Coal Retirements with No Spot Market Entry" scenario, all remaining coal units are assumed to retire, with new entry at net CONE. Given that, it is difficult to understand some of the results for that scenario. For example, according to Figure 18, the ROS price in the coal retirement scenario (with no lock-in) is lower than the ROS price in the "New Entry at Net CONE" scenario, despite the fact that entry in both scenarios is at net CONE. Similarly, it is difficult to understand why awarding RSSAs to half of those units, as assumed in the "All Coal Retirements with Spot Market Reliability Assurance Support Services Agreements," causes an increase in the ROS price.