Evaluation of the New York Capacity Market

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Executive Summary

There are no critical flaws in the design of the New York ISO capacity market that the NYISO and its stakeholders are not currently addressing. They are in the process of correcting the principal problem area in the present design, which is the need for one or more additional capacity zones east of Central East and, more generally, the implementation of a process for defining new capacity market zones. In this paper, we identify a few modest changes in the current design that, additionally, would likely improve the performance of the capacity markets. As requested, we also evaluated the pros and cons of implementing a design supporting procurement of capacity further in advance of the operating year. We find that such a design would improve the performance of the New York ISO capacity market in some respects but would also have other adverse impacts. On balance we conclude that there is not a compelling case for a transition to such a design at this time.

The key change in the New York ISO capacity market design that is needed at present is the addition of one or more new capacity market zones east of Central East. This would be the first implementation of a routine process for identifying potential new capacity zones and modeling them in capacity market auctions prior to the time that they are needed to support reliability and ensure efficient outcomes in the capacity market. The design in the New York ISO's November 7, 2011 compliance filing could provide the methodology for adding the additional needed zone or zones, provided that it is applied in an appropriate manner. Namely, as discussed further in Section IIE below, it is essential that the evaluation of the need for additional capacity market zones be forward looking, identifying new zones prior to the time that they are needed, and thereafter representing them in relevant capacity market auctions without regard to whether the New York ISO projects them to bind in a particular auction. It is also essential that the evaluation of the need for new zones take into account all existing generation and all generation in the interconnection queue that seeks to participate in the capacity market, so long as this generation has in-service dates reasonably expected to fall within the forward-looking time frame of the demand curve reset and evaluation of the need for new capacity market zones.

As it works to develop the specific processes and procedures that will be used routinely to identify new capacity market zones, the New York ISO should avoid a policy of relying on increasingly specific capacity market requirements to support the particular types of generating capacity or capability needed to meet energy and ancillary service market reliability requirements. A capacity market design will work best, or at least less badly, if it is used for the narrow objective of replacing the missing money arising because reserve shortage prices are set below the level that would support resource adequacy in an energy-only market, rather than if it is used to attempt to ensure the procurement of capacity with the particular characteristics needed to meet specific reliability requirements. Hence, we recommend that contemporaneously with the evaluation of the need for new capacity market zones, the New York ISO also perform a forward-looking evaluation of reliability requirements that may not be appropriately priced in the energy or ancillary service markets. The New York ISO may find cost-effective opportunities to address reliability requirements that would otherwise be contributing to the potential future need for a new capacity zone through changes to the prices and operation of the New York ISO energy and ancillary service markets.

In the body of this report we make several additional recommendations for improvement to the New York ISO capacity market design:

- Greater reliance on energy market and ancillary service revenues to support needed capacity resources and capabilities;
- The use of a demand curve for installed capacity that reflects a reasonable assessment of the incremental reliability value of capacity.

The recommendation to place greater reliance on energy and ancillary service revenues to support capacity needed to meet reliability targets established by the new York State Reliability Council and state and federal regulators has a number of drivers and elements. First, the use of a capacity market to make up the "missing money" needed to support the capacity required to meet capacity requirements has the unintended consequence of creating a series of missing incentives relative to an energy-only market such as that maintained in ERCOT. The New York ISO attempts to replace these missing incentives with a series of administrative rules and requirements, some of which work better than others. Operational performance and investment incentives would be improved if capacity market resources were more reliant on energy and ancillary service revenues to attain an adequate return of and on their assets, while maintaining the role of the capacity market to make up the residual "missing money."[1] We do not recommend that the New York ISO eliminate its capacity market mechanism. Rather, the New York ISO should make changes at the margin that somewhat increase the importance of energy and ancillary service revenues relative to capacity market revenues, with the goal of providing improved incentives for resource performance and investment.

In addition to weakening resource performance and investment incentives, the failure to represent and price reliability needs in the energy and ancillary service markets has other unintended consequences. For example, it will contribute to the need for the New York ISO to establish an increasing number of smaller capacity market zones, increasing the burden on the New York ISO to mitigate buyer and seller market power in these increasingly numerous capacity zones.

We have three specific concerns with the current market rules that we recommend addressing by making changes to shift more revenues from the capacity market into the energy and ancillary services markets.

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1 Because the New York ISO operates its electricity system on a market basis, it does not ensure that all market participants necessarily will recover the "missing money" in capacity market payments; instead, it provides them the opportunity to recover their costs and earn profits through the operation of the energy and capacity markets. Some resources may be uneconomic and exit the market because they cannot recover their going forward costs, while other resources may at times earn short-run economic profits.

First, there is an inconsistency between the operational decisions to activate demand response resources (both Special Case Resources and Emergency Demand Response Program resources), and the current (lower) shortage prices for 30-minute resources. Emergency Demand Response Program resources are paid the greater of the LBMP price at their location or $500 per megawatt hour, and Special Case Resources are paid the greater of the LBMP price at their location or their minimum pay bid (capped at $500 per megawatt hour) to reduce energy consumption in order to restore NYCA 30-minute reserves; the inconsistency arises because these prices may be paid during conditions when the shortage prices for NYCA 30-minute reserves are much less than $500. In light of the reliability value of reserves that is reflected in the New York ISO's demand response activation decisions, the shortage values for 30-minute NYCA reserves need to be raised so that the prices are consistent with the cost of demand response activated to alleviate such reserve shortages, at least for severe reserve shortages.

Second, there is an inconsistency between the operational decision to activate demand response resources (both Special Case Resources and Emergency Demand Response Program resources) south of Leeds-Pleasant Valley and or Athens-Pleasant Valley, which are paid $500 to reduce energy consumption in order to satisfy transmission security requirements, and the failure of the New York ISO market design to attach a distinct price to these reserves in either the day-ahead market, Real-Time Commitment or Real-Time Dispatch. Thus, when these transmission security conditions exist and there is undispatched capacity south of these constraints, this undispatched capacity currently receives the same price as other resources meeting the eastern 10-minute reserve requirement, which includes all reserves east of Central East. The mis-pricing occurs when demand response resources are activated and receive $500 per megawatt hour to meet transmission security requirements that could also be met through undispatched reserves south of the constraints that are being compensated based on much lower reserve shortage values.

Third, the potential need for a new capacity market zone within New York City defined by the 138/345 kv system, as discussed by the Independent Market Monitor in his 2012 report,[2] raises a concern that there are additional reliability requirements In-City that are not reflected in energy and ancillary service prices under the current design. If such reliability requirements are not reflected in energy and ancillary service markets, they will contribute to future needs to establish additional, smaller capacity market zones to meet these reliability requirements. We recommend that these and similar reliability requirements be reflected to the extent feasible in energy and ancillary service market constraints and prices, rather than defaulting to resolution through creation of new capacity market zones or requirements.[3]

A second modest change that we recommend in this report is that the slope and zero crossing point of the capacity market demand curve provide a reasonable representation of the reliability value of incremental capacity. As discussed in Section IID, we have found, based on an analysis carried out jointly with the New York ISO, that the current demand curves are generally consistent with these criteria.[4] We do not recommend the use of a demand curve that is flatter than the actual demand curve in order to stabilize prices or mitigate potential market power (because a flatter slope means that the capacity price will change less with any given change in quantity). Our concern is that the use of a demand curve with a flatter slope will tend to stabilize the capacity price at the level of the estimated CONE. While stabilizing the price at this level might appear to be a sensible policy under the assumption that the estimated CONE provides a very accurate measure of the long-run competitive price of capacity, we do not view this as likely to be the case. We believe that the estimated CONE generally provides only a rough approximation

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2 David B, Patton, Pallas Lee Van Schaick, and Jie Chen, *2011 State of the Market Report for the New York ISO Markets*. April 2012, p. 38.

3 Another example of a potential reliability need that we recommend be addressed in the energy and ancillary service markets, rather than through capacity market requirements, is the potential future need for additional ramping capability to better accommodate the variability of intermittent resource output.

4 The New York ISO's analysis of the reliability value of incremental capacity described in this report should be viewed as indicative, and another analysis should be completed to evaluate the reliability value of incremental generating capacity in each zone after the procedures for calculating the local capacity requirement for new zones have been determined.

of the competitive price of capacity.[5] Hence, an artificially flat demand curve is likely to inappropriately maintain a capacity price that is less than or greater than the actual competitive price and potentially lead to the procurement of substantially more or less capacity than is appropriate from a reliability standpoint.

We also do not recommend an artificially steep demand curve as this would magnify the impact of capacity surpluses or shortages on prices, as this could lead to unwarranted volatility in capacity market prices. Determining the slope of the New York ISO capacity market demand curve based on estimates of the reliability value of incremental capacity avoids the disadvantages of an artificially flat or steep demand curve and would provide guidance on how the demand curve should be established when demand curves need to be defined for new capacity zones.

We have found based on the analysis we conducted jointly with the New York ISO that the current demand curves are generally consistent with the reliability value of incremental capacity, the slope of the demand curves tend to be too flat for shortfalls in capacity relative to the reliability target, meaning that the price does not rise steeply enough for shortfalls. While the New York ISO seeks, and has in the past maintained, capacity equal to or above the target level, it should nonetheless improve the alignment of the slope of the demand curve in the range of capacity shortfalls with the actual reliability value of this capacity.

If one accepts the view that the New York ISO's capacity demand curves should reflect the reliability value of incremental generating capacity, then there is also a logical inconsistency between the way the local capacity requirements are determined for Zones J and K and the way the local capacity market

5 Such an artificially flat demand curve can also have unanticipated consequences when new capacity market zones are created, particularly if the estimated cost of new entry overstates or understates the actual cost of new capacity, or if there is a capacity surplus or shortage in the new zone or zones, potentially causing prices to separate across capacity zones when there is no difference in the incremental reliability value of capacity.

demand curves currently are defined for these zones. The loss of load expectations currently are calculated for Zones J or Zone K by shifting capacity from Zone J to upstate New York or from Zone K to upstate New York. Total NYCA capacity is held constant in this process. Because of the way the Zone J and Zone K local capacity requirements are established, the capacity level at which incremental Zone J or Zone K capacity has no impact on the NYCA loss of load expectation is not the capacity level at which Zone J or Zone K capacity has zero incremental reliability value. It measures, instead, the point at which incremental Zone J or Zone K capacity has the same reliability value as upstate capacity.

This understanding of the meaning of the level of capacity at which the loss of load expectation falls to zero has implications for how the locational capacity market demand curves for Zone J and Zone K used in the spot auction should be anchored. If the demand curve is measuring the additional value of the local capacity relative to NYCA capacity, it is defining a premium relative to the NYCA capacity price. This might suggest that the anchor at the top of the demand curve would not be net CONE for the local region but would rather be the difference between the net CONE for the local region and for the NYCA. Or, if the demand curve were measuring the total value of local capacity, the anchor at the top of the demand curve would be the net CONE for the local region, but then the lower bound would not be the zero crossing point, but the value of NYCA capacity. If our view that the New York ISO's capacity demand curves should reflect the reliability value of incremental generating capacity is accepted, there would be more than one way to resolve this conceptual inconsistency. We do not make any specific recommendation as to how the conceptual inconsistency should be resolved.

With respect to the New York ISO's mitigation design for buyer market power, we do not recommend any major changes in the current rules for setting mitigated offer prices. We recognize that the design is imperfect in operation, but this is inevitable given that it must be based on imperfect information and forecasts. It is important to recognize that the estimates of entry costs, of energy and ancillary services market revenue, and avoidable going-forward costs are, by their nature, imperfect. An important element of the mitigation design is to constrain the exercise of market power without introducing even greater market distortions through the rigid application of mitigation based on data or criteria that are imperfect estimates of costs and market conditions. In this regard the 2010 changes to the rules used to determine when the offer floor for non-exempt supply will no longer be imposed appear to be in the right direction, as they are based on actual capacity market results rather than on forecasts or arbitrary and uneconomic thresholds for the maximum or minimum mitigation period.

An issue that we did identify in the buyer-side mitigation design is the assumption, used in estimating the impact of generation entry, that the supply of demand response is completely price inelastic. This assumption could potentially have a significant impact on the outcome of the test if the role of demand response increases, and we recommend that a more accurate approach be developed in the long run.

We suggest revisiting the structure of how buyer market power mitigation is applied. A problem with minimum offer price rules, such as those applied by the New York ISO (or by PJM), is that the mitigation of the offer price affects the opportunity for the offer to clear in the market as well as the clearing price. By contrast, an approach similar to the alternative capacity price rule (APR) proposed previously in New England, would separate the ability of new resources to clear in the market from the impact of that entry on the capacity clearing price paid to existing resources. The NYISO should consider whether such a structure would be an effective way to improve on the current design and, if so, rise again with FERC the possibility of moving to an alternative capacity price rule structure for buyer-side market power mitigation.

A further recommended change would be to exempt from buyer-side market power mitigation new resources that are not associated with any entity possessing buyer-side market power, just as there is an exemption in the seller market power mitigation rules for resources controlled by entities lacking seller market power. We do not prescribe the specific criteria for identifying such resources, which could be determined in a New York ISO stakeholder process, but recommend generally that mitigation not be applied to completely merchant generator facilities that have not sold their output or capacity forward. These plants are dependent on spot market prices for their return of and on investment.[6] Furthermore, an exemption should be established for capacity contracted for by individual load serving entities below a threshold size that would encompass both small municipal load serving entities and small competitive retail entities, which clearly lack buyer-side market power.

With respect to the CONE used to anchor the New York ISO capacity market demand curve we do not make a firm recommendation concerning the choice between continued use of an estimated net CONE based on a combustion turbine unit versus an estimated net CONE based on a combined cycle unit. Either of these resources may be the least-cost source of incremental capacity in future New York ISO capacity market auctions, with combustion turbines more likely to be least-cost if gas prices remain low and combined cycles more likely to be least-cost if gas prices rise substantially. If the costs and revenues of a combined cycle unit are used to determine the CONE and net CONE is used to anchor the New York ISO capacity market demand curve, more care will need to be taken in estimating energy and ancillary service revenues,[7] and more careful consideration will need to be made of the impact of the scale of entry on prices, than if a combustion turbine is used to anchor the New York ISO capacity market demand curve.

The cost to power consumers of reducing consumption in order to provide incremental demand response would not provide a workable basis for setting net CONE because it is inherently customer specific, reflecting the net cost of reduced consumption unique to that consumer, rather than a generic cost that can be benchmarked in the same manner as the cost of building a generating facility. Given the difficulty in

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6 Similarly, power consumers providing demand response solely in exchange for capacity and energy market revenues provided by the New York ISO, should not be subject to buyer side mitigation.

7 This would include testing the energy and ancillary service model over a time frame that includes levels of capacity that are close to the target level use to anchor the demand curve so that these revenues are not extrapolated materially outside the range of the data used to develop the estimates.

predicting what kind of resource will be marginal and the potential inaccuracy in the estimated CONE, even if the correct type of unit is selected, we are more concerned that the demand curve slope be based on the incremental reliability value of capacity than with the type of unit used to anchor the curve. This will provide the correct demand price signal for increments or decrements to capacity from the target level.

We do not recommend that the New York ISO extend its current capacity market to include capacity payments for permanent reductions in load, i.e. for the impact of energy efficiency investments on peak demand. There are several reasons for this recommendation. First, within the New York ISO's current design, reductions in peak load attributable to energy efficiency investments would be reflected in a reduction in capacity market procurement within one year, so compensation would come through a decrease in this capacity obligation. Second, including permanent reductions in peak demand in the capacity market program requires that projected peak demand be grossed up so as not to double-count the reduction. While it would not be particularly complicated for the New York ISO to make an adjustment in its capacity market to add past cleared demand reductions back into peak load, as do ISO New England[8] and PJM,[9] similar adjustments would need to be made not just within the New York ISO capacity market but also throughout the entire process of allocating capacity costs to retail consumers in order to avoid unintended cost shifts. We have not identified any benefit to introducing such complexity.

If the New York ISO were to move to a forward capacity procurement auction, there would be a longer interval between the time that a permanent reduction in peak load is observed and the time it is reflected in the amount of capacity procured. If the New York ISO were to shift to a design in which capacity was procured several years prior to the operating year, there might be a need to implement a process by which

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8 Energy Efficiency Forecast Working Group of the ISO New England Staff , "Draft Final Energy-Efficiency Forecast," March 16, 2012 ,p. 57 at http://www.iso-ne.com/committees/comm_wkgrps/othr/enrgy_effncy_frcst/frcst/2012/draft_final_ee_forecast_3_16_12.pdf

9 PJM, "Manual 18B: Energy Efficiency Measurement & Verification". March 1, 2010, p. 6, found at http://pjm.com/~/media/documents/manuals/m18b.ashx

consumers could commit to future reductions in peak load, the New York ISO's procurement of future capacity would be reduced to reflect those reductions, and consumers' would be allocated capacity costs based on their peak load reflecting the committed reductions. As discussed in the body of the report, however, implementing such a process in a forward procurement process is not straightforward and would involve many design choices because of the potential for the offer of energy efficiency load reductions to be a mechanism for arbitrage of the ISO load forecast. We do not recommend any particular design for accommodating energy efficiency load reductions in a forward capacity procurement process because of the many potentially complex choices that would need to be made, and because we do not identify a compelling need for the New York ISO to implement a longer-horizon forward capacity market. The details of how to account for permanent reductions in load within such a market could be addressed in the New York ISO stakeholder process if and when a decision is made to develop such a forward capacity market.[10]

Finally, the implementation of a forward capacity procurement process similar to that employed by PJM through its RPM capacity market design would provide the New York ISO, regulators, market participants in general and generation developers and demand response providers in particular with greater visibility concerning the expected cost of keeping existing generation in operation during a time frame in which replacement generation, transmission upgrades or demand response resources could more readily be developed. However, we have concluded that these benefits are not compelling at this point in time. We have five reasons for this view.

First, while uncertainties regarding future changes in environmental regulations and public policy decisions (e.g. the possible shut-down of Indian Point nuclear generating facilities) have created uncertainties concerning the future operating status of some generating capacity in New York and

10 Another issue to be considered in such a process would be how to account for permanent reductions in demand that were funded by New York Public Service Commission programs or NYSERDA rather than the consumer.

uncertainties regarding the capacity price required to keep some New York generating resources in operation, implementation of a forward capacity procurement process will not reduce these environmental uncertainties nor reduce the public policy uncertainties. Furthermore, by the time that a forward capacity procurement process could be designed, agreed upon by stakeholders, (or more likely litigated to conclusion at FERC) and implemented, the time frame covered by the procurement process would likely extend beyond the point in time at which these particular uncertainties would have been resolved.

Second, given the nature of the uncertainties impacting the future operation of some New York generating assets, forcing the generation owners to commit to the continued operation of their units in a three year forward auction (which could occur before these uncertainties are resolved) could lead to substantial divergence between the resources clearing in the forward procurement process and those that would be available to maintain reliability during the operating year.

Third, once implemented, the planning process used to determine capacity targets under such a forward procurement process would have the potential to systematically increase the amount of capacity procured relative to the current capacity market design, thereby increasing the cost of power out of proportion to the increase in reliability. While the New York ISO and its stakeholders could attempt to apply rules and procedures to constrain this forward planning process, it will be a planning process, not a market-based evaluation of likely future capacity requirements and costs. While the experience to date of the PJM and ISO New England forward capacity markets has been impacted by the financial crisis and their planning processes may over time evolve in a way that is better aligned with a market-based outcome, the outcomes to date do not provide a basis for presuming that the New York ISO would be able to avoid such a forward planning process-driven inflation of capacity requirements and costs under a forward capacity market design.

Fourth, maintaining some of the advantages of the current design, such as the ability to accommodate capacity resources, including imports from Hydro-Quebec, on a seasonal basis, would require a more complex design than that utilized by PJM, which would raise the on-going costs of operating such a design and require more time to develop and implement.

Fifth and finally, the current market design does not prevent load serving entities from contracting forward for capacity. A forward capacity procurement process conducted by an ISO based on its planning forecasts of future demand implements a policy that the ISO contract forward for capacity that individual consumers and load serving entities have made the decision not to contract forward to purchase. While there are theories that raise potential concerns about the adequacy of the forward contracting incentives of retail consumers and load serving entities, the implementation of a forward capacity market is not the only way to address these concerns, if and when a determination is made that some action is needed.

It needs to be kept in mind that while it is possible that the current retail access design in New York is leading to suboptimal forward contracting on behalf of power consumers, it is also possible that it is producing an optimal level of forward contracting, which happens to be lower than the level of forward contracting provided by vertically integrated utilities. It is necessary to know which situation is the case before recommending changes in the design of the New York ISO/New York PSC design in order to increase the level of forward contracting on behalf of consumers.

Hence, a decision to incur the considerable costs of implementing and then operating a forward capacity market in order to address such incentive problems should be made with due consideration of the results of an overall evaluation of the retail access design in New York, presumably by the New York Public Service Commission. This evaluation could include an assessment of whether the current retail access design is leading to an inefficiently low level of forward hedging by consumers in New York with respect to energy prices, capacity prices, both, or neither. If such a problem is identified, this evaluation could consider whether the incentive problems would be best addressed by the New York ISO contracting forward for capacity on behalf of consumers or through changes in the retail access design.

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I. Introduction

A. Overview

In this report the authors present their evaluation of a number of design elements of the New York ISO capacity market, as requested in the New York ISO's Request for Proposal (RFP) and, where appropriate, their recommendations concerning those aspects of the current capacity market design or implementation mechanisms for which changes should be considered.[11] Following this introduction, Section II of the report contains an evaluation of the New York capacity market design, with sub-sections focusing on: the role and relative importance of the type of generating unit technology used to estimate the cost of new entry (CONE); the advantages of increased reliance on energy and ancillary services market revenue to incent the supply of capacity; an assessment of the tests the New York ISO uses to apply buyer-side market power mitigation; an empirical evaluation of the slope of the demand curve used in the New York ISO capacity auctions, and a discussion of the process for creating new capacity zones.

Section III reviews and evaluates aspects of the PJM and New England capacity markets that are relevant to consideration of design changes that have been proposed for the capacity market in New York, such as a forward capacity market. Section IV continues with an assessment of whether any important market or reliability problems arise from differences in capacity market rules or seams issues among the Eastern ISOs (New York ISO, PJM and New England ISO). The report concludes, in Section V, with a detailed discussion of the advantages and disadvantages of introducing a forward capacity market in New York, taking into account the overall structure of the competitive markets administered by the New York ISO.

11 Capacity Market RFP #12-02, received April 13, 2012.

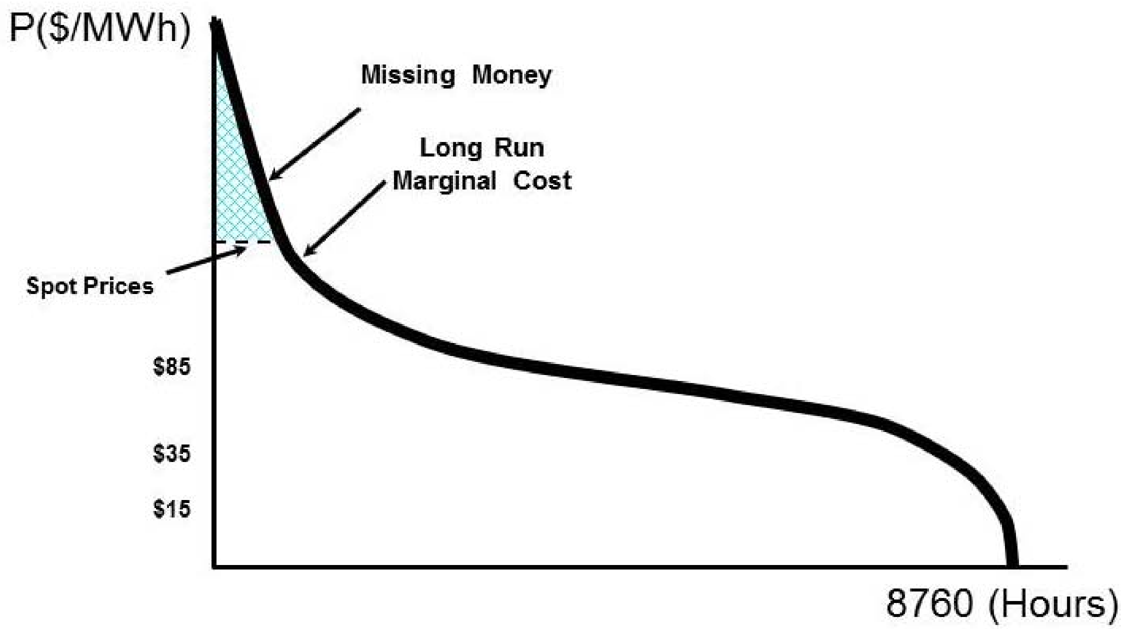
The remainder of Section I provides background for the sections which follow by discussing the purpose of capacity markets and providing an overview of the design of the New York ISO capacity market.

B. Purpose of Capacity Market

The need for a capacity market and capacity payments arises because the rules governing the determination of energy and ancillary service prices in New York, including reserve shortage prices, do not produce prices high enough, in enough hours, to recover the cost (including return of and on investment) of the capacity needed to meet peak load in the NYCA.

This situation is portrayed in Figure 1, which shows the stylized long-run incremental cost of meeting load along a hypothetical load duration curve. If the market rules do not result in prices above the line labeled "spot prices" on the left side of the load duration curve, the generating capacity needed to meet load in those hours will not recover its long-run incremental costs in spot market energy and ancillary service revenues. The level of the spot price line depends on both fuel prices and market rules, including bid caps, market power mitigation rules and shortage prices. The area above the spot price line that is cross-hatched in Figure 1 portrays the long-run incremental capacity costs that would not be recovered in spot market prices. This is what is often referred to as the "missing money."

Figure 1
A Market Price Duration Curve



In the New York ISO market design, this "missing money" is intended to be made up by capacity market revenues.[12] In an energy-only market design such as that employed by ERCOT, energy and ancillary

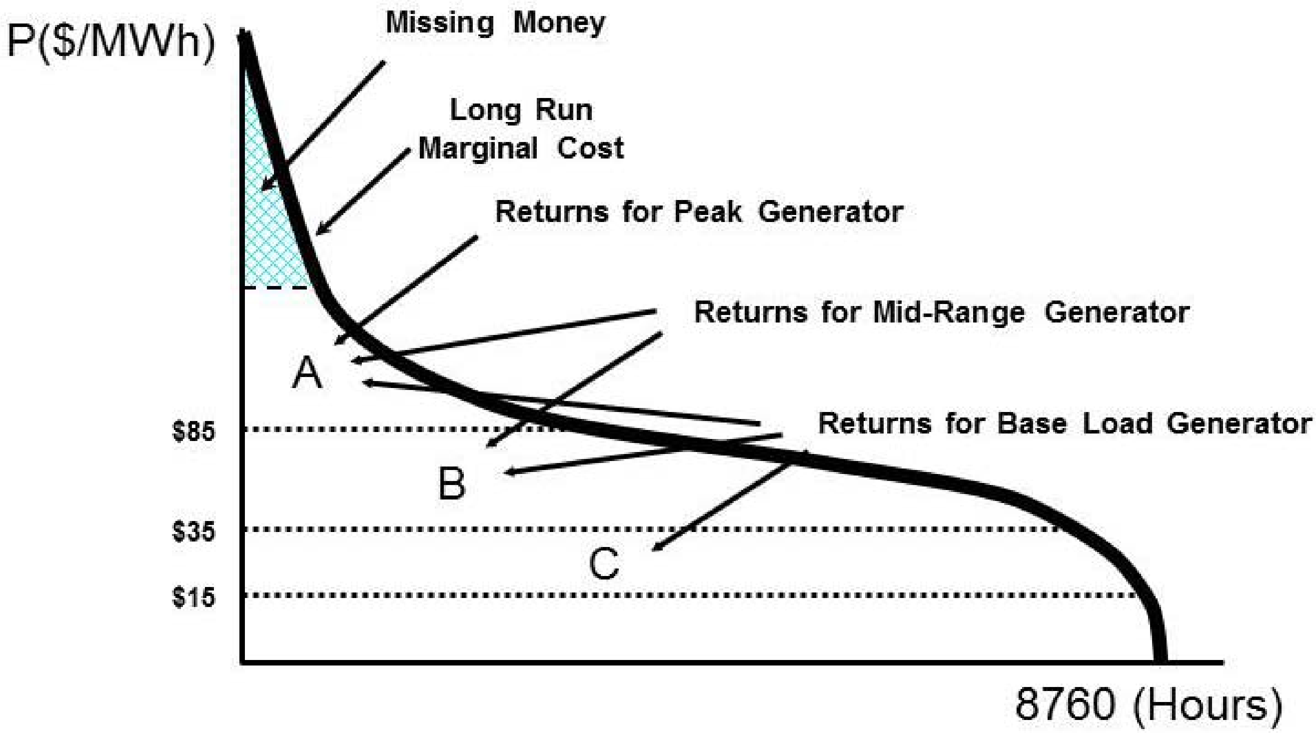
12 For merchant generators, this "missing money' means that absent the capacity market requirement it would not be profitable for them to build or keep in service the amount of capacity necessary to maintain the reliability of the New York transmission system. For individual load serving entities, this "missing money" means that absent the capacity market requirement, it would not be economic for them to build or contract for the amount of capacity needed to maintain the reliability of the New York transmission system.

service revenues need to be high enough to cover the incremental costs of all of the generation needed to meet load.

The “missing money” portrayed in Figure 1 reduces the revenues of all the generation that would have been operating during that hour, reducing the economic viability of all generating units. Figure 2 portrays the hypothetical short-run incremental costs of various types of generators, including a high incremental cost peaking generator such as a gas turbine, a mid-range generator such as a combined cycle unit, and a baseload generator, historically a coal or nuclear unit. Figure 2 shows that all of these types of generation have their revenues reduced by the missing money. Figure 2 also shows that the total returns to a peak generator are the area A, to the intermediate generator area A and B and to the baseload generator A, B, and C. The baseload generator therefore has a much larger net margin than the peak generator, but it also has much higher costs to recover in its energy and ancillary service margin.

The returns to each type of generation depend on fuel prices, the mix of existing generation and its incremental generating costs, and the shape of the demand curve.

Figure 2
Understated Settlement Prices Result in "Missing Money"



In equilibrium the returns to each type of generation being built need to be sufficient to cover its long-run costs, keeping in mind that the relevant net revenues are not just those during the current year, but those over the life of the generation asset. At any given point in time it may be the case that some types of generation do not appear to be economic and hence would not be part of the generation queue, i.e. no one would be seeking to build more units of that type. Unexpected changes in fuel costs could also increase the net revenues of some types of generation above their long-run incremental costs, until sufficient additional generation of that type is built to drive down the returns to that type of capacity, or fuel prices change again and the generation's competitive advantage disappears.

The market concept underlying the New York ISO capacity market design is for the capacity market to make up the same "missing money" for all types of generators, based on a market price for capacity set by the marginal generator, and let market participants determine which kind of generating unit will likely be the most economic source of incremental generating capacity, given expected fuel prices, generation mix, and load levels. In addition, the allocation of the capacity market costs to power consumers provides an incentive for consumers to avoid these costs by reducing their consumption during peak hours, i.e. by providing demand response.

C. Overview of Capacity Market Design in New York ISO

The New York ISO Installed Capacity (ICAP) market consists of a series of auctions to procure and assign obligations for sufficient Unforced Capacity (UCAP) to meet the reliability targets for the NYISO. The term “installed capacity” refers to the market, but the procurement and reliability requirements are based on the lower UCAP value that nets the impact of expected outages from the nominal or installed capacity.[13] Capacity suppliers offer UCAP into the New York ISO auctions and the Load Serving Entities (LSEs) have responsibility to purchase assigned minimum unforced capacity obligations.

Capacity market auctions are conducted covering each capability period for the coming year (winter and summer). Subsequent monthly spot auctions can be used to buy and sell capacity in order to adjust a party’s net position, taking into account the amounts cleared in the prior auctions for the two capability periods. Participation in the capability period and monthly auctions is voluntary; however participation in the spot auction is mandatory for load serving entities that have not covered their capacity market obligations through bilateral contracts or capacity purchases in the voluntary auctions. The spot auction utilizes a demand curve with three main parameters including a maximum price, a reference price and a zero crossing point capacity margin. The monthly spot auction demand curve parameters are adjusted to reflect changing conditions such that the average across the monthly estimates is consistent with the values used in the capability period auction.

13 New York Independent System Operator, Installed Capacity Manual Version 6.2. January 2012, p. 1-1.

The installed capacity demand curves differ by zone. Currently there are two localities within the NYISO that have locational demand curves. These are the New York City and Long Island zones. The demand curves parameters are reviewed every three years and set for the forward capability periods. However, the procurement schedule applies the established demand curves just prior to the start of the respective capability periods. Hence, while there is forward analysis of the demand curves, the forward procurement is only for the duration of the capability period.

II. Evaluation of Current New York ISO Capacity Market Design

A. Assessment of Cone Methodology

1. Introduction

This report includes a limited review of the New York ISO methodology for estimating the cost of new entry (CONE) that anchors the capacity market demand curve. The demand curves for capacity which, in conjunction with the offers of capacity suppliers, determine capacity prices in the New York ISO spot auction are based in part on the estimated annualized cost of a new entrant. At present these estimated costs are based on the projected costs of a gas turbine.

In this report we have focused on the criteria used to determine which type of capacity resource will be used to set the CONE. We have not attempted to undertake a detailed examination of all elements of the CONE calculation. While the New York ISO has historically calculated CONE based on the costs of some type of gas turbine, such a unit is not necessarily the most economic type of new unit to provide incremental generating capacity at all points in time. Depending on expected future energy prices, load shapes and regional resource characteristics, the relevant marginal capacity resource to meet firm load in a particular region might be a variety of different types of units, including combined cycles, gas turbines, and also other types of generating capacity.[14] In some regions, such as Western New York, the lowest cost source of incremental generating capacity might be provided by uprates of existing nuclear plants, wind generation, imports or incremental cogeneration capacity.

14 If firm load were stable or falling as a result of increased demand response, no new net generation would be needed to meet firm load and new capacity would need to be built only in response to the shutdown of existing generating resources.

2. Capacity Trends in New York

In assessing the type of capacity resource whose costs should anchor the capacity demand curve in the New York ISO, it is helpful to have an understanding of the types of capacity resources that have been built in the New York ISO markets in recent years. Table 41 (appended) shows the type of new generating resources that have been built in each New York load zone since the beginning of NYISO markets in 2000.[15] The new resources built in Zone J and Zone K have consisted almost entirely of gas turbines and combined cycles, with all of the gas turbines built prior to 2006. No new units of any type have been built in Zones G, H, and I, and combined cycles have been built in Zone F. Almost all of the new units built in the Western Zones A through E have been wind generation, with a few gas turbines and combustion turbines built that are either cogeneration facilities or fueled by landfill gas.

The data portrayed in Table 41 (appended) encompasses only new generating units. The table does not include all new capacity participating in the New York ISO capacity market. In particular, it does not include import capacity, increases in the capacity of existing units or demand response resources.

In addition to the capacity added by new generating units, the other major sources of increased capacity in the West have been uprates of nuclear units and capacity imports from Hydro-Quebec (imports ultimately supported by hydro generation, rather than either combined cycle or gas turbine generation units). Imports of capacity from Hydro-Quebec were 85 megawatts each month in the summer of 2008, and ranged from 0 to 125 megawatts, averaging 52.5 megawatts in the summer of 2009 (see Table 43 appended). These imports of capacity from Hydro-Quebec rose to an average of 777.5 megawatts in the summer of 2010 (ranging from 715 to 1090 megawatts), averaged 505.6 megawatts in the summer of

15 Not all of these new resources are capacity resources in New York. Because of the current design of the New York ISO capacity market deliverability requirements and the definition of capacity market zones, not all new capacity qualifies as deliverable.

2011, and averaged 396 megawatts over the first three months of the summer of 2012, despite extremely low prices for capacity located in Western New York. Because of grandfathering rules, this import capacity has been deemed deliverable while new generation in the West cannot qualify as deliverable under the current zonal design unless it acquires Capacity Resource Interconnection Service (CRIS) rights from incumbent generation that has shut down or pays for transmission upgrades that are not needed to displace existing generation resources.[16] The new capacity would not pass the deliverability test for CRIS rights because the UPNY-SENY interface would be overloaded.[17]

Nuclear capacity in New York has also increased since 2000 with uprates to Fitzpatrick and Ginna in the West, and to Indian Point 2 and 3 in the Lower Hudson Valley.[18] The added capacity at Indian Point 2 and 3 was presumably deliverable into the Lower Hudson Valley given the current capacity zone definitions. If built today, under the current deliverability rules the added capacity at Fitzpatrick and Ginna would be found not to be deliverable south of the UPNY-SENY interface, regardless of whether it could meet load in upstate New York.

Data on New York ISO capacity prices by zone since implementation of the capacity market demand curve in 2003 are compiled in Table 44 (appended). Table 44 (appended) shows that summer capacity prices in Zone J were generally in the range of 70-80 percent of the target price based on the estimated cost of a new gas turbine until 2011. These outcomes are in part an artifact of the seller market power

16 Capacity Resource Interconnection Service is the service provided by NYISO to interconnect the Developer's Large Generating Facility, Merchant Transmission Facility or Small Generating Facility larger than 2 MW to the New York State Transmission System, or to the Distribution System under Attachment Z, in accordance with the NYISO Deliverability Interconnection Standard, to enable the New York State Transmission System to deliver electric capacity from the Large Generating Facility, Small Generating Facility or Merchant Transmission Facility, pursuant to the terms of the NYISO OATT. See New York Independent System Operator, Open Access Transmission Tariff, Section 25, Attachment S: Rules to Allocate Responsibility for the Cost of New Interconnection Facilities, p. 9. at: http://www.nyiso.com/public/webdocs/documents/tariffs/oatt/oatt_attachments/att_s.pdf These rights are transferable if the generating facility with such interconnection rights ceases operation., see New York Independent System Operator, Open Access Transmission Tariff, Section 25.9.6

17 The UPNY–SENY interface is a closed interface that corresponds to the boundary between load zones E and F and load zone G. Among the lines comprising the interface is Leeds-Pleasant Valley which is frequently binding in real-time operations.

18 A recent uprate to the capacity of the nine mile unit is not yet reflected in the Gold Book data used to compile Table 41 (appended).

mitigation rules, including the terms of the original generation divestiture agreements. Most of the generation built in Zone J since 2003 has been built by load serving entities or by entities contracting with load serving entities for the resource's output rather than by entities selling their output and capacity on the spot market, so it is difficult to assess the extent to which expected capacity prices have been sufficient to support the entry of new combustion turbines based on the historical entry data alone. The recent entry of the Bayonne Energy Center on a merchant basis provides one data point indicating that entry can be economic even if capacity prices are expected to be less than the reference price.

Table 44 also shows that capacity prices have consistently been very low in upstate New York. The low level of capacity prices, at most a small a fraction of the estimated CONE based on the cost of a gas turbine, in part reflects the declining power demand in Western New York, and hence a declining need for capacity in that region, as well as the fact that some incremental capacity has been available at low cost from sources other than combined cycles and combustion turbines. In the last few years, the current New York ISO deliverability requirements for capacity, in combination with the current capacity zone boundaries, have prevented new generation built in Western New York from qualifying as deliverable in the NYCA zones because it would not be deliverable south of the UPNY–SENY interface into the Lower Hudson Valley Zones, G, H, and I. As a result of this deliverability requirement, new capacity cannot participate in the capacity market unless it acquires CRIS rights from incumbent generation that ceases operation or pays for the construction of additional transmission capacity to serve load in the Lower Hudson Valley (i.e. a System Deliverability Upgrade), transmission capacity that would be completely unnecessary from the standpoint of meeting load in Western New York or displacing existing generation in Western New York.

Given the amount of existing generation that has shut down in Western New York, there may have been a significant amount of CRIS rights available for transfer to new generation resources located in Western New York which would have enabled new generation resources to acquire the CRIS rights and participate in the capacity market. As noted above, capacity imports from Hydro-Quebec, which contribute to the capacity surplus and low capacity prices in upstate New York, have been grandfathered as deliverable up to 1090 megawatts without regard to the deliverability test imposed on new generators in Western New York and these imports have increased in recent years as shown in Table 43 (appended). Demand response is also allowed to participate in the capacity market without passing a deliverability test, so increases in Special Case Resources (SCR) clearing in the capacity market in Western New York through the summer of 2010 have also tended to keep Western capacity prices low.

3. Type of Resource Used to Anchor Demand Curve

The New York ISO Market Services Tariff defines a peaking unit for the purpose of defining the capacity market demand curve as a unit with the technology that results in the lowest fixed costs and highest variable costs among all other units' technology that are economically viable.[19] While one can in the abstract conceptualize such a high incremental energy cost, low capacity cost peaking unit as a benchmark of the cost of pure capacity, such a resource would not necessarily be the lowest cost source of incremental capacity at any particular point in time. If the abstract costs of such a hypothetical resource do not correspond to the margins that would be earned by the kind of capacity that actually could and is being built, those abstract costs will not provide a completely accurate measure of the competitive cost and price of incremental capacity. As discussed in Section IID below, however, such mismeasurement will not lead to large reductions in consumer welfare (the difference between the value and cost of the capacity) if the demand curve slope provides a reasonably accurate measure of the value of incremental capacity. On the other hand, such mismeasurement could lead to larger reductions in consumer welfare if the demand curve is materially flatter than warranted by the reliability value of incremental capacity.

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19 New York Independent System Operator, Market Services Tariff, Section 5.14.1.2

There is no “correct” solution to the problem of defining the resource whose estimated costs will be used to set CONE and anchor the demand curve. The issue is not that the New York ISO’s Service Tariff has failed to articulate a known methodology that would always identify the correct resource type whose costs should set CONE. There is no such methodology. While in long-run equilibrium all investments in new capacity would be expected to yield their required return, capital investments in generating capacity are long-lived, so the market is never in long-run equilibrium. In practice, investments in different types of capacity will turn out over time to yield more or less than their required return and surpluses of particular types of capacity can persist for long periods of time.

At any point in time, the identity of the type of unit that is potentially on the margin as a source of incremental generating capacity depends on a number of factors, most or all of which can change over time. Differences in energy and ancillary service margins can alter the type of incremental capacity that is most economic at any point in time, and the size of these margins will vary with the level of gas and coal prices, as well as with changes in the resource mix or congestion patterns which change the type of unit that is on the margin in the real-time energy market. Moreover, if the rate of growth of peak load is low or negative, the cost of capacity supplied by new resources may have no relationship to the competitive price of capacity, which could be set by the going-forward costs of existing capacity or low cost capacity additions to existing resources.

Using the type of capacity resources that are in the generation interconnection queue to determine the kind of resource which would set CONE would be another approach, but it would have a logical circularity that would invite anomalous outcomes. This would be a particular concern if little or no new capacity were provided by new resources so the type of resource in the interconnection queue used to determine CONE might be determined by a single unit whose construction was incented by special factors unique to the resource or location and have little relationship to the type of unit that would generally be the lowest cost source of marginal capacity.

It would also be problematic to use the costs of demand resources to set CONE because the relevant cost of demand response includes both the demand response provider communications and infrastructure costs and the marginal value of the foregone power consumption (by the power consumer providing the demand response), which is both customer specific and difficult for an ISO to estimate.

When the “Missing Money” is made up in a capacity market, it is essential to allow demand response to participate in capacity markets to ensure that power consumers do not incur the cost of building and maintaining capacity that costs more than the value of the load it serves. The “Missing Money” made up in the capacity market is a “missing cost” in the energy market for power consumed during shortage hours, so this cost needs to be reflected in power consumer consumption decisions. Incorporating demand response in capacity markets is important to achieving efficient outcomes in regions such as New York that rely upon capacity markets to maintain resource adequacy. However, while demand response is an important participant in capacity markets, neither the “cost” nor the offer price of demand response resources in capacity markets provide an appropriate exogenous measure of the long-run cost of the capacity used to meet firm load.

Consider, for example, if in addition to the current level of demand response there were 1000 megawatts of load in New York that would reduce its consumption to zero if the real-time price rose to $500 per megawatt hour. How would this change the capacity market in New York and how would it change the definition of the demand curve? First, the existence of this additional price responsive load would not change the need of the New York ISO to have enough capacity available to meet the remaining load on the system, i.e. the firm load that would not reduce its consumption to zero when the real-time price rose above $500 per megawatt hour.

Second, in order to meet the firm load, the sum of energy, ancillary service, and capacity market revenues would need to be high enough to cover the costs of the generation needed to meet this firm load. The $500 per megawatt hour price at which some consumers reduced their consumption would not be relevant to the cost of the generation needed to meet firm load.

Third, it is possible that with this quantity of price responsive load in the New York ISO market, energy and ancillary service prices would be high enough to support the level of capacity needed to meet the remaining firm load without a capacity market payment. How would the New York ISO determine this? It would need to compare the projected energy and ancillary service revenues to the cost of incremental generation. If the energy and ancillary service revenues were sufficient to cover the costs of the generation needed to meet firm load, then the capacity payment would be zero. The anchor of the demand curve would still be based on the cost of generation, not the $500 price at which price responsive load reduced its consumption, because it is the firm load that does not reduce its consumption that the capacity would be needed to meet.

It is for this reason that even in the ERCOT energy only market, the market monitor evaluates the adequacy of energy prices to maintain reliability by comparing energy and ancillary service revenues to the cost of generation, not to the price at which some load reduces its consumption, because it is the load of the consumers that will not reduce their consumption that needs to be met and this load must be met with generation.[20]

The New York ISO has long included demand response resources in its capacity market through Special Case Resources.[21] The participation of demand response resources in the New York ISO capacity market

20 See Potomac Economics Ltd, 2011 State of the Market Report for the ERCOT Wholesale Electricity Markets, July 2012 pp. 75-79.

21 New York Independent System Operator, Installed Capacity Manual, Version 4.2. December 4, 2003, Section 4.12.

in effect allows the NYISO to procure only the amount of physical generating capacity needed to meet firm load, i.e. consumption that will not be curtailed in response to high prices or New York ISO instructions. Demand response resources can be used to meet peak forecasted load but cannot, however, be used to meet peak forecasted firm load, because by definition firm load is the load that must be met after the load of Special Case Resources and other demand response is off the system. Only physical generating resources can be used to meet the load that remains after demand response resources have been activated and have reduced their power consumption.

Demand response resources supplying capacity in the New York ISO markets have an important impact on the clearing price in the various New York ISO auctions. Because demand response resources can participate in the capacity market and its auctions, the price of capacity, and payments to physical generating resources, cannot and should not rise above the value of that capacity to power consumers, i.e. the value of power to the potential demand response resource or the cost of curtailing consumption. However, the cost of demand response is neither equal to the value of power to any particular customer, nor equal to the cost of any particular type of curtailment, but equals the communications and infrastructure cost of the demand response provider, plus the expected value of foregone power consumption to whichever demand response resource is marginal in the capacity market auction at a particular point in time, (net of avoided energy market costs and any energy market payments for reductions in consumption) which is not known prior to the auction.

While there is a communications and settlement infrastructure cost to providing demand response, just as there are such costs to interconnecting physical generation, the bulk of the cost of providing demand response is the value of the power consumption that must be reduced to provide the demand response, and there is no stable measure of this cost. The value of power depends on the characteristics of the individual power consumer called upon to reduce consumption, and, on the probability of being called upon,[22] which in turn depends on the mix and quantity of demand response, physical generation and intermittent generation. The value of this forgone consumption is the marginal value of expected lost load to the consumer providing demand response. While this value could in principle be estimated for individual power consumers, there would be a large margin of error. Moreover, each power consumer would have its own marginal value, so these estimates would measure a range of marginal values of expected lost load from high to low, rather than a single value that could be used to anchor the capacity market demand curve.[23] While generator resources such as combined cycles and combustion turbines also have unique site specific costs that impact the actual cost of new entry of such resources, those unique site specific factors make up only a limited portion of the overall estimated cost of new entry. In the case of demand response resources used to measure the cost of new capacity, virtually all of the costs of reducing consumption are customer specific, the only material generic costs are the almost incidental administration and metering costs.

It is also important in considering the possibility of using the cost of demand response to set the reference price for the capacity market demand curve to recognize that the reference price of the demand curve must reflect that cost at which additional demand response capacity will be available, not the cost of existing demand response capacity. Thus, if an effort were made to anchor the capacity market demand curve based on the estimated cost of incremental demand response, it would not be a matter of measuring

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22 A capacity market pays a demand resource a fixed payment for being willing to interrupt load, often up to a specified number of times or hours over the period. If a resource expects to rarely be called because of a previously existing surplus of physical generating capacity, the expected value of the interrupted load will be lower because few interruptions would be expected. If the resource balance were very tight, so that a demand response resource would anticipate being interrupted frequently, perhaps up to a cap, the expected value of the interrupted load would be higher.

23 If the New York ISO were given authority to compel Responsible Interface Parties to provide it with data reflecting their payments to power consumers providing demand response and with measures of the other costs[23] of the Responsible Interface Parties, the New York ISO could use these data to compile an index of demand response costs. However, this index would simply reflect the current expected capacity price. It would not inform the New York ISO as to how much more demand response would be available at a somewhat higher capacity price or how much less would be available at a lower price. If the capacity price rose, the index would rise, if the capacity price fell, the index would fall.

the value of power to consumers already providing demand response but of measuring the value of power and cost of interruption to consumers who do not provide demand response.

The estimated cost of new entry for generating capacity is, as we discuss below, must be recognized to be a necessarily imperfect measure of the actual price at which at elastic supply of capacity would be available from new generating resources. While imperfect, this is what the cost of new entry attempts to measure. It does not measure the price at which a small amount of incremental capacity will be available from low cost additions to existing capacity resources. If the cost of demand response were to be used to anchor the capacity market demand curve, the demand response supply price used for this purpose would need to similarly measure the price at which an elastic supply of capacity would be available from new demand response resources. We do not believe that there is any such price at which the supply of demand response becomes very elastic, on the contrary the cost of providing demand response is intrinsically customer specific and different customers will be willing to reduce power consumption by different amounts at different prices. Moreover, while on can perhaps imagine a standardized demand response such as a backup generator, the actual historical supply of Special Case Resources does not provide any basis for concluding that there is a price elastic supply of this form of demand response at prices materially below the estimated cost of entry for new generation.

Hence, we do not see any basis for assuming there is some price at which a substantial amount of demand response would be available and are not familiar with any empirical studies of demand response that suggest the existence of such a price. If the capacity demand curve is capped at a price at which new generating capacity will not be forthcoming and the supply of demand response at this price is limited, this would inevitably result in a shortfall in the capacity needed to maintain reliability, a shortfall which would have to be addressed through non-market means. In fact, such a design would ensure that reliability needs would have to be met through non-market mechanisms, because the capacity price could not rise to the level needed to support investment in new generation to meet firm load.

Moreover, we do not see how the cost of demand response could be used to define “a price” that could be used to anchor the demand curve, rather different amounts of demand response would be available at a whole range of prices and which would be marginal would depend on where the capacity market clears.

Indeed, the recent contracting decisions of New York load serving entities shows that they do not believe that material quantities of demand response would be available in Zone J for less than the reference price as it would have been highly inefficient to contract for the new combined cycle capacity if those capacity needs could have been met through lower cost procurement of demand response.

Hence, while we agree that the price of capacity should reflect the marginal value of capacity to consumers, we believe that by defining the capacity market demand curve based on the reliability value of incremental generating capacity, the New York ISO capacity market design will support this goal. We do not, however, see any basis for anticipating that this objective would be served by attempting to anchor “the price” of the target level of capacity based on the assumed costs of a hypothetical generic demand response resource, when there is in reality a range of consumers who would offer to reduce consumption at a wide range of prices, and none of these reductions could be used to meet firm load.

Hence there is no well-defined exogenous cost of demand response that can be measured in advance and used as a superior benchmark for the long-run cost of capacity in New York ISO markets. While imperfect, the estimated long-run cost of physical generation used to meet firm load is a more reliable long-run benchmark for the capacity market demand curve than would be the estimated value of power to a particular demand response resource.

Table 41 (appended) based on Gold Book data covering generating units that went on-line prior to April 1, 2012 shows that until very recently, virtually all of the new generating units built and capacity added east of the Central East interface in New York since 2005 has been in the form of combined cycle units. Hence, the use of the cost of a new combined cycle unit to define CONE may have been appropriate for this past period. This may or may not continue to be the case over the next few years. Not only does the construction of combined cycle units replacing older less efficient gas fired steam generation, change the dispatch stack and reduce the profitability of building more combined cycle units, the fall in gas prices over the past two years has also reduced the cost advantage of new combined cycle units relative to existing capacity and hence will reduce their real-world net energy revenues going forward. The Bayonne Energy Center which went on-line since April 1, 2012 consists of gas turbines.

There is less basis for selecting any particular kind of unit to set CONE for capacity located in load zones west of Central East in which total generating capacity has been falling. New capacity located in these zones has generally been wind, nuclear upgrades or hydro based import capacity (as shown in Table 41 appended), and capacity prices have been set by the demand curve, and indirectly by the price required to keep existing capacity in operation, rather than by the cost of new generating capacity.[24] Capacity market prices in the rest of state capacity zone may have fallen below even going-forward costs of a combustion turbine or combined cycle in the West at times over 2011-2012.[25] Most of the capacity that will remain in operation in the West likely has lower incremental energy costs and larger short-run margins than any of the gas fired generation considered for use in setting CONE.

The capacity price for the NYCA zone (upstate New York) has been far below the estimated CONE for this region (based on a combustion turbine) for a decade. It is inappropriate to describe these price levels as reflecting a short-run disequilibrium when they have prevailed for a decade, but these prices also do not reflect a long-run equilibrium. Higher capacity prices will be required in the long-run to support the

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24 In fact, the deliverability test has in recent years prevented any new generation built in the West from providing capacity in the capacity market without acquiring CRIS rights from incumbent generators or building unnecessary transmission.

25 There are also resources fueled by landfill gas but they have different economics than a conventional gas turbine.

level of capacity needed to meet Western power demand. But given the existing generation stock, the long-run may be a very long time absent some shock that makes continued operation of a significant proportion of the existing generation stock uneconomic. The continued low capacity prices in Western New York likely reflect little or no demand growth, the lack of need for the type of unit used to set CONE, and likely the availability of grandfathered import supply from Hydro-Quebec. If wind generation is backed out, Western generating capacity (Zones A through E) declined between 2000 and 2011. The only substantial generating capacity built upstate over this period were combined cycles built in Zone F, the Albany area.[26]

The cheapest source of capacity net of energy market revenues is not immutable but will depend on the shape of the load curve and the costs of the marginal units over the hours of the year. If there is a lot of generation with high incremental costs in the market, a new combined cycle might be the cheapest incremental source of capacity. As noted above, however, the fall in gas prices over the past couple of years has reduced the expected net energy revenues from the construction of a combined cycle. While continuing to limit the resource considered for anchoring the demand curve to a combustion turbine would reduce the costs to the New York ISO of the triennial demand curve reset process, there would be a potential for the demand curve determined in this way to be out of line with actual market outcomes if gas prices rise and the net cost of a combined cycle would be materially lower than a combustion turbine.

In this context, another factor that is relevant to the anchoring of the demand curve and several other topics discussed below in this report is that while in our view the estimated net CONE used to anchor the demand curve should be based on a reasonable methodology, even if the CONE calculation is based on the lowest cost source of incremental generating capacity, the calculated CONE will not necessarily accurately measure the incremental cost of generating capacity. This needs to be kept in mind in

26 Zone F is east of Central East so generation located in this zone is paid eastern reserve prices and Zone F net load has the largest shift factor on Central East so has the highest energy prices when Central East is the binding transmission constraint.

assessing how much resources the New York ISO and its stakeholder's should invest in trying to better identify the type of resource that will provide marginal generating capacity at any point in time for the purpose of anchoring the demand curve.

Five factors likely to contribute to differences between the estimated CONE and the actual incremental cost of new capacity are, first, the way CONE is estimated presumes that incremental generating capacity will be provided through the construction of new units, rather than through upgrades to the capability of existing units. This is not necessarily the case. In the U.S. oil refining industry no new fuels type refineries have been built since the 1980's but refining capacity and transportation fuels production capacity continued to rise until recently through expansions and debottlenecking of existing capacity. A similar pattern is clearly evident in the U.S. electricity industry with respect to the growth of nuclear generating capacity over the past 15 years.[27]

Second, the estimated net CONE used to anchor the demand curve may be based on estimates of energy and ancillary service net revenues that differ from the expectations of new entrants (or those of incumbents adding incremental capacity). These differences could reflect either different expectations regarding the likely future level of these revenues for the capacity market region as a whole or differences in expected net energy and ancillary service revenues that are specific to the plant location. In Section IIB4 below we discuss some limitations of the current methodology used to estimate energy and ancillary service revenues. We also note in Section IIB below that the tariff requires that these revenues be estimated in a way that can cause them to materially differ from the revenues expected by a rational market participant. Beyond these observations, this conclusion reflects our view that any time a projection of future market prices and net revenues is reduced to a formula for regulatory purposes, it will at times fail to accurately measure expected future market conditions.

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27 See, for example, Lucas W. Davis and Catherine Wolfram, "Deregulation, Consolidation, and Efficiency: Evidence from U.S. Nuclear Power", Energy Institute at HAAS WP #127, August 2011 .

Third, the assumptions regarding cost of equity capital and debt and the time path for recovery of the investment used to develop CONE may differ from the actual cost of equity capital and debt or projected timing of the return of investment for either new entrants or incumbent firms.

Fourth, the estimates of construction costs and equipment costs may at times fail to accurately measure the costs of actually buying this equipment or constructing the capacity resource. During boom times, conventional cost estimates may understate the costs given delivery queues and various terms involved in acquiring equipment, while during times of low generating margins like today, those ready and willing to contract for new equipment and move forward with construction may be able to negotiate better prices than those quoted.

Fifth, expectations regarding the future levels of capacity prices that differ from those implicitly built into the derivation of the one year cost of new entry, can have a major impact on the capacity price at which competitive entry would occur.

4. Conclusions

Recognizing the impossibility of choosing any methodology for setting CONE that will always accurately identify the most appropriate resource type for use in anchoring the capacity market demand curve, the best candidates are to use combined cycle or combustion turbine costs for the zones east of Central East. Combined cycles have in practice been the predominant type of unit that has been constructed in that region since 2000, but the balance of the economics may change if gas prices remain low, and new capacity construction may shift to favoring gas turbines in some or all of these zones.

There is no resource type whose construction costs would have accurately benchmarked the market price of capacity in the Western zones over the past decade. While the extremely depressed capacity prices in Western New York over the past few years will likely speed the exit of some surplus capacity, and exports of capacity to PJM and New England likely tighten the market at some point in the next few years, it does not appear likely that market conditions in the West will shift in the foreseeable future to the point that construction of new combined cycle plants would be economic unless there is some shock that forces a material amount of the existing generation out of the market. Overall, however, the net costs of a combined cycle could potentially provide a better measure of the costs of capacity that would be built in the West than would the net capacity costs of gas turbine as long as Western New York remains a generation pocket as a result of congestion on Central East or Leeds-Pleasant Valley.

The use of a combined cycle rather than gas turbine to anchor the capacity demand curve would make it more important to accurately estimate the prices used to project expected energy and ancillary service revenues. Hence, it would be essential to address the issues arising from using only three years of data to estimate these revenues and the need to potentially project revenues outside the range of the data used for the estimation as discussed in Section II B 4 below. Use of a combined cycle to anchor the demand curve will also tend to make total net revenues decline more steeply with increases in capacity (for the reasons related to the operation of Section 5.14.1.2 of the tariff as also discussed in Section IIB4 below), which will need to be taken into account in setting the demand curve for the capacity payment component of these net revenues. Finally, use of a combined cycle rather than gas turbine to anchor the capacity market demand curve will require taking account of the difference in the scale of efficient entry in setting the parameters of the capacity payment demand curve.

If the costs and revenues of a combined cycle, rather than gas turbine, or a complex containing more than two gas turbines, were used to set net CONE for Zone J or Zone K, it would also be necessary to more explicitly account for the scale impact of entry in setting the estimated value of net CONE and in the pricing rules associated with net CONE. Since new capacity in Zones J, K and F since 2005 has in fact largely taken the form of combined cycles, this entry has impacted prices more than would a two combustion turbine complex, but these units have presumably in practice had a lower net CONE than the combustion turbines used to anchor the demand curve. If the estimated net CONE of a combined cycle were used to set CONE, the scale impact of entry would need to be better accounted for in the CONE calculation. We do not discuss these kind of adjustments to CONE in this report as this is an appropriate topic for discussion the next reset of the CONE. We will, however, return to the topic of the impact of scale economies and entry in the context of buyer-side market power mitigation in Subsection C below. We also do not make a definite recommendation regarding the use of combined cycle as an alternative to gas turbine costs to anchor the capacity market demand curve because the appropriateness of such a change depends on whether changes are also made in the way energy and ancillary service revenues are estimated.

B. Assessment of the Adjustment for Net Energy Revenues in the New York ISO Capacity Market

This section addresses five topics. First, we discuss the relative importance of energy and capacity market revenues in incenting investment in generation capacity in New York. Second, we discuss the advantages and disadvantages of increasing the role of energy market revenues in incenting generation investment and performance. Third, we discuss the difficulty of increasing reliance on energy market revenues and demand response within the current capacity market design, and how these difficulties are in part, a result of certain features of the current reserve shortage pricing design. Finally, we review the methods used to calculate the projected energy and ancillary service revenues that are used to adjust CONE for net energy market revenues.

1. Role of Energy Market and Capacity Market Revenues in New York

Table 3 portrays the ratio of the projected net energy and ancillary service revenues to the sum of these net revenues and the spot auction capacity payments over the May 2007-April 2009 period, more or less pre-financial crisis, and May 2010 to April 2012 period, post crisis. Table 3 shows that over the last two years generation in New York City was projected to earn nearly half its overall margin in the energy and ancillary service markets while generation located on Long Island or upstate New York was projected to earn almost its entire margin in the energy market.

Table 3
Average ICAP Spot Prices and Net Energy Revenues
(thousands of dollars per megawatt year)

	2007-2009			2010-2012		
	NY City	Long Island	NYCA	NY City	Long Island	NYCA
Average ICAP Spot Price	$72.80	$46.57	$27.65	$87.31	$8.80	$7.60
Average Forecast Net Energy Revenues	$ 57.91	$ 65.15	$14.76	$88.54	$136.67	$19.16
Total	$130.71	$111.71	$42.41	$175.84	$145.46	$26.76
Percent Energy	44.3%	58.3%	34.8%	50.4%	94.0%	71.6%

Sources
(1) Average ICAP Spot Price was taken from Table 44 (appended).
(2) Average Energy Revenues for 2007/2008-2010/2011 taken from:
http://www.nyiso.com/public/webdocs/products/icap/2011-2014_demand_curve_reset/Demand_Curve_Model_03_29_11_NYC_cc1.xls
(3) Average Energy Revenues for 2011/2012 taken from:
http://www.nyiso.com/public/webdocs/committees/bic_icapwg/meeting_materials/2010-11-09/NYISO_demand_curve_recommendations_10_30_2010_clean.pdf

This pattern is a result in considerable part of the depressed capacity prices associated with the decline in demand and demand growth following the financial crisis. If the projected net energy and ancillary service revenues are compared to capacity prices over the May 2007 to April 2009 period, capacity payments are much more important in all three regions than they were over the 2010-2012 period.

Net energy and ancillary service revenues were in practice less significant than suggested by Table 3 over the 2010-2012 period because the projected energy and ancillary services revenues are greatly overstated, likely also because of the decline in demand and demand growth following the financial crisis which was not anticipated when the net energy and ancillary service revenues were projected. Table 4 shows the projected net energy and ancillary services revenues used to calculate the offset for the determination of net CONE.

Table 4
NYISO Capacity Market Net Energy Revenue Offset
(thousands of dollars per megawatt year)

ICAP Auction	NYCA	NYC	LI
2005/2006	$19.00	$48.00	$38.00
2006/2007	$19.57	$49.44	$39.14
2007/2008	$20.16	$50.92	$40.31
2008/2009	$9.36	$64.89	$89.98
2009/2010	$10.09	$69.95	$97.00
2010/2011	$10.87	$75.41	$104.56
2011/2012	$27.44	$101.67	$168.77
2012/2013	$27.91	$103.39	$171.64
2013/2014	$28.39	$105.15	$174.55

Sources:

1. 2005/2006 - 2010/2011 from http://www.nyiso.com/public/webdocs/products/icap/2011-2014_demand_curve_reset/Demand_Curve_Model_03_29_11_NYC_cc1.xls

2. 2011/2012 - 2013/2014 from http://www.nyiso.com/public/webdocs/committees/bic_icapwg/meeting_materials/2010-11-09/NYISO_demand_curve_recommendations_10_30_2010_clean.pdf

Table 5 on the other hand shows the estimated margins for a gas turbine (and combined cycle) as calculated by Potomac Economics based on actual energy and ancillary service prices. The hypothetical net energy revenues calculated based on actual prices over the years 2009, 2010 and 2011 were about half the projected net revenues for a gas turbine located on Long Island assumed in setting the net CONE, a bit less than half those assumed for a unit located in Zone J, and less than a fifth of those assumed for a gas turbine located in Western New York.

Table 5
NYISO Net Energy & Ancillary Services Net Revenue from State of the Market Reports
(thousands of dollars per megawatt year)

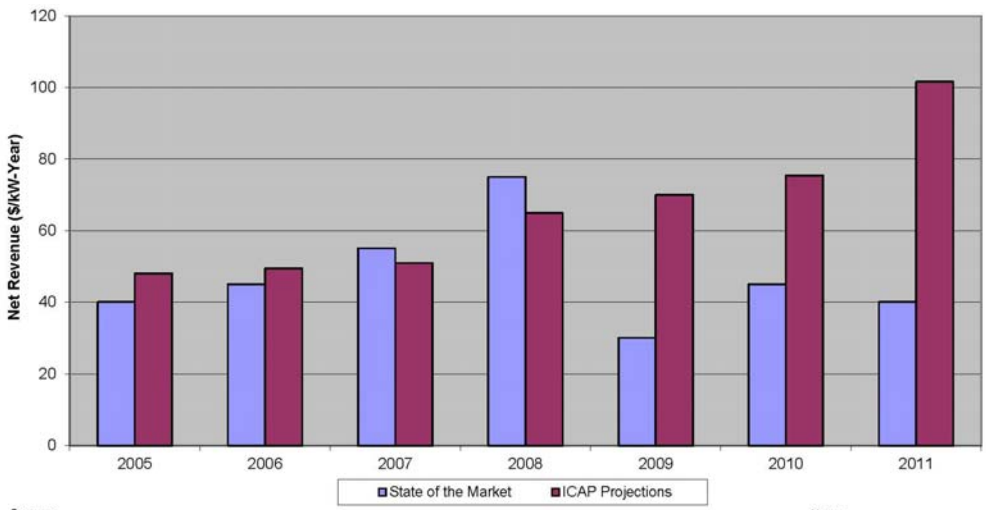
	Capital Region-Zone F		NYC		LI		Hudson Valley		West	
ICAP Auction	Combined Cycle	Gas Turbine	Combined Cycle	Gas Turbine	Combined Cycle	Gas Turbine	Combined Cycle	Gas Turbine	Combined Cycle	Gas Turbine
2005	105	5	185	40	250	60	115	15	N/A	N/A
2006	90	5	160	45	280	100	115	25	N/A	N/A
2007	90	20	105	55	210	110	105	50	20	15
2008	105	25	150	75	220	120	125	65	15	15
2009	45	5	55	30	100	55	50	25	5	5
2010	70	5	90	45	150	80	85	40	25	5
2011	65	10	90	40	170	95	85	35	20	5

Sources:
1. 2005-2006 estimated based on Figures 9 and 10 from
www.nyiso.com/public/webdocs/documents/market_advisor_reports/2006/2006_state_of_market_report.pdf

2. 2007 - 2011 estimated based on Figures A-10 and A-11 from
www.nyiso.com/public/webdocs/documents/market_advisor_reports/2011/SOM_Report-Final_41812.pdf

Figures 6, 7, and 8 compare the actual and projected energy and ancillary service margins for a new combustion turbine in Zone J, Zone K, and upstate New York.

Figure 6
Forecasted and Actual Net Energy Revenues for Proxy Combustion Turbine in New York City

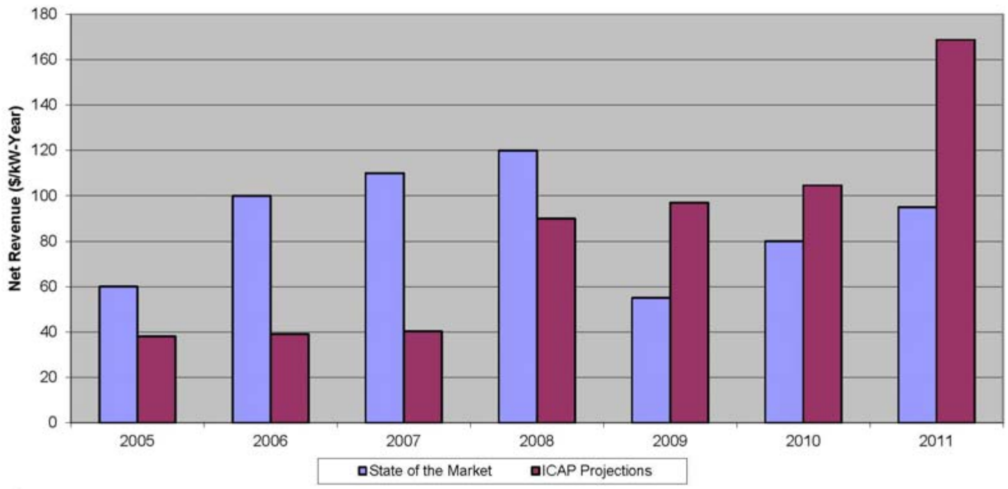


Sources:
1. 2005-2006 Actual Net Revenue estimated based on Figures 9 and 10 from www.nyiso.com/public/webdocs/documents/market_advisor_reports/2006/2006_state_of_market_report.pdf
2. 2007-2011 Actual Net Revenue estimated based on Figures A-10 and A-11 from www.nyiso.com/public/webdocs/documents/market_advisor_reports/2011/SOM_report-Final_41812.pdf
3. 2005-2010 Projected Net Revenue from http://www.nyiso.com/public/webdocs/products/icap/2011-2014_demand_curve_reset/Demand_Curve_Model_03_29_11_NYC_cc1.xls
4. 2011 Projected Net Revenue from http://www.nyiso.com/public/webdocs/committees/bic_icapwg/meeting_materials/2010-11-09/NYISO_demand_curve_recommendations_10_30_2010_clean.pdf

Notes:
1. Actual Net Revenue is based on the calendar year while Projected Net Revenue is based on the Capability year (May 1-April 30).
2. Actual Net Revenue is based on estimates for a Gas Turbine.

Figure 6 shows that the projected net energy market revenues used to calculate Net CONE for New York City were reasonably close to the revenues estimated by the independent Market Monitoring unit over the period 2005-2008, despite very large unanticipated increases in fuel prices. This was not the case over the period 2009-2011 over which the projected net energy revenues greatly exceeded the potential net revenues of such a unit as estimated by the independent Market Monitoring unit.

Figure 7
Forecasted and Actual Energy Revenues for Proxy Combustion Turbine on Long Island

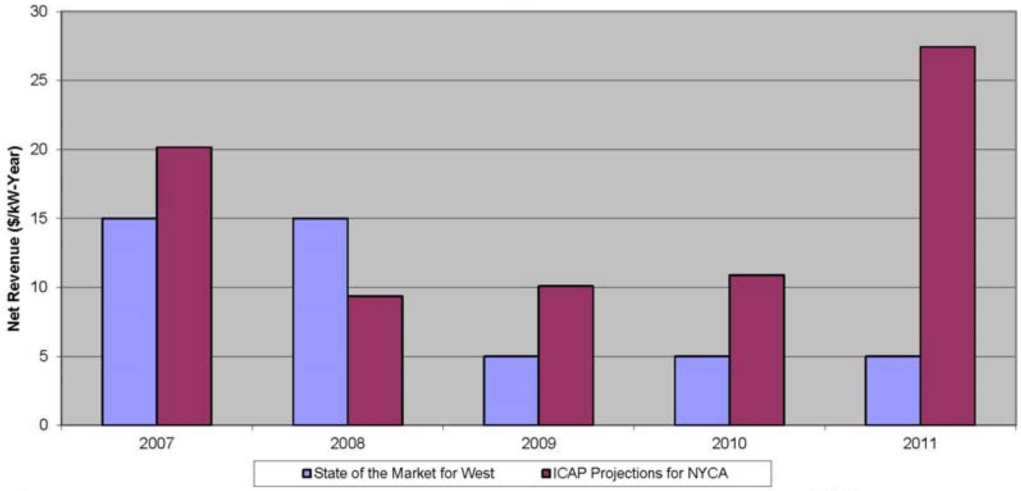


Sources:
1. 2005-2006 Actual Net Revenue estimated based on Figures 9 and 10 from www.nyiso.com/public/webdocs/documents/market_advisor_reports/2006/2006_state_of_market_report.pdf
2. 2007-2011 Actual Net Revenue estimated based on Figures A-10 and A-11 from www.nyiso.com/public/webdocs/documents/market_advisor_reports/2011/SOM_report-Final_41812.pdf
3. 2005-2010 Projected Net Revenue from http://www.nyiso.com/public/webdocs/products/icap/2011-2014_demand_curve_reset/Demand_Curve_Model_03_29_11_NYC_cc1.xls
4. 2011 Projected Net Revenue from http://www.nyiso.com/public/webdocs/committees/bic_icapwg/meeting_materials/2010-11-09/NYISO_demand_curve_recommendations_10_30_2010_clean.pdf

Notes:
1. Actual Net Revenue is based on the calendar year while Projected Net Revenue is based on the Capability year (May 1-April 30).
2. Actual Net Revenu is based on estimates for a Gas Turbine.

Figure 7 shows that the net revenue projections used to anchor the Long Island capacity market demand curve were consistently lower than the actual net energy and ancillary service revenues over the period 2005-2008, particularly in 2006 and 2007. This could be a result of the higher than expected gas prices during this period. However, this pattern also reverses over the 2009-2011 period with projected revenues exceeding the potential revenues estimated by the market monitor, with a particularly large difference in 2011.

Figure 8
Forecasted and Actual Energy Revenues for Proxy Combustion Turbine in West



Sources:
1. 2005-2006 Actual Net Revenue estimated based on Figures 9 and 10 from www.nyiso.com/public/webdocs/documents/market_advisor_reports/2006/2006_state_of_market_report.pdf
2. 2007-2011 Actual Net Revenue estimated based on Figures A-10 and A-11 from www.nyiso.com/public/webdocs/documents/market_advisor_reports/2011/SOM_report-Final_41812.pdf
3. 2005-2010 Projected Net Revenue from http://www.nyiso.com/public/webdocs/products/icap/2011-2014_demand_curve_reset/Demand_Curve_Model_03_29_11_NYC_cc1.xls
4. 2011 Projected Net Revenue from http://www.nyiso.com/public/webdocs/committees/bic_icapwg/meeting_materials/2010-11-09/NYISO_demand_curve_recommendations_10_30_2010_clean.pdf

Notes:
1. Actual Net Revenue is based on the calendar year while Projected Net Revenue is based on the Capability year (May 1-April 30).
2. Actual Net Revenue is based on estimates for a Gas Turbine.

Figure 8 shows a similar very large gap between the projected net revenues used to anchor the NYCA demand curve and the potential net revenues estimated by the Independent Market Monitor for 2011.

Based on actual market prices, the estimated contribution of energy and ancillary service market revenues to the cost recovery of a hypothetical gas turbine in upstate New York was minimal in 2011, and the hypothetical net energy market revenues were only around 25 percent of the total cost recovery in Zone J. Only on Long Island would the net energy and ancillary service revenues estimated based on actual prices have been material to resource viability.

2. Advantages of Increased Importance of Energy and Ancillary Service Market Revenues

The New York ISO has requested as part of this report an assessment of "whether increased scarcity pricing would provide better overall market signals than the capacity market." Since the economic purpose of capacity markets is to provide generators the "missing money" to support the capacity needed to provide the target level of electric system reliability, one might ask why is there a need for reserve shortage pricing in a region such as New York which has a capacity market.

To the extent that defects of the spot market, such as inadequate shortage pricing, give rise to the missing money problem, the burden of providing appropriate generation performance and investment incentives shifts to the capacity market. The larger the total revenues collected through the capacity market rather than the energy or ancillary service market, the greater the concern with the many inherent approximations that appear in the necessary simplifications of the complex problem of constructing forward estimates of resource requirements and defining administrative requirements to provide appropriate performance and investment incentives for capacity suppliers. By contrast, the better the pricing and price signals in the spot market, the less would be the importance of errors or missing incentives in the capacity market. Hence, better shortage pricing would help by reducing the impacts of unavoidable errors in capacity market implementation discussed in this report. Furthermore, electric system reliability depends not only on the nominal megawatts of physical generating capacity in the ground, and contracted demand response, it also depends on the characteristics and performance of those resources.

Providing all of the "missing money" through a capacity market introduces "missing incentives" with respect to capacity resource characteristics and performance. Capacity market designs such as those used by the New York ISO, PJM and ISO New England attempt to compensate for the "missing performance incentives" with administrative rules, but these efforts are at best only partially successful.[28] In addition, attempting to use capacity market rules to elicit capacity resources with the optimal mix of characteristics

28 See, for example, William W. Hogan, "On an 'Energy Only" Electricity Market Design for Resource Adequacy" September 23, 2005; Scott M. Harvey and Scott Travers, "Market Incentives for generation Investment" December 2, 2008; Scott M Harvey, "Resource Adequacy Mechanisms: Spot Energy Markets and Their Alternatives" Center for Research in Regulated Industries, 19th Annual Western Conference, Monterey California June 28, 2006; Scott Harvey, "ERCOT Market Design, Capacity Markets, and Resource Adequacy" Gulf Coast Power Association Workshop, May 4, 2012.

to meet load over the operating day has the potential to become more and more difficult as the diversity of the resource mix increases and has the potential to end badly, resulting in both lower reliability and higher consumer cost.[29] Combining a capacity market design with appropriate shortage pricing for both capacity (reserve shortage pricing) and ramping capability (shortage pricing reflecting a lack of ramp capability when aggregate capacity is adequate) can potentially provide some of the "missing incentives," while preserving most of the benefits of the capacity market system.

The "missing incentives" are both performance incentives and investment incentives.

- The missing "performance" incentives impact the efficient operation of existing assets;
- The missing "investment" incentives impact the kind and characteristics of the assets that are available to maintain reliability.

The missing performance incentives impact:

- Demand response performance and cost;
- Resource availability (economic outages, forced outages);
- Bidding and load forecasting by load serving entities;
- Resource maintenance scheduling (planned outages);
- The scheduling and delivery of interchange.

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29 ISO New England, however, may take this approach. See ISO New England, "Using the Forward Capacity Market to Meet Strategic Challenges," May 2012, Bob Ethier, ISO New England, "FCM Tranches" March 19, 2012.

Demand Response Performance and Cost

Shortage pricing provides incentives for power consumers buying (or selling back) power at real-time prices to respond to reserve shortage conditions by reducing consumption without the infrastructure and administrative costs associated with negawatt programs such as SCR and EDRP that pay for reductions in power consumption relative to pre-defined baselines. Shortage pricing in an energy-only market can thereby incent demand response that would be uneconomic to provide in a capacity market negawatt system because of the administrative costs of participating in capacity market negawatt programs. Shortage pricing in an energy-only market can also incent demand reduction by power consumers that cannot commit to reducing consumption as required for participation in capacity markets, but would be able to reduce their consumption in response to high prices in some circumstances. Some such consumers might be able to participate in a capacity market through aggregation with other consumers able to reduce consumption in some circumstances, but the administrative overhead cost of participation in ICAP market negawatt programs may exceed the benefits to many such consumers.

While the New York electric system will rely primarily on the New York ISO's capacity market to support resource adequacy, including supporting demand response through the capacity market, the performance incentives provided for reduced power consumption during reserve shortage conditions through improved real-time shortage pricing could be valuable as the New York ISO becomes more dependent on demand response in the capacity market. Improved shortage pricing would provide additional incentive for power consumers not participating in the capacity market, including consumers participating in the Emergency Demand Response Program (EDRP) program, to reduce consumption in the event SCR resources do not perform as projected during a reliability event.[30] The performance of capacity market demand response resources is unlikely to raise material reliability issues as long as the

30 The New York ISO Emergency Demand Response Program is a purely voluntary demand response program that is activated by the New York ISO based on reliability considerations.

current surplus of generating capacity persists, but will become important when the economy recovers and NYCA firm load rises to a level that is more in balance with available generating capacity.

It would be reasonable to anticipate that demand response participation in the New York ISO capacity market will in the longer run be similar to the levels seen in the PJM and ISO New England capacity markets. At those levels of demand response participation in the capacity market, and with capacity margins more in line with the target quantity, poor performance by capacity resources (such as poor performance by demand response resources or intermittent generation) will have the potential to impact New York reliability.

The uncertainties associated with capacity resource performance as the New York electricity market evolves toward greater reliance on demand response and intermittent resources can be addressed by inflating the UCAP target to provide an extra margin of capacity. Rather than further raising capacity costs for firm load, however, an alternative approach would be to provide stronger incentives for reductions in power consumption during extreme shortage conditions by power consumers not participating in the capacity market. If SCR and other capacity market resources perform as expected, high shortage prices would rarely if ever impact real-time energy market prices, because given the reliability targets used to get capacity requirements there would be few hours of substantial reserve shortages in even a high load year. However, higher shortage prices that would apply in the event of material reserve shortages that might develop if capacity resources do not perform as projected would provide stronger incentives for voluntary real-time reductions in power consumption by power consumers not participating in the capacity market but either participating in the EDRP program (which pays the higher of $500 or the LBMP price to consumers reducing consumption relative to a baseline when directed by the New York ISO), or by power consumers paying real-time prices for their energy consumption.

Resource Availability (economic outages, forced outages)

In energy-only markets, generating resources must be available during high price shortage hours in order to recover their fixed costs and any return of or on investment, and the high prices during shortage conditions provide generation resources with a strong incentive to be available and stay available during such hours. Because spot energy and reserve prices are capped at much lower levels under capacity market systems, generating resources as discussed above only recover a portion of their fixed costs and return of and on investment through energy market revenues, so have less incentive to be available during shortage conditions than units operating in energy-only markets. Hence capacity markets must put in place rules to try to ensure that capacity that receives a capacity payment is available when it is needed to maintain reliability. The New York ISO's current UCAP methodology distinguishes between resources with high and low forced outage rates but does not provide efficient incentives for generation to be available specifically during stressed system conditions. As discussed below in Section IIIF, the weakened availability incentives of a capacity market system have also been an issue, and perhaps more of an issue, for PJM and ISO New England.

Bidding and Load Forecasting by Load Serving Entities

Understated real-time prices during shortage conditions, including those arising from load forecast error, reduce the incentive of load serving entities to bid a margin above their expected load in the day-ahead market to cover load forecast uncertainty. This is because the consequences of under forecasting power consumption are reduced by the lower prices that would prevail if demand exceeds the expected value, leading to reserve shortages or even load shedding. This missing incentive of load serving entities can create a need for an ISO to account for load forecast uncertainty in the day-ahead market by committing additional capacity and socializing any resulting uplift costs and potentially incenting virtual supply bidding strategies that magnify those uplift costs. This missing incentive does not appear to have been an issue in the New York electric market in recent years, perhaps because of the incentives provided by the New York ISO's current shortage pricing design. It is desirable to maintain these incentives as the New York electric system becomes more dependent on intermittent resources and the level of net load (load minus intermittent output) becomes more variable and uncertain.

Resource Maintenance Scheduling (planned outages)

Low shortage prices also reduce the foregone revenues from extended maintenance outages that overlap a shortage event. There is therefore less incentive for a capacity supplier to bring its generating resource back early from a maintenance outage in response to changed market conditions that increase the likelihood of shortages than would be the case in an energy-only market with appropriate shortage prices. Although capacity market systems, including that of the New York ISO, require maintenance outages to be coordinated with the New York ISO, once a resource is out on an approved maintenance outage, it has less incentive to accelerate its return to service in response to tight supply than would a resource in an energy-only market. The lower energy and ancillary service prices are during shortage hours, the less incentive generating resources have to return to service early.

Scheduling and Delivery of Interchange

The consequences of failing to deliver interchange in real time are less if real-time prices do not reflect the severity of shortage conditions. At the margin this encourages the scheduling in the day-ahead market of power that might not be available in real time. When imports scheduled in the day-ahead market are not available to be scheduled in RTC, it may be too late to commit the units needed to maintain reliability if replacement imports are not available from other control areas because of regional shortage conditions.

Missing investment incentives impact:

- Investment in intermittent resources;
- Investment in energy-limited vs. conventional resources;
- Load serving entity forecasting and contracting incentives;
- Deliverability rules and the operation of existing capacity deemed deliverable versus investment in new generation with lower costs.
- Investment in thermal resources with higher ramp rates and shorter start times, and that are economic in the energy market and on-line or able to start quickly when needed.

Investment in Intermittent and Energy-Limited Resources

The stylized portrayal of the missing money problems in Figures 2 and 1 presumed that the generator resources were available during all of the missing money hours. Energy-limited and intermittent resources would generally not be available during all the hours with the missing money and might not be available during most of them. Paying the full amount of the "missing money" in the form of a capacity payment to resources that would not be available during all of the hours in which they are needed to maintain reliability provides too much incentive for investment in those types of resources, while rules that do not pay them the full value of power in the hours they were available provide too little incentive for those resources to come into service. Providing the correct balance in incentives for intermittent and energy-limited resources is very difficult within the constraints of a capacity market resource adequacy design that must rely on administrative rules to define requirements. It is particularly difficult to accurately account for the resource adequacy value of intermittent and energy-limited resources because of the wide variety of resource types with widely varying performance characteristics.

Deliverability Requirements

Capacity market deliverability tests are a central issue in implementing capacity market systems. Because generators receive capacity payments whether they operate or not, there is no locational price signal in a capacity market absent some form of deliverability test, locational capacity market, or some other form of administrative requirements. PJM, ISO New England and the New York ISO have all struggled over the years with how to apply some form of deliverability test to resource suppliers in the capacity market. The New York ISO originally addressed these issues with a zonal capacity market, later supplemented by a deliverability test required by FERC. The deliverability test has performed rather poorly as discussed by the Independent Market Monitor in its annual reports[31] and in Section IIE below.

The New York ISO will be able to correct many of the problems with the current deliverability test by creating one or more additional capacity market zones east of Central East as discussed in Section IIE below. There is, however, a potential for inadequate shortage pricing and insufficient importance of energy and ancillary service revenues within the overall resource adequacy design to result in a need for narrower and narrower capacity market zones to incent the construction, or continued operation, of resources in locations needed to meet various reliability criteria.

A capacity market is better suited to meeting the narrow objective of replacing the “missing money” arising because reserve shortage prices are set below the levels that would support resource adequacy in an energy-only market, than if it is used to try to insure capacity resources have the characteristics, including location, needed to meet narrow reliability requirements. The potential for a capacity market to devolve into a system with narrower and narrower zonal capacity requirements to address increasingly

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31 See, for example, David B, Patton, Pallas Lee VanSchaick, and Jie Chen. *2011 State of the Market Report for the New York ISO Markets*. April 2012, p. 162-165.

narrow transmission security requirements can potentially be avoided by insuring that these requirements are accounted for in energy and ancillary service market prices.

Resource Capabilities such as Ramp Rates

With the integration of increasing amounts of intermittent resources in the U.S. electric system, it is becoming increasingly important for the electric system operator to have sufficient ramping capability, not just capacity, available to respond to the variations in the output of these intermittent resources. The NYISO is not expected to have to manage as high a level of intermittent resources as operators such as the Midwest ISO, ERCOT, the California ISO or BPA and may be able to manage the impact of intermittent resources over the foreseeable future with its existing resource mix and the recent implementation of 15 minute scheduling with Hydro-Quebec and PJM and future implementation with ISO New England. Regardless, in our view ramping capability is another type of resource characteristic that is better addressed by providing appropriate incentives in the energy and ancillary service markets than through capacity market requirements.

Important elements of the current energy and ancillary service market design that incent generating resources to provide ramping capability are five minute pricing of generator output and shortage pricing for the use of regulation capacity to provide ramp capability in the energy market. If changes in the New York supply mix create further demands for ramp capability, we recommend that the necessary incentives be provided in the energy and ancillary service markets, either through refinements to regulation shortage pricing or introduction of new ramp capability type energy market products such as those being considered by the Midwest ISO.[32]

32 See Midwest ISO, "Ramp Capability in MISO Markets", Stakeholder 5th Technical Workshop, April 14, 2012.

The economic goal of a capacity market design should be to maintain reliability by replacing the "missing money," not to be the sole means by which generating and other capacity resources recover their fixed operating costs and return of and on investment.

3. Increasing Reliance on Energy Market Revenues

a. Overview

Within the structure of the current scarcity pricing employed by the New York ISO, the number of reserve shortage hours will likely remain fairly low, so modest changes in shortage costs would not be sufficient to replace the need for capacity payments and capacity markets, and we do not recommend that the New York ISO attempt to eliminate the capacity market. As pointed out by Mark Reeder of the New York Public Service Commission in his 2006 article,[33] a difficulty in increasing the emphasis on energy market revenues within the NYISO capacity market design is that the capacity market is intended to procure sufficient capacity that the number of reserve shortage hours will be relatively low, on the order of 8-15 hours during an average year with the target level of capacity. There is of course variation from year to year in weather conditions, outages, and the availability of imports on high load days that can result in a higher or lower number of hours of reserve shortage during a particular year, but over time the number of reserve shortage hours will average out to a fairly low number of hours per year.

In addition, the availability of capacity in excess of the target level will reduce the number of reserve shortage hours while shortages in capacity relative to the target level will increase the number of reserve shortage hours. In recent years the NYISO has had substantially more than the target level of capacity, which has served to reduce both the likelihood of a loss of load event and the frequency of reserve shortages. This capacity surplus is probably a result of capacity built to meet load levels that were

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33 Mark Reeder, "Want to Put an End to Capacity Markets? Think Real-Time Pricing". *The Electricity Journal*. July 2006, pp. 38-48.

expected to be much higher when the construction of the units began. Table 44 (appended) reports the load levels that were projected for 2010 and 2011 during 2006 and 2007, when units coming on line in recent years would have been committing to come on line, compared to actual capacity market requirements and peak loads. Table 44 (appended) shows that the 4 year in advance load forecasts for 2010, 2011 and 2012 have substantially exceeded the one year in advance load forecast used to set the New York ISO capacity requirement. While Table 44 portrays New York ISO load forecasts, rather than those of market participants, the demand projections of market participants committing to building or contracting for generating capacity in these years likely also exceeded actual load levels in recent years.

If there will be few hours of shortage per year in a resource adequacy design based on capacity requirements, modest increases in shortage prices would not substantially increase the energy market revenues of capacity resources and hence not achieve much reduction in the proportion of their net revenues received through the capacity payment. This was recognized by Mark Reeder, who proposed relying on the ability of power consumers to reduce power consumption in setting the capacity requirement so as to increase the number of shortage hours and transition to a resource adequacy design based solely on energy and ancillary service market revenues. The premise for this approach was an expectation that a substantial amount of demand would drop off the New York ISO system at prices above $400 per megawatt hour, but that has not happened in practice.

The frequency of reserve shortage conditions has been even lower in the past few years than normally expected. This is probably a result of the surplus of capacity produced by the recession. In recent years the NYISO, ISO-NE and PJM have all had large capacity surpluses relative to the actual level of demand. However, the fact that there are few hours of reserve shortage and very low shortage revenues when there is a high level of excess capacity is not a bad outcome; it is an appropriate outcome.

It would take large changes in the New York ISO shortage pricing design to achieve a major shift in the balance between the energy/ancillary service market and the capacity market as sources of net margin for capacity resources, and we do not recommend that the New York ISO attempt to eliminate the capacity market. There are, however, four areas in which changes in the shortage pricing design would both correct limitations of the current pricing system and somewhat increase the importance of energy and ancillary service market net margins. These areas are the relationship between the shortage pricing levels for reserves, particularly NYCA 30-minute reserves, and demand response activation decisions, the lack of any reserve product corresponding to the reserves, e.g. undispatched capacity, needed to maintain transmission security when Leeds-Pleasant Valley or similar constraints are binding, and potentially other In-City reliability limits. These subjects are discussed below.

b. Shortage Pricing and Demand Response Activation

The design of the New York ISO's shortage pricing not only impacts the level of energy and ancillary service revenues relative to capacity market revenues, it also impacts the level of demand response. Two aspects of the current design are important in this respect: the inconsistency between the current shortage prices for 30-minute reserves and operator actions, and the structure and level of shortage pricing for 10-minute reserves.

30-Minute Reserve Pricing and Demand Response

Over the past few years, the New York ISO and its stakeholders have been discussing the relationship between demand response activation and real-time energy market prices. When demand response is activated in response to an actual or projected shortage of 30-minute reserves, the demand response activation tends to greatly reduce energy prices, while typically paying $500 per megawatt for the reduction in load provided by the demand response resources.[34] One of the suggestions for dealing with this asymmetry between energy market prices and the cost of demand response activation would be to set energy market prices based on the cost of demand response activation.[35]

Underlying the pricing problem with demand response is an inconsistency between the current shortage pricing for 30-minute reserves, which range from $50 to a maximum of $200 per megawatt as shown in the left column of Table 9 below, and operator activation decisions for demand response. If it is worthwhile to activate demand response at an incremental cost of $500 to restore 30-minute reserves, then this should be reflected in the shortage pricing of 30-minutes reserves. If shortage pricing for 30-minute reserves were set appropriately, the activation of demand response in order to reduce a shortage of 30-minute reserves would appear economic based on energy market prices and internal generation backed down as a result of demand response activation would appear economic based on energy and reserve prices. Conversely, if a shortage of 30-minute reserves is not really worth $500 per megawatt, then the New York ISO operators should not be activating demand response at a cost of $500 per megawatt hour in order to avoid such a shortage of 30-minute reserves.

Table 9
NYCA 30-minute Reserve Shortage Prices

Total Reserves	Current	Alternative
≥1800	0	0
1750-1799	$50	$50
1700-1749	$50	$150
1650-1699	$50	$250
1600-1649	$50	$350
1400-1599	$100	$500
1200-1399	$200	$600

34 EDRP demand response resources are paid a minimum of $500 per megawatt hour for their reduction in load relative to their baselines; see New York Independent System Operator, Market Services Tariff Attachment G, Section 22

35 See, for example, Mark Younger, Revised Pricing for SCR Events. NYISO Market Issues Working Group, August 29, 2011.

The cost of restoring 30-minute reserves through activation of demand response is the difference between the $500 per megawatt hour typically paid for the demand response and the bid price of the generation that is backed down. If the bid price of the backed down generation were $100 per megawatt hour, the net cost of the reserves would be $400 per megawatt hour.

The current inconsistency between the shortage price for 30-minute reserves and the payments for real-time demand response, SCR and EDRP also means that these shortage prices would not provide the Real-Time Commitment software (RTC) used by the New York ISO the appropriate incentive to schedule imports in order to maintain 30-minute reserves, as incremental 30-minute reserves are valued at a maximum of $200 per megawatt hour in RTC. Hence, if incremental generation backed down by imports had a bid price of $100 per megawatt hour, it would not be economic for RTC to schedule imports costing more than $300 per megawatt hour to maintain 30-minute reserves. Moreover, it would not be economic for RTC to maintain imports costing more than $300 per megawatt hour to preserve 30-minute reserves and it would be economic to schedule exports that depleted 30-minute reserves for less than the cost of the demand response that made the capacity available to support exports. For small shortages of 30-minute reserves, it would be economic to schedule exports at prices perhaps as low as $150 per megawatt hour at the same time that the New York ISO was activating demand response at a cost of $500 a megawatt hour to restore those reserves.

These pricing inconsistencies between demand response, imports and 30-minute reserves may not have been a significant issue in the past, given the long lags in scheduling imports and exports.[36] With imports and exports only scheduled once an hour for a change 75 minutes in the future, there has been a long lag between the time at which demand response activation begins to impact power demand and the time when this reduction will be recognized in RTC and impact the pricing and scheduling of net imports. This time

36 We have not, however, actually examined the extent to which the New York ISO has historically failed to schedule imports or reduce exports that would have maintained 30-minute reserves in place of activating demand response as a result of the low shortage price for 30-minute reserves.

lag will be dramatically reduced with the introduction of 15 minute scheduling, however, so there will be an increased potential in the future for the inconsistent pricing of demand response and 30-minute reserves to lead to inefficient outcomes. We do not take a position on whether the inconsistency should necessarily be addressed by increasing the shortage price of 30-minute reserves or by changing operating practice to not activate demand response in response to a 30-minute reserve shortage. But whatever the choice, pricing should be consistent with operator and RTC decisions. If consistency were introduced by raising the shortage price of 30-minute reserves, this would tend to increase energy market shortage revenues, both east and west of Central East.

If a more nuanced demand curve for 30-minute reserves were introduced that rose from the current $50 per megawatt hour level for minimal shortages to $600 per megawatt hour for large shortages, the activation of demand response would be economic based on the shortage pricing. Even with consistency between reserve shortage pricing and demand response activation decisions, the activation of demand response might typically over relieve the shortage of 30-minute reserves and require a bid production cost guarantee for the demand response resources over their minimum run time,[37] but the shortage pricing would send a consistent price signal for generation and for demand response (particularly EDRP which receives a payment based on the LBMP price). If there were no longer a shortage of 30-minute reserves at the end of the demand response minimum run time, prices would be low and demand response would have no incentive to continue reducing power consumption. On the other hand, if real-time prices reflect a continuing reserves shortage, this would send a signal for continued reductions in power consumption.

Such revised shortage pricing for 30-minute reserves that addressed the inconsistency between demand response costs and 30-minute reserve shortage prices would likely have only a small impact on generator shortage revenues or consumer energy costs. Over the June 1, 2006 through May 31, 2008 period that

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37 I.e. they would be paid $500 per megawatt hour for the reduction in power consumption even though the real-time spot price of power was much less than $500 per megawatt hour.

we previously studied, there were just under 11 hours of NYCA-wide 30-minute reserve shortages. These shortages would have produced around $1090 per megawatt year of shortage revenues based on current shortage prices and would have produced around $4000 per megawatt year of shortage revenues with the illustrative alternative shortage prices portrayed in Table 9.[38] While these changes in shortage pricing for 30-minute reserves would not materially change the balance between energy market and capacity market revenues, they would have a marginal impact while producing real-time energy market prices that would be more consistent with operator decisions and demand response costs. Correctly aligning energy prices and operator decisions involving demand response will potentially become much more important with the coming introduction of demand response in the real-time New York ISO energy market.[39]

10-Minute Reserve Pricing and Demand Response

The introduction of more nuanced 30-minute reserve pricing as discussed above would likely provide somewhat more incentive for market participants to develop EDRP demand response that could be deployed by the New York ISO during reserves shortage conditions but there would likely be additional demand response that would be available for deployment only at higher price levels. Thus, at present a shortage of total 30-minute reserves and total 10-minute reserves results in a $650 per megawatt hour margin over the incremental energy offer price west of Central East. If the maximum shortage pricing for 30-minute reserves were raised to $600 per megawatt hour so that more moderate shortages would produce energy prices supporting demand response activation, then such a shortage of 30-minute and 10-minute reserves would produce a Western Reserve price of $1050. However, one limitation of the current design is that at present the Western price would remain $650 per megawatt hour until reserves declined to the point that the New York ISO was short of spinning reserves as well. Raising the maximum

38 The penalty values in the right hand column do not reflect a specific proposal and are simply illustrative of values that would be more consistent with EDRP and SCR costs.

39 Donna Pratt, New York ISO, “Market Design Concepts for Demand Response in the Real-Time Energy Market”, Joint Price-Responsive Load and Market Issues Working Groups, Oct. 4, 2012.

shortage price for 30-minute reserves to $600 per megawatt hour would cause the Western price to raise to $1050 per megawatt hour if the New York ISO were short of 10-minute total and total 30-minute reserves, providing additional incentives for demand reduction, but this price would be the same for all levels of 10-minute reserve shortage. As with 30-minute reserves, a more nuanced pricing of 10-minute total reserves that provided for higher shortage prices in the event of more extreme capacity shortages would provide a stronger incentive for demand response in these circumstances.

As observed above, such extreme levels of reserve shortage should be extremely rare under the current New York ISO capacity market design if capacity market resources performance is in line with expectations and requirements. However, there is a potential as the New York ISO resource mix evolves over the next decade for the assumptions regarding resource performance used to develop capacity market requirements to understate actual capacity requirements for future resource portfolios, resulting in larger than projected capacity shortfalls until the assumptions are better aligned with actual resource performance. In these circumstances, higher shortage prices for more extreme shortages of 10 minute reserves might be helpful in eliciting demand reductions that would help maintain reliability.

One view would be that the capacity market SCR program provides much stronger incentives for demand reduction than do high prices in the energy market. This is the case in Zone J (New York City), even at current relatively low capacity prices. At past summer capacity prices in the range of $13,000 per megawatt month in Zone J, if 20 hours of activation per year were expected (a generous estimate) the capacity market payment per megawatt hour of demand reduction would be around $3,900 (6 months * $13,000 per megawatt month/ 20 hours), yielding total value in excess of $4000 per megawatt hour for demand reductions when the avoided energy payments are accounted for. Even at the lower capacity prices prevailing in Zone J during the summer of 2011, averaging a bit more than $8,000 per megawatt month, the savings per hour would exceed $2,500 for 20 hours of demand response activation, plus the additional per megawatt hour payments for real-time load reduction during event hours that would be at least $500 per megawatt hour. A countervailing factor is that while the capacity surplus has depressed prices in the capacity market, it should also be expected to reduce the likelihood of being called, hence reducing the expected cost of participating in the demand response program and raising the expected payment per megawatt hour of actual load reduction, so that expected savings might have been somewhat higher than the $2500 per hour figure suggests.

The incentives provided by the capacity market for demand response are radically different outside of Zone J, however. Long Island capacity market prices averaged only a little over $2000 a month in the summer of 2010, providing an incentive of only around $635 per megawatt hour of demand reduction if 20 hours of interruption were expected. 2011 capacity market prices averaged less than $300 a megawatt month, providing an incentive of less than $100 per megawatt hour of expected demand reduction over the summer months based on the same assumed 20 hours of interruption, or $200 per megawatt hour if 10 hours of interruption were expected.

Capability prices have averaged slightly more than $3000 per month so far during the summer of 2012, implying a $900 payment for demand reduction if 20 hours of interruption were expected. Prices in the West, including Zones F, G, H, and I which are east of Central East, have been at the same depressed level as Long Island in the summer of 2011 in both 2010 and 2011, and somewhat lower than Long Island prices during the summer of 2012. In practice, the capacity market currently provides only token incentives for demand response outside Zone J.

These low capacity prices in Long Island and upstate New York reflect the current surplus of capacity (including imports) in these regions and hence the low need for demand response given the large surplus of generating capacity. At the average capacity prices during the pre-financial-crisis summers of 2006 and 2007, the demand response incentive exceeded $2100 an hour on Long Island and was nearly $1000 an hour in rest of state. The introduction of a G, H, and I zone might lead to somewhat higher capacity prices in these east of Central East zones in the future, providing more incentive for demand response.

An important feature of capacity market demand response programs is that realizing these payments for demand reduction by participating in the capacity market through the SCR program requires an advance commitment by a demand response resource to reduce load when needed. Some power consumers that would at times be able to reduce consumption when the New York transmission system is under stress may not be able to guarantee such reductions in consumption at all times. While such consumers can still participate in the capacity market by individually enrolling in a demand response portfolio and contributing to the aggregate performance of the portfolio, participation as part of such a portfolio also diminishes the consumer's marginal incentives. Moreover, capacity market incentives apply only to the guaranteed reduction, the capacity payments do not apply on the margin to additional reductions that may be feasible on a particular day in a particular hour, which would be compensated based on the real-time energy price (with a minimum payment of $500 per megawatt hour). Resources participating in the EDRP program do not have to make a commitment to reduce load but receive only the higher of the real-time energy market price or $500 for reductions in consumption, so higher prices could induce more real-time response from such resources.

A recent Brattle Group evaluation of ERCOT resource adequacy noted the large load forecasting errors, around 1700 megawatts, that ERCOT has experienced when real-time energy prices reached shortage levels of $3000 per megawatt hour in the summer of 2011. Part of the load forecast error associated with high prices is likely due to the ERCOT transmission cost allocation design, which encourages conservation during the peak load hours, but a portion was likely also due to the high energy prices.[40] There is a similar situation in Alberta in which some consumers predictably reduce consumption in response to high real-time power prices to which they are exposed through the retail rate.[41]

The full impact of improved shortage pricing on real-time demand response during stressed system conditions will not be manifested for a number of years as it will be impacted by the penetration of real-time metering, real-time pricing under utility default pricing programs, evolution in retail access pricing contracts to expose consumers to real-time prices for high levels of consumption and consumer awareness of the potential for high prices.

Regulation Shortage Pricing

The shortage pricing of regulation provides an important signal for the development and maintenance of ramp capability in the New York ISO design. We do not discuss this subject in detail in this report because the New York ISO recently reviewed and adjusted its shortage values for regulation as summarized in Table 10. These shortage values are a key parameter impacting the returns to flexible and fast ramping capacity and provide an added return to resources with fast ramping capability for generation resources to participate in the economic dispatch.

40 Brattle Group, "ERCOT Investment Incentives and Resource Adequacy". June 1, 2012, p. 89-90. The reduction in load was not a result of reduced consumption by power consumers enrolled in a demand response program; it was just power consumers responding to high prices during shortage conditions. ERCOT also has 4 CP pricing of transmission cost, which allocates transmission costs based on peak hour consumption and also tends to provide an incentive to reduce consumption during peak hours. There are differences between ERCOT and New York in terms of retail metering and the design of the retail access programs as well as in the amount and type of industrial load and the amount of load providing reserves for the ERCOT system. Our point is simply that consumers with real-time meters and paying real-time prices will reduce consumption in response to high prices even without negawatt type demand response programs in the capacity market.

41 References to this completely voluntary demand response can be found in a number of Alberta Electric System Operator documents, such as: Alberta Electric System Operator, Demand Response Working Group, July 23 meeting. 2008 and Matthew Davis, Alberta Electric System Operator, Currently Existing Demand Response. January 27, 2009; Brattle Group, Demand Response Review. March 2011, p. 19.

Table 10
Regulation Shortage Prices

	2005 – 2011	2011 - Present
0 – 25 MW	$250	$80
26 – 80	$300	$180
> - 80	$300	$400

With the implementation of 15 minute scheduling with Hydro-Quebec in 2011, the implementation of 15 minute scheduling with PJM in 2012 and the pending implementation of 15 minute Coordinated Transaction Scheduling (CTS) scheduling with ISO New England, the New York ISO has materially more capability to balance supply and demand in response to unanticipated changes in net load than in prior years.

Should future changes in the New York ISO resource mix begin to produce a lack of dispatch flexibility and ramp capability that causes reliability concerns, review of these shortage values would be appropriate. In our view, changes in energy market pricing that increase the returns to flexible generation would be the preferred method of incenting greater flexibility in the New York resource mix, rather than attempting to micro manage the flexibility of the New York resource mix in the capacity market.

c. South of Leeds-Pleasant Valley Transmission Security

Another inconsistency of this sort is the activation of demand response to reduce load south of Leeds-Pleasant Valley and related constraints to maintain unloaded capacity able to be dispatched up to reduce flows in the event of a contingency, while no reserve requirement corresponding to this reliability need is modeled or priced in the market. The failure to price this reliability requirement may have contributed to the need to create a new capacity market zone, although it is likely that constraint would have been binding in deliverability tests even had higher reserve revenues kept additional generation south of

Leeds-Pleasant Valley in operation. Even if the failure to price this reserve requirement would not have avoided the need to create the new zone or zones, had modeling the requirement kept additional Zone G generation in operation, this would have reduced the Zone J locational capacity requirement, avoiding the need for new, likely higher cost, Zone J capacity.

d. Conclusion

We do not recommend that the New York ISO attempt to use shortage pricing to replace the capacity market. We do, however, recommend that the New York ISO modify its shortage pricing provisions to eliminate or at least reduce the inconsistencies that currently exist between shortage prices and New York ISO operating decisions, which will tend to somewhat increase the importance of energy and ancillary service revenues relative to capacity market revenues and improve performance incentives during system conditions that require these operator actions.

Moreover, the potential need for a new capacity market zone within New York City defined by the 138/345 kv system, as discussed by the Independent Market Monitor in his 2012 report,[42] raises the concern that not all New York City reliability requirements are not reflected in energy and ancillary service prices under the current design. If such reliability requirements are not reflected in energy and ancillary service markets, they will contribute to future needs to establish additional, smaller capacity market zones to meet these reliability requirements. We recommend that these and similar reliability requirements be reflected in energy and ancillary service market constraints and prices to the extent feasible, rather than defaulting to resolution through creation of new capacity market zones.

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42 See David B, Patton, Pallas Lee Van Schaick, and Jie Chen, *2011 State of the Market Report for the New York ISO Markets*, April 2012 p. 38.

4. Assessment of Current Energy Adjustment Methodology

The final topic in this section is a review of the current NYISO methodology for estimating the energy and ancillary service revenues adjustment to the gross CONE. The original adjustment for these revenues was based on a production cost simulation carried out by Levitan, which developed the revenue estimates used for the 2005/2006 through 2007/2008 capacity market years.[43] NERA has developed the last couple of revenues estimates, covering the capacity market years 2008/2009 through 2010/2011 and 2011/2012 through 2013/2014 using an econometric model.[44] There is a concern that the model shows energy and ancillary service revenues dramatically impacted by very small amounts of excess capacity relative to the target.

Tables 4 and 5 above show that the estimated energy and ancillary service revenues used to set Net CONE have been materially overstated in recent years relative to the earnings of a hypothetical unit as calculated by the Independent Market Monitor. The Service Tariff states that the energy and ancillary services offset is supposed to be an estimate of the likely net revenues over the period covered by the demand curve, rather than a measure of the long-run expected level of such revenue.[45] However, the estimates used in recent years are far above levels that a hypothetical unit could have realized even in the 2006-2008 period with very high gas prices. These forecasting errors are presumably in part a result of the recession following the financial crisis, which was of course not anticipated in the model used to project expected energy and ancillary service revenues in 2007. The outcome in which energy and

43 Levitan & Associates, "Independent Study to Establish Parameters of the ICAP Demand Curves for the New York Independent System Operator". August 16, 2004.

44 NERA Economic Consulting," Independent Study to Establish Parameters of the ICAP Demand Curve for the New York System Operator". July 13, 2007 and November 15, 2010.

45 New York Independent System Operator, Market Services Tariff, Section 5.14.1.2. Since the CONE is an ad hoc levelized long run measure of the estimated capital cost over time of new capacity, there is a conceptual inconsistency in defining the energy and ancillary services revenue offset as measuring short--run revenues. However, since other tariff language requires the adjustment to be calculated based on an assumed balance in the capacity market, rather than reflecting short-run surpluses or shortfalls in capacity, the methodology is not really consistent with the description as measuring likely revenues over the period covered by the demand curve.

ancillary service revenues are lower than projected when the demand for capacity is lower than projected is an appropriate outcome.

While we can understand why NERA's energy margin estimates for 2009/2010 and 2010/2011 were higher than actual margins as these estimates were developed prior to the financial crisis and recession beginning in 2008, it is less obvious why NERA's estimates for energy and ancillary service revenues for 2011/2012 and subsequent years were even higher than the prior estimates rather than lower. These estimates are far higher than the hypothetical revenues calculated by the Independent Market Monitor based on actual market prices (see Table 5).

Projecting expected future revenues is difficult and all approaches have limitations, particularly when major drivers of energy prices, such as fuel prices and power demand, are difficult to predict more than a short-time into the future. Some of the factors that may have impacted the accuracy of these energy margin projections and that should be considered in constructing future estimates are outlined below. First, it is important in estimating these net energy and ancillary service revenues to keep in mind that it is not energy or ancillary service prices in general that we are interested in predicting but in the net revenues to the CONE unit. Hence, in calibrating estimates against actual prices, whether the estimates are based on simulations, statistical analysis, or some other methodology it is important to focus on comparing actual and projected prices during the hours in which actual or projected prices would produce net revenues for the CONE unit.

In particular, while one might choose to estimate a log linear model of prices as NERA has used in its statistical analyses, comparisons of actual and projected prices for the purpose of assessing how well the model is predicting prices should be based on actual and projected prices, not the log of these prices. Basing an assessment of the goodness of fit on the log of prices could mask large errors in projecting prices in the hours that matter most for the net energy revenues of the CONE unit, leading to mistaken conclusions regarding how well the model is predicting those prices.[46]

Second, while data for all hours can usefully be used to estimate the model, assessment of whether the model provides a reasonable projection of prices for use in predicting net energy revenues needs to be based on how well the model predicts prices in the high price hours that impact the net revenue calculation. Moreover, it needs to be kept in mind that accurately predicting prices and the frequency of high prices is not the same as being able to predict the impact of changes in the control variables on prices. Accurate predictions of prices used for calculating net revenues for the CONE unit need to account for both the component of prices that varies with the control variables and the impact of the component that cannot be predicted, the error term in a statistical model, i.e. an error term which is not necessarily (and probably not) normally distributed in the case of spot electricity prices.

It appears that NERA may have intended to preserve the variability introduced by the error term by letting the error term take the value they estimate in their base model when they recalculate day-ahead prices using their econometric model to adjust for the impact on prices of a lower reserve margin.[47] If we correctly understand what was done, while we agree with the concern that we believe motivated this adjustment, this methodology appears to be very sensitive to the assumed log normal structure of the prices and the error term. If this error term is material, this methodology has the potential to impact the estimated energy margin when prices are adjusted for differences in the reserve margin. Since we were not able to review the files needed to readily replicate the NERA margin calculations from the econometric model results, we cannot assess the actual impact of this element of the methodology on the estimated energy margins.

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46 Basing a regression on the log of prices compresses the difference between high and low prices, and compresses the effect of large errors in predicting high prices on goodness-of-fit statistics, which therefore may not provide a very good indication how well the model is predicting the unlogged prices, which are what generator margins depend on.

47 See NERA Economic Consulting, "Independent Study to Establish Parameters of the ICAP Demand Curve for the New York Independent System Operator," November 15, 2010, p. 49.

Third, the specification used for the simulation or statistical analysis needs to be tested to make sure it will produce sensible results if historical values are replaced with projected values that are outside the range of the data used to estimate the model.

In addition to these considerations that may have impacted the accuracy of the model used to project the prices used to estimate future energy net revenues, it is possible that the large discrepancy between actual energy and ancillary service revenues and those used to calculate net CONE was due in part to a provision in the New York ISO Market Services Tariff that governs how the adjustment is to be calculated. This provision states that these net revenues will be predicted assuming that the capacity in the market equals the minimum installed capacity requirement plus the capacity of the designated peaking unit.[48] Not only was there a capacity surplus during the period used to estimate the current demand curve, but there has been an even larger capacity surplus in the current period. Projections of what net energy revenues would have been had there not been a capacity surplus will inevitably overstate actual net energy revenues during a period in which there is a capacity surplus.

It is appropriate that the estimated net energy and ancillary service revenues used to anchor the top of the capacity market demand curve attempt to measure energy and ancillary service revenues when the system has the target level of capacity as required by Section 5.14.1.2 as this would permit recovery of the full estimated cost of entry, between energy and ancillary service revenues and capacity market payments, when capacity equals the target level.

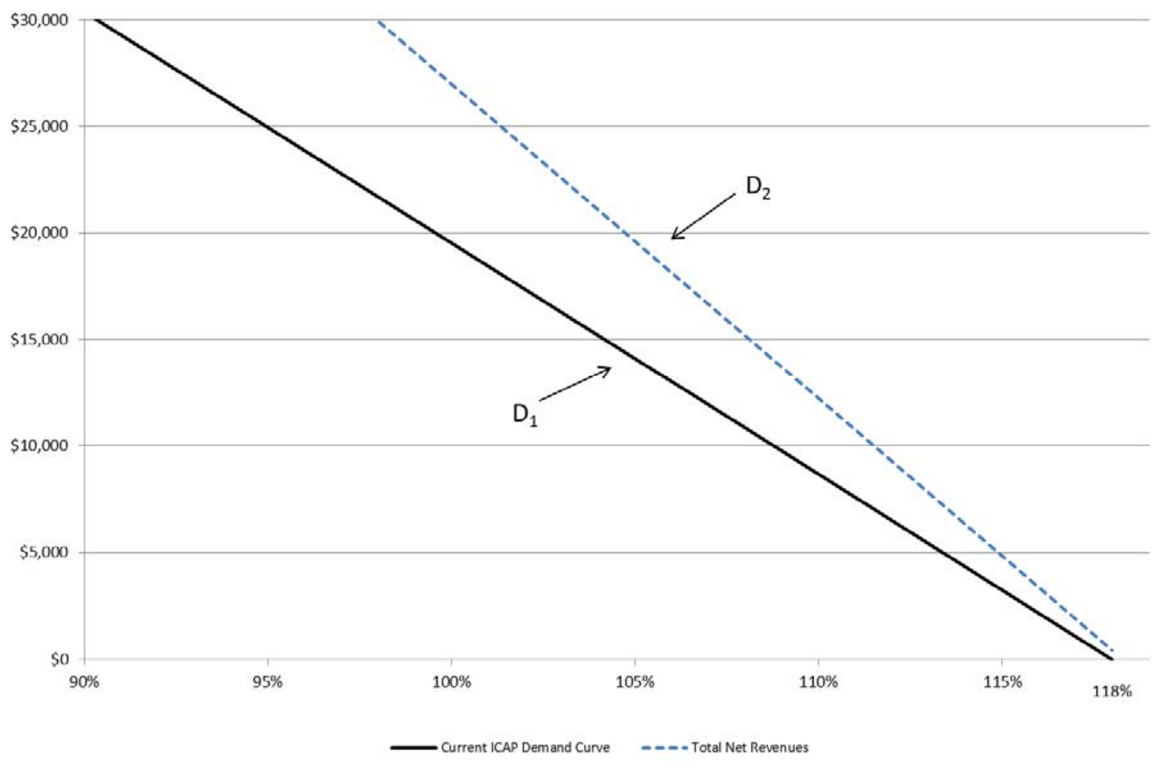
Projecting net energy revenues assuming the target level of capacity will overstate net energy revenues and understate total revenues (net energy and ancillary service revenues and capacity market revenues) when there is a capacity surplus. However, the capacity price should be less than the reference price

48 New York Independent System Operator, Market Services Tariff, Section 5.14.1.2.

when there is a surplus, so the capacity price would be below CONE in any case. However, calculating net revenues in this way will tend to somewhat further depress capacity market revenues when there is a surplus, i.e. total revenues will fall more steeply than indicated by the capacity market demand curve because net energy market revenues are also declining with increases in available capacity.

This is illustrated in Figure 45, which portrays both the capacity market demand curve (D1), relating the capacity payment to the degree of capacity surplus or shortage, and the total net revenues curve (D2), relating the sum of the capacity market payment and net energy and ancillary service revenues to the degree of capacity surplus or shortage. Because net energy and ancillary service revenues will decline with increases in capacity, line D2 is steeper than line D1.

Figure 45: New York City
(Price is $ per Megawatt-Month)



We do not recommend any changes in this methodology for anchoring the top of the demand curve because the slope of D2 is not necessarily inappropriate, it just needs to be kept in mind in evaluating the capacity market demand curve that the actual supply of capacity depends on the total net revenue line D2, which is steeper than the capacity market demand curve D1.

There is a related but distinct element of this projection that is more problematic. This is the potential for the estimated net energy and ancillary service revenues at the target level of capacity to materially understate or overstate actual net energy and ancillary service revenues at the target level because the estimates are derived by projecting outcomes outside the range of data over which the model of energy and ancillary service revenues was estimated, particularly if the model is non-linear.[49]

Estimating net energy and ancillary service revenues using the three prior years of data, as has recently been the case,[50] can contribute to the potential for overstated or understated estimates of likely net energy and ancillary service revenues at the target level of capacity because it can require projecting energy and ancillary service revenue outcomes for a capacity and demand balance that is outside the range of the data used to develop the revenues estimates.

The impact of net energy revenue projections that are inaccurate when projected out of range of the data would be limited if the capacity market remained in surplus over the period to which the demand curve applied, so that the inaccurate projections did not impact actual capacity market payments, but even then, an inaccurate anchor for the capacity market demand curve could impact development of future projects. Such an error in accurately estimating the anchor for the capacity market demand curve would be more troubling if net energy margins estimated over a period of capacity surplus were used to anchor the demand curve and determine capacity market prices over a period with a tighter capacity supply,

49 On the other hand, the estimated coefficient for the reserve margin variable reported by NERA, -.9983449 is sufficiently close to 1 that if this is the value used to project prices, there should not have been much non-linearity in the projected impact of different reserve margins, see NERA Economic Consulting, “Independent Study to Establish Parameters of the ICAP Demand Curve for New York Independent System Operator”, November 15, 2010, Appendix. However, this adjustment of the reserve margin may have interacted with the way NERA chose to incorporate the error term into the projection of prices in projecting net energy revenues.

50 See NERA Economic Consulting, “Independent Study to Establish Parameters of the ICAP Demand Curve for the New York Independent System Operator,” November 15,2010, p. 40

potentially causing net CONE to be set too low at a time when entry of new capacity is needed. It would be important in such a situation that the slope of the demand curve for capacity deficits, i.e. the slope to the left of the target capacity requirement, not be understated or it could magnify a potential capacity shortfall.[51]

While we understand the desire to base the estimation of energy and ancillary service revenues on reasonably current market conditions, we recommend that the model also be tested over a longer time frame that includes periods in which capacity supply is close, or at least closer, to the target level, to enable assessment of whether the model accurately projects net energy and ancillary service revenues in this range.

Another factor that drives generation entry is that the energy revenues used to calculate the hypothetical CONE is based on generic zonal energy prices but new units are being actually built in locations where the prices are more favorable. Hence generation built in Zone J has often been built in load pockets in which energy prices are higher than in Zone J as a whole, which of course makes economic sense. This is another reason that the net CONE calculation cannot be expected to be a completely accurate measure of the costs and revenues of real-world entrants.

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51 The focus of this report is not on reviewing past demand curve estimates, but a number of New York ISO stakeholders participating in the July 31, 2012 New York ISO ICAP working group meeting at which preliminary results were presented, requested that we assess the relative importance of the factors desired above in leading to inaccurate estimates of net energy revenues, if this could be accomplished without a major diversion of effort from the other elements of the study. We were not able to locate the data used to calculate the final energy and ancillary service adjustments so could not make such an assessment within the time frame for this report. We did review the statistical model that was posted along with the underlying data and reran the results to assess the accuracy of the unlogged predicted versus actual prices. While the R2 measuring the accuracy of the statistical model in predicting prices was around .88 when applied to the logged predicted and actual prices, it would have been less than .4 if calculated for the unlogged prices and predicted prices, consistent with our concern that the R2 of the logged model might be overstating how well the model predicts prices. Because we could not locate the data needed to replicate the step in which the energy margin was calculated, and our calculations based on the initial model did not replicate the final margin, we were not able to assess what impact the inaccuracy in predicting prices might have had on the estimated margin nor assess the impact of the tariff requirement that the margin be calculated assuming capacity equal to the target level.

5. Conclusions

We recommend that the New York ISO increase the importance of energy and ancillary service revenues in the overall resource adequacy design. This will improve some of the performance and investment incentives that can become inefficiently weak if the recovery of a return of and on investment depends too little on energy market outcomes. An initial focus would be to modify reserve shortage pricing for reserves, particularly NYCA 30-minute reserves, to be consistent with demand response activation decisions and make sure that transmission security requirements for unloaded capacity are also accounted for in the ancillary service pricing design in a manner consistent with the actions taken to maintain that unloaded capacity, such as demand response activation decisions. Beyond these changes, the New York ISO should focus on reflecting reliability requirements in the energy and ancillary service markets so that the capacity market, with potentially narrower and narrower zones, does not have to be relied upon to meet these requirements, a purpose for which it is not well suited.

C. Assessment of Tests for Application of Mitigation

1. Introduction

This report does not undertake an overall evaluation of the New York ISO's market power mitigation policies in the capacity market. Instead, it is focused on reviewing certain elements of the design relating to buyer-side market power mitigation.

The New York ISO's capacity market, like PJM's Reliability Pricing Model (RPM) and ISO New England's Forward Capacity Market (FCM), is potentially vulnerable to the exercise of buyer-side market power. Although the potential for the exercise of seller market power has long been recognized, it was later that the symmetric problem of buyer manipulation became a focus of concern. The New York ISO's spot capacity auction uses a set of offers from capacity suppliers and a demand curve for capacity to conduct a first-price non-discriminatory auction. In this type of auction the market-clearing price for each capacity region is paid to all the capacity that is offered in the spot auction at less than or equal to the market-clearing price. Buyer-side market power can be exercised because capacity buyers can in effect "withhold" their demand for capacity in this design by contracting bilaterally for high cost capacity that they then offer into the spot capacity auction at a price that is less than its full cost, or even offer as price-taking supply. If the incremental supply contracted for outside the centralized capacity market auction and offered at prices less than its full cost is sufficient to lower the market-clearing price in the auction, then the buyer will benefit through reduced payments for other capacity the buyer is required to purchase.[52] If the buyer's obligation to purchase capacity is large enough, the benefit of the reduced price paid for capacity purchased in the spot auction will outweigh the higher cost of the incremental capacity contracted for outside the auction. Hence, this form of demand withholding could be a profitable method of exercising buyer market power to manipulate the New York ISO's capacity market spot auction.[53]

An important difference between the New York ISO capacity market structure and the forward capacity markets currently utilized by PJM and ISO New England is that the New York ISO capacity market auctions are conducted shortly before or during the capability periods for which capacity requirements are established so that most of the costs of having generating capacity available are sunk at the time the auction is run. Hence, the competitive offer price for new generating capacity in New York will reflect the costs that are avoidable in the time frame of the auction, which will typically be very low, regardless of how expensive the capacity was to build.

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52 By depressing the price of capacity in the spot auction, the construction of high cost capacity will also depress the price of capacity purchased in future strip and monthly auctions, whose prices reflect expected spot auction prices.

53 W. Hogan, "Minimum Offer Price Mitigation for the PJM Reliability Pricing Model", Affidavit included in PJM Power Providers Group, Answer to Motions to Dismiss and Other Pleadings, FERC Docket Nos. EL11-20-000 and ER11-2875-000, March 18, 2011.

This situation is different from the relationship between competitive offer prices and costs that would be expected to prevail in the forward capacity auctions in PJM and ISO New England, because in these regions most of the costs of new capacity are not sunk at the time the auction is conducted and, hence, are expected to be reflected in the offer price of a competitive supplier.[54]

The observation above regarding the impact of sunk costs on the relationship between competitive offer prices in the New York capacity auctions versus the forward capacity auctions conducted by PJM and ISO New England do not necessarily apply to demand response, insofar as the bulk of the costs of providing demand response are not sunk at the time of the capacity market auction. It is expected that most of the cost of deferring or forgoing power consumption is not incurred until consumption is actually deferred or forgone, so that offers for demand response in the capacity auction will tend to reflect the full cost of the demand response. However, this conclusion depends in part on the structure of the contractual relationship between the demand response provider and the end-use customer. It may be the case that some of the costs are sunk due to these contract terms, which could reduce the offers for demand response into the monthly capacity auctions in the NYISO.

This difference in the structure of the New York ISO capacity market relative to those operated by PJM and ISO New England does not change the potential for the exercise of buyer-side market power but does lead to differences in how the exercise of buyer-side market power should be identified and mitigated.

Section 23 (Attachment H) of the New York ISO's Market Administration and Control Area Services Tariff establishes market power mitigation measures that can be used to guard against the exercise of market power by those who buy ICAP in the In-City market and would benefit from a low capacity price. These mitigation rules provide that, unless exempt from mitigation, capacity offered by In-City ICAP

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54 Even in the PJM and ISO New England auctions some kinds of generating capacity with long construction lead times, such as coal or nuclear fueled generation, are expected to be offered in the forward capacity auctions at a price that is less than the plant's expected long-run cost.

suppliers, including new suppliers, must be offered in the spot market capacity auctions conducted each month by the New York ISO, at a price greater than or equal to the offer floor applicable to that capacity. The purpose of these rules is to prevent a supplier from offering capacity at a low price (presumably because it is under contract to, or under the control of, a net buyer of capacity), so as to decrease the clearing price in the capacity auction that applies to all of the capacity purchased by the net buyer.

The current In-City buyer-side mitigation rules consist of three parts: 1) those used to determine whether or not capacity offered by new entrants will be exempt from buyer-side market power mitigation bidding rules; 2) those used to determine the offer floor applied to the offers of non-exempt suppliers; and 3) those used to determine when and to what extent the offers of non-exempt suppliers will cease to be subject to buyer-side mitigation.[55]

2. Exemption from Buyer-Side Mitigation

A new supplier must pass one of two tests, A or B, in order to be exempt from buyer-side mitigation; these are equivalently described as the A and B triggers for the application of mitigation. Both tests are applied to all new In-City suppliers. Test A is designed to compare NYISO ICAP price forecasts to the economics of the demand curve proxy unit, while Test B is based on each new supplier's individual net cost of generation as evaluated by the New York ISO.[56] This report is focused on reviewing the appropriateness of the Test A and B triggers for buyer-side mitigation.

55 On Nov. 26, 2010 FERC approved several changes to the initial rules the New York ISO used to limit the exercise of buyer-side market power in its In-City capacity market. (133 FERC ¶ 16,178). The initial rules were accepted in New York Independent System Operator, Inc., 122 FERC¶ 61,122 (2008).

56 There is still an outstanding issue of the application of these rules to repowering; see "NYISO Board of Directors' Decision on Appeal of the Management Committee's August 25, 2010 Decision to Revise In-City ICAP Buyer-Side Mitigation", p. 3, filed with NYISO's September 27, 2010 FERC filing.

Test A exempts capacity offered by a new In-City supplier from buyer-side mitigation if the average In-City monthly ICAP price forecast for two successive capacity periods, where the first capacity period consists of the summer capability period three years from the start of the year of the class year of the supplier, is projected by the New York ISO to be higher, with the inclusion of the ICAP supplier, than the offer calculated by the NYISO for the same two capability periods.[57] For purposes of Test A, the offer floor benchmark is set at the Default net CONE, where Default net CONE is defined as 75 percent of Mitigation Net CONE. [58] Mitigation Net CONE is a capacity price calculated from the annual revenue requirement for the peaking unit used to anchor the demand curve for In-City installed capacity, including adjustments for inflation and excess capacity according to Commission-approved methods and factors.. Net CONE is the annual revenue requirement for the In-City demand curve peaking unit, which is the levelized embedded cost of this unit net of projections of the likely energy and ancillary services market revenue of the unit.[59]

The New York ISO tariff states that the model used to forecast ICAP spot market prices for the application of Test A will account for expected generation retirements that have been noticed to the New York State Public Service Commission. Existing generation supply, SCRs (demand response), UDRs (unforced capacity deliverability rights) and ICAP suppliers seeking exemption from buyer-side mitigation are all represented as price takers in applying Test A.[60] Thus, the forecast of the ICAP spot price is based on the intersection of a vertical (price-taking) supply curve with the ICAP demand curve. New capacity supply shifts the vertical supply curve applied in this test to the right, and will tend to lead to capacity price forecasts that are less than Default Net CONE, so that the supply will not pass Test A,

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57 Section 23.2.1 (Attachment H) of Market Services Tariff: "Mitigation Net CONE" shall mean the capacity price on the currently effective In-City Demand Curve corresponding to the average amount of excess capacity above the In-City Installed Capacity requirement, expressed as a percentage of that requirement, that formed the basis for the Demand Curve approved by the Commission. See also Section 23.4.5.7.4 (Attachment H) of Market Services Tariff.

58 New York Independent System Operator, "Buyer Side Mitigation Narrative and Numerical Example", August 2012, p. 2

59 Section 23.2.1 (Attachment H) of Market Services Tariff.

60 New York Independent System Operator, Market Services Tariff, Attachment H, p. 75-76 and New York Independent System Operator, "Buyer Side Mitigation Narrative and Numerical Example", August 2012, p. 6.

unless there is a material expected growth in electricity demand or a substantial quantity of expected generation retirements.

The assumption that all existing supply and demand is price-taking, which is used in forecasting capacity market prices for the application of Test A, is, in effect, an assumption that most of the costs of these resources are sunk, so that their bids and offers into the capacity market auction would be expected to be very low. The result of (or corollary to) this assumption is that the new capacity supply will not displace any existing supply or demand resources in the NYISO capacity market for purposes of forecasting prices for the two capability periods comprising Test A. This assumption may be reasonable for most existing generation supply, given the relatively short (capability period) time-step of the NYISO capacity markets intended to be represented in the Test A price forecasts. Most of the costs of existing generation may be sunk on a semi-yearly basis, so that it would be unlikely for it to be displaced by the offers of the new capacity supplier.

However, it is important to be aware of consequences of applying the price taking assumption to demand response for purposes of forecasting capacity market prices for Test A. Since Test A is applied to capability periods, the price-taking assumption implies that the costs of providing demand response are, for the most part, sunk over at least a six-month time span. It is not apparent that this will be the case, unless the nature of the contractual relationship between demand response providers and end use customers is such that the payments to the end-use customers are sunk semi-annually from the perspective of the demand response providers. If this is not the case, then we would expect it to be possible for new capacity supply to displace higher-priced demand response, and this should, in principle, be represented in the models used to forecast capacity market prices for Test A. The assumption that all existing demand response offers at $0.00 per megawatt-hour has the potential to make it much more difficult for new supply to pass Test A, as it means that the new capacity cannot displace high-priced demand response. The test requires that the forecast market price be higher than Default Net CONE assuming that all demand response continues to supply capacity, even after entry by the new supplier. It is not apparent that there is an easy fix to this problem, though, as it could be extremely difficult to accurately estimate the actual semi-annual offers that could be expected from demand-response.[61]

In applying Test A, Mitigation Net CONE is increased by a Commission-approved escalation factor for each year elapsed since the determination of Net CONE subsequent to the Commission's approval of an ICAP demand curve.[62] This escalation attempts to account for the impact of inflation on the comparison of Default Net CONE (i.e., 75 percent of Mitigation Net CONE) to the New York ISO's projection of post-entry capacity market prices.

The Test A determination of exemption from buyer-side market power mitigation is appropriately based on whether the *post-entry* ICAP market prices are predicted to be less than the estimated Default Net CONE, thereby taking into account the fact that because plant size is lumpy, entry of new generating capacity will generally reduce the capacity price below Mitigation Net CONE. Because the entry of new resources is lumpy, and most other capacity supply is essentially fixed (and offered at very low prices), the addition of even a single new unit would generally be expected to depress the spot auction clearing price from the level of Mitigation Net CONE to a level well below Mitigation Net CONE. It would be inappropriate to design and apply a test to determine whether or not to mitigate buyer-side market power without taking into account that even efficient entry would result in some material depression of capacity prices in the short-run.

61 The offers of demand response into the monthly ICAP auctions may not be a good indication of the price level required to support demand response on a continuing basis, because some or most of the costs of contracting with consumers may be sunk at the time the monthly auctions are conducted. Hence, the supply elasticity of demand response may be mostly reflected in larger or smaller quantities of price taking supply being offered based on expected clearing prices, rather than fewer offers clearing. This bidding behavior makes it somewhat difficult to account for the elasticity of demand response in forward looking mitigation evaluations.

62 New York Independent System Operator, Market Services Tariff, Attachment H, p. 78.

A new supplier is most likely to pass Test A if the new resource is a relatively small capacity addition in a period of demand growth when the capacity supply curve would otherwise clear at or above the anchor of the demand curve. Under these circumstances the New York ISO would be more likely to forecast that capacity prices would on average be above Default Net CONE in the test year because the price on the demand curve, even at the level of capacity inclusive of the new supply may be at a level above Default Net CONE.

If a capacity addition is large, however, such as the supply provided by a new combined cycle unit, it is unlikely that the resource would pass Test A unless the forecast ICAP market-clearing price would otherwise be well above the anchor price of the demand curve. A large capacity addition would otherwise be unlikely to pass Test A because the model used to estimate the price impact of the new supply includes its entire capacity at an offer price of $0.00 kW/month, which will typically cause the New York ISO's forecast of the capacity market price to fall.[63] Because Test A requires that the average forecast price with entry by the resource be above the Default Net CONE for a single test for a single year, larger units are less likely than small units to pass Test A.

The scale of the impact of a typical combined cycle unit on market clear capacity prices can be estimated for the May 2012 spot auction. Given the target capacity in the May 2012 spot auction, the entry of a 600 megawatt combined cycle would have reduced the Zone J clearing price from the level at the capacity target to 62.5 percent of target. The price impact from the entry of a combined cycle would likely be somewhat cushioned by some demand response displacement from the market as the capacity price falls, but it might not be possible for a combined cycle to enter these markets without driving the capacity price below the level of Default Net CONE, unless the new unit is at least in part replacing capacity that will be ceasing operation.

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63 The price impact of multiple capacity additions is modeled at the same time. See New York Independent System Operator, "Buyer Side Mitigation Narrative and Numerical Example", August 2012, Section 6.3, p. 10 and New York ISO Market Services Tariff Section 23.4.5.7.3.2 (Attachment H).

Combined cycle units that would drive the capacity clearing price below Default Net CONE if their entire capacity cleared in the market, can enter the Zone J market by offering their capacity at the offer floor and clearing a portion of their capacity in the initial year, and then clearing additional capacity in subsequent years. This bidding approach might allow entry by an efficiently sized unit, but would potentially entail power consumers paying for demand response or incumbent resources that would not in reality be needed since the entire capacity of the new combined cycle unit would be available to meet load even if only a portion cleared in the spot capacity auction.

The application of the 75 percent factor to the calculation of Default Net CONE from Mitigation Net CONE, as opposed to using a threshold of 100 percent of Mitigation Net CONE, potentially serves to provide an avenue for efficient entry to occur without buyer-side mitigation, given the lumpiness of generation investment. This is particularly important given that most of the investment in new capacity since 2005 has been in the form of combined cycles, whose larger size will have a larger short-run impact on capacity market prices than a gas turbine. The impact of scaling Mitigation Net CONE by 75 percent on the likelihood of exempting new suppliers from mitigation is an empirical matter; it is not apparent that there is a conceptual basis for assessing how this scaling will differentially impact different types of generating capacity or impact the risk of over- or under-mitigation of buyer market power.

The method for determining Net CONE and Mitigation Net CONE will affect whether or not any new generation is likely to pass Test A, as well as the relative chances that units of different types will pass the test. A November 2010 Order directed Net CONE to be set based on the costs of an LMS 100 peaking unit, which is a combustion turbine.[64] The ratio of the fixed to variable costs of such a unit will differ significantly from those for a combined cycle unit, and the estimated costs and revenues of the two types

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64 New York Independent System Operator, 133 FERC ¶ 61,178 at p. 2. Issued November 26, 2010.

of generation will consequently be impacted differently by changes in gas prices and other factors such as environmental restrictions on operation.

The reasonableness of the outcomes produced by Test A are heavily affected by whether or not Net CONE has been set at the appropriate value. It is noteworthy that if the estimate of Net CONE overstates the cost of entry and the demand curve is thereby anchored at too high a level, Default Net CONE will also be too high and this could make it difficult for suppliers to obtain exemption from mitigation under Test A. This could make it difficult for new suppliers to enter the market and drive the price of capacity down to the competitive level or keep it at a competitive level. The possibility of an overstated Net CONE would be particularly serious if the overstatement resulted from an inaccurate assumption that was also used in the calculation of the Unit Net CONE, which is a unit-specific estimate similar to Mitigation Net CONE, so that Unit Net CONE would also be overstated in the application of Test B. Conversely, if the estimate of Net CONE is too low, the offer floor would be set too low, which could make it possible for an entity with buyer market power to depress capacity market prices by contracting for uneconomic new supply.

While the Mitigation Net CONE calculation can be formalized with well-defined rules that produce a reproducible regulatory outcome, this does not mean that the assumptions used in the calculation will always accurately reflect the competitive cost of entry. The actual cost-based competitive offer price at any point in time depends on the expected path of future capacity market prices (which depends on the future time path of generating equipment prices as well as the growth of demand), expected future energy and ancillary service prices (which depend on many factors, including future fuel prices and environmental regulations), and a variety of assumptions regarding the cost of capital.

One way to diminish the potential adverse impact of an overstated Net CONE would be to provide an exemption from buyer-side market power mitigation for resources clearly lacking buyer-side market power, just as the New York ISO exempts the suppliers controlling a small quantity of ICAP capacity from seller-side mitigation at the time of the monthly ICAP spot market auctions.

Conversely, potential errors in measuring Net CONE also create the potential for uneconomic entry to be undetected and unmitigated if Net CONE is understated. One element of the Net CONE calculation that has a clear potential to result in understated estimates of Net CONE is the tariff requirement that the energy margin adjustment be calculated under the assumption that capacity is at the target level. Any time there is actually a capacity surplus, this rule would be likely to result in overstated estimates of energy and ancillary services revenue and an understated Net CONE for new capacity built during these surplus conditions, although the estimated net CONE would be appropriate when the capacity balance is at the target level. This misstatement is unlikely to have any material impact; however, as situations in which this rule causes Net CONE to be materially understated are by definition situations in which there is a capacity surplus and capacity clearing price will be less than the Net CONE in any case.

Test B exempts a new In-City supplier from buyer-side mitigation if the monthly average of the ICAP spot market prices in six capability periods, where the first capacity period consists of the summer capability period three years from the start of the year of the class year of the supplier, is projected by the NYISO to be higher with the inclusion of the new supplier than the reasonably anticipated Unit Net CONE of the new supplier.[65] In the modeling to project ICAP spot market prices for Test B, ICAP suppliers seeking exemption from buyer-side mitigation are assumed to offer at the minimum of Default Net CONE and their Unit Net CONE and all other supply and demand is represented as price-taking.

A combined cycle unit, or any other unit, would be exempt from mitigation under Test B if the New York ISO estimates that, on average, over a three-year period, ICAP prices would rise above the Net CONE of the unit (or Default New CONE, if lower) due to the growth of demand or unit retirements. The same

65 New York ISO Market Services Tariff Section 23.4.5.7.2 (Attachment H)

concerns expressed above regarding the assumption that all demand response is price-taking, for purposes of applying Test A for buyer-side mitigation, also pertain to Test B. The assumption that no demand response would be displaced over the three year time horizon of Test B is perhaps even more extreme, and could make it very difficult for new capacity supply to pass Test B even if the generation would be economic taking into account the willingness of loads to pay for this new supply rather than providing demand-response. The price elasticity of demand response supply has been apparent in response to recent declines in the price of capacity.

However, as previously mentioned, it is not apparent that there is an easy fix to this problem, as it would be extremely difficult to accurately estimate the actual semi-annual offers that could be expected from demand-response over a three year time horizon. If the participation of demand response in New York capacity markets increases in regions subject to buyer side mitigation, it would be desirable to find some method of at least approximately accounting for the likely elasticity of demand response supply in applying Test B.

Because the estimation of Mitigation Net CONE is based on a combustion turbine, the benchmark cost for Test A for a combustion turbine will always be less than the benchmark cost for Test B for a combustion turbine unless Net CONE is greatly understated for a particular unit relative to the combustion turbine costs used to set Mitigation Net CONE; i.e., Default Net CONE (Test A) is 75 percent of Mitigation Net CONE for the combustion turbine used to set the demand curve, so that Default Net CONE will always be less than Mitigation Net CONE for this unit. Therefore, it appears that the rules are designed so that the exemption determination for a combustion turbine generally would depend on whether the entry of the new resource is efficient in its first year of operation as it would pass Test A, which is based on 75 percent of Mitigation Net CONE and is a one year test, before it would pass Test B, which is based on the Unit Net CONE and is a three year test. The only circumstance in which a combustion turbine might pass

Test B and not Test A would be if the capacity price forecast trended up strongly in years 2 and 3, perhaps due to unit retirements or forecast demand growth.

3. Offer Floor for Non-Exempt Suppliers

The offer floor for suppliers that are subject to buyer-side mitigation is the minimum of 75 percent of Mitigation Net CONE (i.e., Default Net CONE) and the Unit Net CONE.[66] In 2008 the Commission defined CONE as the cost of adding the Demand Curve peaking unit to the In-City market and Net CONE as CONE minus an estimate of energy and ancillary services revenues (seasonally adjusted).[67] Since that time there have been a number of issues concerning the assumptions to be used in the estimation of Net CONE, especially around the level of excess capacity that should be used to determine expected energy and ancillary services revenue.[68]

The Unit Net CONE represents the levelized embedded costs of a specific new ICAP supplier (i.e. not the generic CONE unit), net of likely projected annual energy and ancillary services revenues and using an appropriate class outage rate.[69] The Unit Net CONE determination considers generation cost information provided by the new supplier. If it is a gas-fired unit, energy revenues for the first three years following entry are estimated based on projected gas future prices so as to represent the economics at the time the supplier is making a decision about whether or not to enter the capacity market.

A key and unavoidable limitation of the offer floor and the tests for exemption is that they are all based on estimates of Net CONE that may or may not reflect the actual cost of a new entrant. These estimates rest

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66 New York ISO Market Services Tariff Section 23.2.1, p. 9, (Attachment H)
67 New York Independent System Operator, 122 FERC ¶ 61,211 at p. 9. Issued March 7, 2008.
68 See New York Independent System Operator, 139 FERC ¶ 61,244, issued June 22, 2012, regarding the demand curve to use to determine Mitigation Net CONE; 135 FERC ¶ 61,170, issued May 19, 2011, regarding the issue of the excess capacity and the treatment of various costs in the calculation of Net CONE; and New York Independent System Operator, 122 FERC ¶ 61,211, issued March 7, 2008.
69 New York ISO Market Services Tariff Section 23.2.1 p. 9 (Attachment H).

on a number of assumptions that may or may not be accurate as discussed in Section IIA above. While entrants with low unit costs have the opportunity to demonstrate that they have actual costs that are lower than those assumed in calculating CONE, it is much more difficult for them to avoid inaccurate estimates resulting from the underlying methodology for calculating Net CONE, such as the use of levelized measures and forecasting methodologies that cannot accurately represent the impact on offers and prices of the variability of generation costs and revenues over time. Moreover, even the cost of a proceeding regarding the buyer-side mitigation analysis could discourage the construction of small, low cost resources.

A continuing problem with buyer-side market power mitigation based on minimum offer price rules is that the mitigated offer price affects both the opportunity for the offer to clear in the market, which affects the new seller, and the clearing price, which affects all existing sellers of capacity, assuming that the mitigated capacity is offered in the capacity auctions. This places a great burden on setting the correct mitigated offer price in order to deter the exercise of buyer-side market power. The impact of the offer price floor on capacity clearing prices magnifies the importance of correctly determining whether or not mitigation should be applied and to elaborate the many conditions that would be exceptions to the mitigation rule, so as to allow justification for different conditions and business plans of market participants.

By contrast, the alternative capacity price rule (APR) approach proposed by ISO New England, but rejected by FERC, as discussed further in Section IIIH2 below, separates the impact of the buyer-side mitigation rules on new resources clearing in the market from the impact on the clearing price applied to existing capacity resources. Under this approach, an error in determining the mitigated offer price has an effect on the price paid to existing resources, but it does not, at least directly, affect the incentives or ability of suppliers to enter the market. New generation capacity does not require an exception in order to offer or clear in the market. This separation of the impacts, and support of entry, addresses some of the most serious objections to buyer-side market power mitigation based on minimum offer price rules. In principle, there is little or no need for mitigation exceptions and more ability to apply rough justice rules of thumb in setting the mitigated price level.

4. Duration of Mitigation

The rules governing the duration of mitigation determine when a supplier subject to buyer-side market power mitigation will cease to be subject to the offer floor. The principle concern in the design of these rules is to find a balance, so that the rules that will not over-mitigate, thereby discouraging the entry of new economic generating capacity in New York City and, at the same time, will not under-mitigate, so as to allow the exercise of material buyer-side market power.

The duration rules proposed in the NYISO filing on September 27, 2010 contained four parts. In broad terms, the proposal included: a minimum period of mitigation (6 capability periods); a maximum period of mitigation (30 capability periods); a termination rule based on the forecast absorption of capacity surplus by demand growth; and a termination rule based on when the cumulative quantity of new supply that clears in the spot capacity market when offered at the bid floor is greater than the product of nominal UCAP and 12 (counting only months when over 50 percent of the resources' ICAP capacity (DMNC) clears in the capacity market).[70]

In a November 26, 2010 order, FERC accepted only the last of these criteria, with modifications.[71] FERC found that it was reasonable to base the duration of In-City buyer-side mitigation on the record of capacity clearing in the spot capacity market, when bid at the offer floor. However, the Commission

70 New York Independent System Operator, "Proposed Enhancements to In-City Buyer-Side Capacity Mitigation Measures, Request for Expedited Commission Action, and Contingent Request for Waiver of Prior Notice Requirement". Submitted September 27, 2010.

71 New York Independent System Operator, 133 FERC ¶ 61,178 at p. 16. Issued November 26, 2010.

found that the NYISO's proposal could result in under-mitigation because under the 50 percent benchmark for the fourth criteria, 100 percent of the suppliers' capacity could be released from mitigation even if at most 50 percent of the capacity cleared in the spot capacity market in any month.[72] To take the extreme case, if 50 percent of the capacity cleared in the spot market for each of 24 months, the supplier would meet the benchmark of clearing 100 percent of its annual capacity cumulatively in auctions in which at least 50 percent of its capacity cleared.

As ordered by the Commission, the NYISO made a compliance filing lifting buyer-side mitigation, for the minimum percentage of the new supply resource capacity that is cleared in 12, not necessarily consecutive, monthly spot capacity auctions.[73] As demand growth or other changes allow additional capacity to clear when offered at the mitigated price, this minimum level will rise over time, exempting an increasing percentage of the supplier's capacity from mitigation. These rules, which remain in effect, allow new supply that is initially subject to mitigation to gradually become exempt from mitigation without depressing capacity prices below the level used for mitigation.

The Commission stated that it preferred this after the fact methodology for phasing out the mitigation of non-exempt suppliers to the methodology based on the absorption of capacity surplus because was not subject to the "ambiguities and complexities" inherent in relying on forecasts of demand growth and other factors.[74] Thus, if demand were forecast to grow more quickly than it actually does, the third criterion might lift mitigation from a supplier's offers even though not all of its capacity would clear in the spot capacity auction at a price above the offer floor. This could result in capacity prices being driven below Mitigation Net CONE despite mitigation as a result of changes in market conditions such as recessions.

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72 The May 2010 In-City ICAP order (131 FERC ¶ 61,170), p. 42 previously lifted mitigation for new In-City SCRs when the capacity clears at the offer floor in 12 monthly auctions.

73 New York Independent System Operator, Compliance Filing and Request for Commission Action by April 1, 2011, in Docket No. ER10-3043-001. Submitted January 25, 2011.

74 New York Independent System Operator, 133 FERC ¶ 61,178 at p. 17. Issued November 26, 2010.

Although some market participants objected to the Commission-approved methodology on the grounds that it does not guarantee a mitigation period longer than a year and could therefore fail to hinder uneconomic entry, the Commission concluded that if the new capacity clears the spot capacity market for 12 months when offered at or above the offer floor, it no longer needs to be subject to mitigation.[75] Thus, the methodology in principle releases developers from a long period of mitigation if the capacity they develop is needed in the market. In contrast the capacity absorption methodology could continue to subject a supplier to mitigation if the supplier's forecast of the tightness of the capacity market was superior to the ISO's.

The methodology for determining the duration of buyer-side mitigation does not require the new capacity to be economic in every month, but does require it to be economic for a total of 12 months. This approach reasonably accommodates variations in market conditions. Although the Commission did not adopt the MMU's recommendations to separately assess the summer and winter capability periods[76], the approach sets the capacity that is no longer subject to mitigation as the minimum that has cleared for a total of 12 months.[77]

If demand falls or entry by other suppliers not subjected to mitigation occurs, the application of buyer-side mitigation could continue for some time under the approved approach to determining the duration. Some protests claimed that the lack of a maximum mitigation time posed an unacceptable risk for developers. However, the Commission considered the lack of an endpoint to be reasonable because, if the capacity is not accepted in the spot capacity market, there is a continuing need for mitigation.[78] If

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75 New York Independent System Operator, 133 FERC ¶ 61,178 at p. 18. Issued November 26, 2010.

76 New York Independent System Operator, 133 FERC ¶ 61,178 at p. 18. Issued November 26, 2010.

77 The offer floor is also seasonally shaped. See New York Independent System Operator, "Buyer Side Mitigation Narrative and Numerical Example", August 2012, p. 3.

78 New York Independent System Operator, 133 FERC ¶ 61,178 at p. 18-19. Issued November 26, 2010.

demand falls, mitigation reasonable needs to continue. Moreover, Unit Net CONE and Mitigation Net CONE are escalated for inflation every year under the Commission-approved methodology.[79]

An additional argument in favor of the approved methodology, as opposed the previous market rule based on the absorption of excess capacity, is that it allows new supply to be free of the offer floor when it economically supplies new capacity, even if this occurs because it displaces some existing capacity. In contrast, the absorption methodology determined the duration of buyer-side mitigation under the implicit assumption that new supply must serve only incremental load, since the absorption methodology only suspends mitigation when any excess capacity is absorbed by load growth, even if existing load is served by high cost capacity.

5. Considerations in Design of Tests for Buyer-Side Mitigation

The rules applied to mitigate In-City buyer-side market power have evolved as FERC and the NYISO have clarified the objectives of buyer-side mitigation and have worked these objectives into the mitigation rules. Among other things, recent orders have addressed adjustments for the escalation rate and inflation factors in the demand curves,[80] and escalation of the offer floor value determined at the time of a supplier's investment decision.[81] The decisions have generally moved in the direction of basing the test

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79 See New York Independent System Operator, Inc., 139 FERC ¶ 61,244 at 27-30. Issued June 22, 2012.

80 See, for example, 139 FERC ¶ 61,244 (2012) at p. 27-28: "because the intent is to compare the Unit Net CONE amount stated in one year's dollars to demand curve prices stated in dollars of three to six years in the future, it is necessary to restate, i.e., inflate the Unit Net CONE value in order to render a valid comparison in constant "real" dollar terms."

81 See, for example, 139 FERC ¶ 61,244 (2012) at p. 39-40: "we [FERC] will require NYISO to use values from the same demand curve that is effective at the time it makes an exemption determination in comparing Default Net CONE with spot market auction prices."

on actual market results rather than forecasts,[82] when possible, applying the tests consistent with the information available to investors at the point in time at which they make the investment decision in new capacity and attempting to maintain consistency between the Test A and Test B methodologies. For example, suppose that In-City capacity prices are estimated to be low, but an investor builds a new generator, because based on its own estimates it expects capacity prices to be higher than these estimates. If capacity prices subsequently rise, under the current rules, the minimum offer price for the supplier would not be adjusted upward, except for inflation, making it easier for the resource to qualify for the termination of any buyer-side mitigation, which is appropriate.

6. Conclusions

Application of buyer-side mitigation in a manner that deters or prevents the exercise of buyer market power in the capacity market is complicated by a number of considerations. First, as previously discussed, the estimated value of net CONE used to anchor the demand curve does not necessarily provide an accurate measure of the competitive cost of new capacity. Second, the competitive offer price for new supply typically will be very low in the New York design even in the absence of buyer-side market power, shifting the supply curve for capacity to the right and reducing the market-clearing price. Third, the lumpiness of new capacity investment and, especially, the large size of an efficiently-sized unit relative to the market in Zone J, means that even efficient entry may materially depress capacity prices around the time of entry. Fourth, changes in expected market conditions between the time a project's construction is determined and the time it is first offered in a capacity market auction, also can make a project's development look uneconomic in hindsight. Finally, it is difficult to determine a set of rules that

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82 See, for example, 133 FERC ¶ 61,178 (2010) at p. 17: "We [FERC] find that, although the capacity absorption concept that we previously accepted conceptually is a reasonable one for determining when new resources are likely to become economic, actually observing that the new capacity is accepted in the market at a price approximating its cost of entry, as reflected in NYISO's second duration methodology in proposed section 23.4.5.7(c) discussed below, is not subject to the ambiguities and complexities inherent in a method that relies on forecasts of load growth and other factors to estimate when the absorption of surplus capacity has occurred."

can be applied to generating units, such as combustion turbine and combined-cycle units, with potentially very different costs and capacities. The New York ISO's current rules for buyer-side mitigation are generally reasonable given the inherent challenges and the importance of not discouraging efficient entry or artificially inflating capacity prices through buyer-side mitigation rules that prevent capacity prices from being driven down to the competitive level when estimated Net CONE is overstated.

The buyer-side mitigation design has elements that attempt to reasonably account for the considerations described above, although it will inherently do so imperfectly. The decision about whether or not to mitigate offers from new supply is based on estimates of post-entry prices made at the time of the investment decision, not based on capacity prices after entry has occurred. In addition, Test A and Test B appear to provide avenues for capacity with different cost characteristics to obtain exemption from offer floor mitigation. Text B evaluates whether new supply will, on average, be in-merit in the capacity market over a three year period, rather than over the one-year period applied in Test A. A new resource, such as a combined cycle unit, might pass Test B if it has a Unit Net CONE that is less than Mitigation Net CONE, either because of lower unit costs or the expectation of higher energy and ancillary services revenues over a three-year period given its specific location and characteristics. In contrast, since Test A requires that the average forecast price after entry by the new supply be above the Default Net CONE for a single test year, larger units are less likely than small units to pass Test A. A new supplier will be most likely to pass Test A if the capacity addition is small, demand is growing, and/or the level of capacity in the market is close to or below the target level.

In addition, the test to determine when new suppliers will be exempt from mitigation takes into account changes in capacity market conditions relative to the time at which the investment was made. The test exempts new supply from mitigation as it clears in the capacity market when offered at the offer floor, without imposing a specified minimum or maximum period of mitigation. The test to determine when new suppliers will be exempt from mitigation also takes into account the impact of lumpy investment decisions on capacity market prices by allowing the new capacity to become exempt from mitigation over time, megawatt by megawatt, as more megawatts clear in the capacity market for the specified number of months.

Nevertheless, the New York ISO's buyer-side mitigation design also has elements that are inherently imperfect because Net CONE can at best provide a rough approximation of the capacity price at which new supply would be offered. The methodology and assumptions used will inevitably at times overstate (or understate) both Mitigation Net CONE and Unit Net CONE for particular new units. This will tend to deter efficient entry and inflate capacity prices (or permit the exercise of buyer-side market power through inefficient entry and depressed capacity prices).

One recommendation that would further diminish the potential adverse impact of overstated Net CONE would be to exempt from buyer-side mitigation resources owned and under contract to entities clearly lacking significant buyer-side market power, just as the New York ISO exempts suppliers controlling a small quantity of ICAP capacity from seller-side mitigation at the time of the monthly ICAP spot market auctions.[83] Such an exemption could be applied to new capacity depending entirely on spot market revenue, and to capacity resources entering into capacity or energy contracts to serve the load of municipals[84] or competitive retailers too small to potentially have any incentive to contract for uneconomic capacity in order to artificially depress capacity market prices. The current 500 megawatt threshold for exemption from seller market power mitigation would be a good starting point for establishing a similar exemption from buyer-side market power mitigation.

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83 See the discussion of the New York ISO's seller-side mitigation in Section IIIH1 below.

84 An explicit exemption for small municipals is not necessary with buyer-side mitigation limited to New York City as it is today but would be appropriate with the application of buyer-side mitigation to new zones, especially zones that my be created for municipal utilities and other small load serving entities clearing lacking buyer-side market power.

While the New York ISO does not normally have access to detailed information regarding bilateral contracts, it would be able to require that all such contracts be provided to the New York ISO as a condition for receiving this exemption.[85] While it would require some market monitoring unit resources to evaluate these contracts, it needs to be kept in mind that the alternative would be that the market monitoring unit and FERC would have to devote resources to applying (or evaluating the application of) the other much more complex exemption rules and potentially determining minimum offer prices for these resources.

This standard for exemption from buyer side mitigation could also be applied to exempt end use power consumers whose only compensation for providing demand response are the energy and ancillary service revenues and capacity payments received from the New York ISO. We do not, however, recommend a blanket exemption from buyer side mitigation. In particular, demand response procured by a market participant in exchange for payments that exceed the compensation provided for that demand response in New York ISO markets ought to be potentially subject to mitigation, as should demand response procured in exchange for payments that exceed the compensation provided for that demand response in New York ISO markets, with the difference recovered through some other mechanism.

We believe it would be very difficult for the New York ISO to measure the actual cost to end use power consumers of providing demand response, which is consistent with the recommendation to not subject demand response supplied by power consumers receiving compensation only from payments from the New York ISO to mitigation. However, this complexity does not exist when demand response is provided in return for a payment that exceeds the compensation provided for that demand response in New York ISO markets.

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85 Appropriate sanctions could also be established for failing to provide the New York ISO with a contract.

In addition, the New York ISO and its stakeholders should consider exempting from buyer-side mitigation resources supported by contracts entered into by load serving entities of any size for resources meeting the load serving entity's New York renewable portfolio standard requirements. We have two principal reasons for recommending that such resources be exempted. First, the capacity value of such resources is typically so low in relation to their cost that attempting to artificially depress the capacity market price by contracting for such resources would be so expensive that it is hard to conceive of such an effort being a profitable way to exercise significant monopsony power. Second, we believe that the amount of existing un-contracted for capacity meeting New York renewable portfolio standard requirements is too small in relation to the overall capacity market for it to be sufficiently beneficial to attempt to price discriminate against existing renewable resources in contracting for capacity.

Another limitation of the current mitigation design is that because the New York ISO capacity market is a current year capacity market with two six month capability periods, capacity that does not clear in the capacity market because of buyer-side market power mitigation has already been built and will be in operation. Hence, the capacity price determined when such capacity is excluded from the spot auction does not reflect the actual supply and demand balance and can send a signal for the construction of new capacity that is not actually needed.

Another potential change in the New York ISO design that would address this limitation would be to apply a mitigation design similar to that proposed as an "Alternative Capacity Price Rule" in New England, which would allow capacity offered below the buyer-side mitigation threshold and supported by an out of market contract or by ownership by an entity potentially possessing buyer-side market power, to clear and meet that entity's capacity obligation and determine the capacity price paid to new capacity suppliers but would not take that capacity into account in determining auction prices paid to existing capacity suppliers.

This kind of Alternative Capacity Price rule would be conceptually similar to a rule proposed for New England in 2010.[86] The purpose of the rule would be to permit resources supported by out of market contracts to participate in the capacity market and be used to meet capacity market obligations, without impacting the capacity price paid to existing capacity suppliers. Hence, those entering into such contracts would receive the benefit of the capacity they have contracted for, but the contracts would not provide the additional pecuniary benefit to buyers of lowering the price paid to purchase unforced capacity from existing suppliers in the market.

At a conceptual level, an "out of market contract" is a contract for, or an ownership investment in, new capacity that was uneconomic at the time the contract was entered into, or the ownership investment made. We have not attempted to spell out the details of the rules for classifying a contract as out of merit in this report, those details could be determined in a stakeholder process if this kind of approach were implemented.

This approach would be conceptually similar to the idea proposed by ISO New England when it stated:

> "OOM resources typically hold contracts that ensure full payment for the resource or otherwise receive particularized subsidies regardless of the capacity price that they could receive through their participation in the FCA [capacity auction]. Because OOM resources receive 'out-of-market' revenue, these resources can be offered into the FCA at very low prices that do not reflect a market-based or competitive cost of entry. OOM resources clear in the FCA on the basis of these low offers, and in so doing take the place of new or existing resources that offer in the FCA at competitive but higher prices. As a result, the FCA clears at a price (the 'Capacity Clearing Price') that is too low to retain or attract the displaced new or existing resources."[87]

While a competitive firm would not enter into such an apparently uneconomic contract or investment unless it had very different expectations regarding future market conditions than other market

86 First Brief of ISO New England, Docket Nos ER10-787-000 and EL10-57-000.
87 *ISO New England*, FERC Docket Nos. ER10-787-000, EL10-50-000 and EL10-57-000, First Brief of ISO New England Inc., July 1, 2010, p. 10.

participants, there is a potentially inefficient incentive to enter into such uneconomic contracts or investments because the lower clearing price that the OOM resources can cause to be paid for all resources clearing in the capacity market auction creates an incentive for the exercise of buyer market power. Hence, the inefficient incentive to enter into such uneconomic contracts or investments can be removed by rules which prevent such investments from impacting the clearing price for capacity that is paid to most suppliers, while allowing a buyer or investor to purchase the capacity and to benefit if its investment turns out to be profitable because the future unfolds in a way that was not expected.

This was the intent of the proposed New England alternative auction price rule which ISO New England similarly described as a follows:

> "way to correct for the effect of OOM resources is to establish the price that would have prevailed if the OOM resources had submitted competitive offers into the FCA – that is, the price that would have prevailed if these resources did not receive OOM revenues and had offered into the FCA at prices reflecting their full cost of entry. In this 'but-for' world, the FCA would clear based on the competitive but higher offers of the resources that were displaced by the OOM resources. This higher price, the Alternative Capacity Price, is established on the basis of resource bids that fully reflect their cost of entry. The Alternative Capacity Price thus fully corrects for the price-suppressing effect of some resources being OOM."[88]

While the kind of rules we describe would be conceptually similar to those proposed by ISO New England, they would be different in application because the ISO New England rules were intended to apply to a forward capacity auction in which the bulk of the investment associated with the new capacity had yet to be made and hence was not yet sunk. In the case of the mandatory monthly spot capacity auctions that the New York ISO clears against its capacity demand curve, presumably all generating resources participating in the auction will have been built and their costs are sunk. Hence an alternative auction price rule adapted to the New York ISO market seeks to create the right capacity price incentives for new entry decisions by basing the evaluation of potentially out-of-market contracts or investments on

88 ISO New England, p. 11.

the incremental costs and capacity market revenues that were projected at the time the contract or investment was entered into, rather than at the time offers were submitted to the capacity market auction.

As applied to the context of the New York ISO installed capacity market, the analogous application of an Alternative Capacity Price rule would clear each mandatory spot capacity market auction twice. In clearing the auction the first time, the offers of each prospective generator, both existing and new, would be accepted without regarding to whether it had been determined to be out-of-market, and the auction conducted with the standard offer caps and other installed capacity market rules but no minimum offer price mitigation. All the unforced capacity that clears in this auction would be selected to provide unforced capacity and would receive a capacity payment. The price in this auction would be referred to as the Initial Auction Price. Since the offers at this stage would not be subject to minimum offer price mitigation, the Initial Auction Price could be affected by any OOM offers. This Initial Auction Price would be paid to all new generation that cleared in this initial clearing of the auction, whether merchant or out-of-market.

The second clearing of the auction would utilize most of the same offers and other auction information, but the market monitor would replace any OOM-related offers for new or existing generation with a mitigated offer reflecting the offer floor determined by the New York ISO buyer-side market power mitigation rules. Therefore, the second auction clearing and its price would correspond to an auction in which the mitigated resources are treated as though they were offered at their costs in a forward market in which the generation construction and going forward costs are assumed to not be sunk in calculating the offer. This second clearing of the auction would determine the Alternative Capacity Price.

All existing generation that clears the second time the auction is cleared, i.e. in the mitigated auction, would be selected to provide unforced capacity and paid for its unforced capacity at the Alternative Capacity Price. Any mitigated existing generation that cleared in the first clearing of the auction but not the second time the auction was cleared would as noted above be selected to provide unforced capacity at the Initial Auction Price. Any new unforced capacity that cleared the second time the auction was cleared but not the first time, would not be selected to provide unforced capacity and would not receive a capacity payment. And, of course, new unforced capacity that did not clear either time the auction was cleared would not be selected to provide unforced capacity. Similarly, the unforced capacity of new generation that cleared in the first and second clearing of the auction would be paid the Initial Auction Price to discourage inefficient entry.

The Alternative Capacity Price rule would only be applied in the mandatory spot auction, i.e. the auction cleared against the demand curve. Bilateral capacity purchased in the voluntary auctions would not be certified for use in the NYCA if that capacity was supported by out-of-market contracts. This application of an Alternative Capacity Price rule would require rules to determine when new competitive resources would be converted and subsequently be treated like other existing resources. Presumably these rules would be the same as those the New York ISO currently uses to determine when a resource will no longer be subject to minimum offer price mitigation.

This is a summary of how the basic concepts of the New England Alternative Capacity Price proposal could be adapted to apply to the New York ISO installed capacity market. The two most distinctive features are that the auction design potentially involves two prices and the total capacity purchased could be more than would otherwise be purchased under the current NYISO approach to mitigating buyer-side market power in the capacity market.

The Alternative Capacity Price rule proposed by ISO New England was rejected by FERC in 135 FERC ¶ 61,209 April 13, 2011 for reasons that would not be applicable in the context of the New York ISO capacity market. In particular, that FERC order placed considerable weight on the fact that the New England design did not provide for the purchase of more than the minimum amount of capacity and that limiting purchases of capacity to the calculated minimum was a “bedrock” principle of the FCM model,[89] and contrasted this feature of the New England design with the demand curve models of PJM and the New York ISO.[90] The New York ISO capacity market demand curve, on the other hand, explicitly allows for the possibility of purchasing more, or less, than the target amount of capacity, so the purchase of only a minimum amount of capacity is not a feature of the New York ISO capacity market.

Another fundamental difference between the ISO New England and New York ISO markets that is relevant in this context is that ISO New England would be applying the mitigation and purchasing capacity in a forward auction. Capacity that did not clear in this forward auction as a result of minimum offer price mitigation need not be built and load serving entities need not pay for this capacity. Hence, FERC’s observation about whether it would be just and reasonable to require customers to incur unnecessary costs to purchase more capacity than the FCM was established to provide.[91] The New York spot auction, on the other hand, is conducted after any generating capacity found to be supported by out-of-merit contracts has been built and those costs are sunk. Hence, if the capacity does not clear in the auction the costs of the capacity are not avoided, whatever entity entered into the out-of-merit costs is bearing those costs. In addition, because the capacity has already been built and will be available to operate, New York transmission customers will receive the reliability benefits of having the additional capacity available, even if it is not allowed to clear in the spot market auction. Hence the issues on which the FERC Order on the ISO New England proposal appeared to rest are not applicable in New York.

The application of such an alternative capacity price rule in New York would have several negative consequences. First, when it was applied it would cause the New York ISO to purchase more capacity than the demand curve would prescribe at the alternative capacity price, since the amount purchased would be determined by the intersection of the demand curve with the lower Initial Auction Price. This

89 See Order at 160, 163-167
90 See order at 160 footnote 110 and at 164.
91 See Order at 163

would be an unavoidable consequence of such an alternative capacity price design as the difference in prices is the potential benefit from the exercise of buyer-side market power. Additionally, the amount of capacity purchased would actually be the same amount that would in fact be supplied if the auction were only cleared once at the Alternative Capacity Price because the capacity supported by the out of market contract would still exist. The investment in that capacity is long sunk in the time frame of the New York capacity market.

Second, while this design would avoid the inefficient entry of new generation or demand response resources, (because they would be paid the Initial Auction Price), it could result in the procurement of inefficient amounts of existing demand response resources and potentially existing generation resources. This inefficiency would be particularly likely for demand response resources which would not only be paid the higher Alternative Capacity Price, but these resources would incur lower interruption costs because they would face a lower likelihood interruption because of the supply provided by the mitigated generation resources. There would a similar distortion of the economics of keeping existing generation resources in operation but its impact would likely be less because the supply of existing generating resources would likely be less elastic than the supply of demand response in the relevant capacity price range.

A third potential negative consequence of such an Alternative Capacity Price design is that high cost existing generators and demand response resources would have an incentive to offer their capacity at artificially low prices, knowing that this would not impact the price they are paid but would reduce the price paid to new demand response resources and generation, discouraging efficient entry. In this situation the Initial Auction Price would not provide the signal for efficient entry.

A fourth potential negative consequence would be the need to exclude all new generation subject to being paid the Initial Auction Price from the voluntary auctions.

Another approach to applying buyer-side market power mitigation would be to mitigate out of market generation offer prices for the purpose of clearing the market in the capacity zones subject to buyer-side market power mitigation, but to allow the unmitigated capacity offer to clear in zones not subject to buyer-side market power mitigation, e.g. the NYCA capacity zone. This approach would recognize some of the reliability value provided by the resource subjected to market power mitigation (but not very much of its true value at current NYCA capacity prices) while preventing the offering of the resource from impacting the capacity price in the zones subject to buyer-side mitigation. This approach would not address the problem of sending an efficient signal for new entry, as the price in the mitigated zone would not reflect the availability of the capacity subjected to buyer-side mitigation.

There is no perfect solution to these various consequences of applying buyer-side market power mitigation. It is also unclear how material the potential for inefficient entry would be in practice unless the buyer-side mitigation applied to out of market generation were very long lasting.

D. Assessment of Demand Curve Slope and Crossing Points

1. Introduction

The New York ISO has asked us to evaluate in this report the New York ISO's capacity market demand curve with respect to: a) supporting orderly price formation; b) providing a proxy for demand elasticity; and c) reflecting the reliability value of capacity in excess of the reliability target. These considerations are related. If a demand curve that reflects the value of incremental generating capacity is used to clear the spot auction, this will ensure that the clearing price in the auction reflects the reliability value of incremental capacity. A demand curve for capacity defined in this manner will introduce demand elasticity into the auction because the reliability value of incremental capacity declines as the quantity of capacity under contract increases. Such a reliability-based demand curve will also tend to support "orderly price formation" by stabilizing the clearing price, relative to the clearing prices that would be determined by an absolute capacity requirement, i.e. a vertical demand curve.

Our conclusion is that it is appropriate for the New York ISO to clear its capacity market spot auction using a demand curve that reflects, as accurately as the New York ISO can reasonably measure it, the reliability value of incremental generating capacity. The slope of such a demand curve will serve as a proxy for the demand elasticity of New York power consumers and will also tend to stabilize clearing prices in the spot auction in a manner that will support orderly price formation. We do not recommend, however, that the New York ISO introduce more slope into the capacity market demand curve than is warranted by the reliability value of incremental generating capacity, nor do we recommend making the demand curve flatter than warranted by the reliability value of incremental generating capacity.

Illustrative calculations of the reliability value of incremental generating capacity indicate that the New York ISO's current demand curves provides a reasonable approximation of the value of incremental generating capacity, at least for capacity in excess of the target level,[92] with the current demand curve for the NYCA and Long Island (Zone K) perhaps a little steeper than warranted by the reliability value of incremental capacity (i.e. a demand curve based on the reliability value of incremental capacity would be slightly flatter) and the current demand curve for New York City (Zone J) perhaps slightly flatter than warranted by the reliability value of incremental capacity. However, in all three regions the current demand curves appear to be too flat for levels of capacity that are less than the target level, understating the reliability value of incremental capacity when there is a shortfall relative to the target.

92 By "target level" of capacity we mean the quantity of capacity used to anchor the demand curve. Some stakeholders prefer to refer to this as the minimum capacity requirement.

Subsection 2 discusses the origins of the demand curve for capacity and the conceptual reasons for expecting that the value of incremental capacity in excess of the target requirement will be less than the value of the target amount of capacity, but that the value of incremental capacity would not fall to zero for any excess over the target quantity; and conversely that when the available capacity is less than the target by even a small amount, the value of capacity will not rise immediately to the deficiency level.

Subsection 3 develops estimates of the reliability value of incremental capacity in New York and uses these values to construct illustrative capacity market demand curves.

2. The Reliability Value of Incremental Generating Capacity and the Design of the New York Capacity Market Demand Curve

a. Introduction

The introduction of a sloped demand curve in the New York ISO's capacity market in 2004 recognized that a fundamental characteristic of electric system reliability is the ex-ante uncertainty regarding the amount of generating capacity that will be needed to avoid involuntary shedding of firm load in any period, firm load being the load remaining after demand response has been activated and the demand response load removed from the system. This uncertainty exists in part because the actual peak load and the number of extreme high load days are not known at the time capacity needs are assessed because they depend on economic conditions, weather conditions, and how extreme weather conditions are correlated with other events. The uncertainty also exists because the actual level of generation and transmission outages on peak load days is unpredictable, as is the amount of supply that will be available from adjacent regions, which depends on the uncertain demand and supply conditions in those regions.

Because the amount of capacity that would be required to avoid load shedding is intrinsically uncertain at the time capacity requirements are determined, whether in a capacity market system, in a pool reserve requirement system or by an individual vertically integrated utility, it may be the case that more than the expected level of capacity may be required to avoid load shedding, or to avoid taking costly actions short of involuntary load shedding. Hence, capacity in excess of the amount projected to be needed to meet forecasted peak load has value in maintaining reliability. Conversely, this uncertainty also means that the amount of capacity that is sufficient to avoid shedding firm load, and to avoid taking other costly actions, may be less than projected, so even if the capacity committed to meeting load in the market is somewhat short of the target in any period, the value of incremental capacity is not necessarily equal to the value of lost load.

The sloped demand curve for capacity was introduced into the New York capacity market in order to recognize that capacity in excess of the target level can have material value to New York power consumers in terms of maintaining reliability, as well as to recognize that a small shortfall of capacity relative to the target does not necessarily result in adverse reliability outcomes.[93] Two other benefits of reflecting the value of incremental capacity in a sloped demand curve discussed in the development of the New York demand curve and in subsequent evaluations are its contribution to the stability of capacity market values and its contribution to reducing the incentive to exercise market power in the capacity market. The nature of these potential benefits and the merits of reflecting these potential benefits in the shape of the demand curve for capacity are discussed below.

93 Thomas Paynter, Docket ER03-647-000, April 11, 2003 p. 8; New York ISO, New York ISO filing of proposed Services Tariff revisions regarding an ICAP demand curve, Attachment IV-David Patton Affidavit, in Docket ER03-647-000 at p.5. Submitted March 21, 2003.

b. Stabilizing Capacity Prices

A benefit of reflecting the value of capacity in excess of the target level in the clearing price for capacity that was discussed in developing the New York demand curve was that the clearing price determined by the demand curve was expected to provide a long-term price signal which would reflect the need for capacity better than an absolute capacity requirement, i.e. a vertical demand curve for capacity. In particular, a sloped demand curve was expected to avoid the potential in a workably competitive market for a small excess of available capacity relative to the target level to result in near zero prices, given that most capacity costs are sunk in the time frame of the New York ISO capacity market auctions.[94] An advantage of a demand curve that recognizes that the value of incremental generating capacity moves along a continuum as the supply of capacity increases from a deficit relative to the capacity market target to a surplus relative to that target is that it will stabilize capacity prices, perhaps making it easier to finance investments in capacity and lowering the cost of capital.[95]

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94 See Paynter pp. 11-13; New York ISO, New York ISO filing of proposed Services Tariff revisions regarding an ICAP demand curve, Attachment IV-David Patton Affidavit, in Docket ER03-647-000 at p.5. Submitted March 21, 2003; Raj Addelpalli, Harvey Arnett and Mark Reeder, Regarding a Proposal by New York Independent System Operator Concerning Electricity Capacity Pricing. New York Assembly Standing Committee on Energy, March 6, 2003, pp. 5-7.

95 See, for example, Hobbs, Hu, Iñón, Stoft and Bhavaraju, A Dynamic Analysis of a Demand Curve-Based Capacity Market Proposal: The PJM Reliability Pricing Model. IEEE Transactions on Power Systems, Vol. 22, No. 1, February 2007, pp. 3-14.

However, in assessing the potential benefits that might come from defining the value of incremental capacity in a capacity market system so that the value differs from the reliability value of incremental capacity in order to stabilize the price of capacity, it is important to recognize that any load serving entity that wishes to stabilize the price it pays for capacity can do so more effectively by entering into a long term capacity contract that locks in the price of capacity over a 5, 10 or 15 year term, than by relying on the price stability provided by making the demand curve for capacity flatter than its actual reliability value.[96]

Hence the question can be posed: Should the New York ISO utilize a demand curve that does not reflect the actual incremental value of capacity if load serving entities and generators do not find it desirable to enter into contracts to stabilize prices in this manner?

One rationale for such intervention is the structure of the retail market for electricity in New York. Many residential customers are served by a default provider who may be unwilling to enter into a long-term contract for capacity to serve customers that could shift to another supplier leaving the provider unable to recover the costs of an out-of-the money forward capacity contract. However, this is less true now than when the capacity market demand curve was first implemented. Customers reflecting a substantial portion of New York power demand are now served by retail access suppliers, who could make or lose money by entering into a long-term contract for capacity to stabilize the price they pay.

It is important to recognize that the argument in favor of the New York ISO utilizing a demand curve in its capacity market having a flatter slope than warranted by the reliability value of incremental generating capacity because of its benefit in stabilizing capacity prices is implicitly based on a premise that the

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96 The capacity market demand curve has an impact on the hedge provided by bilateral contracts because the amount of capacity needed to cover a given load obligation can vary during the year depending on where the capacity market clears on the demand curves.

estimated cost of new entry used to anchor the demand curve will be centered on the long-run competitive cost of incremental generating capacity. If this is the case, short-run shocks that produce surpluses and shortfalls of capacity relative to the target level will produce capacity market-clearing prices centered on the estimated cost of new entry, and a demand curve that is flatter than warranted by the reliability value of incremental capacity will impact the stability of the capacity supply and clearing price but not their long-run level.

If, however, one takes the view, discussed above in subsection IIIA3, that the estimated cost of new entry is only a rough approximation of the actual competitive cost of incremental generating capacity and may systematically exceed or fall below the actual competitive cost of new supply, the rationale for utilizing a capacity market demand curve that is flatter than warranted by the reliability value of incremental capacity is much more doubtful. In that case, a flatter demand curve would not simply stabilize capacity prices and reduce variations in capacity supply around the optimal level but would cause the systematic procurement of more or less than the optimal level of capacity from a reliability standpoint.

In view of the sustained discrepancy between the actual clearing prices of capacity and the estimated net cost of new entry used to anchor the demand curve, particularly in upstate New York, and the potential for differences in assumptions and reference unit characteristics to produce large variations in the estimated cost of entry in downstate New York zones,[97] it is our view that there is a substantial potential for a demand curve that is flatter than warranted by the reliability value of incremental capacity to persistently result in power consumers contracting in the capacity market auction for more or less capacity than is warranted by its reliability value, rather than stabilizing the price and the amount of capacity procured near the level that is efficient from the standpoint of reliability.

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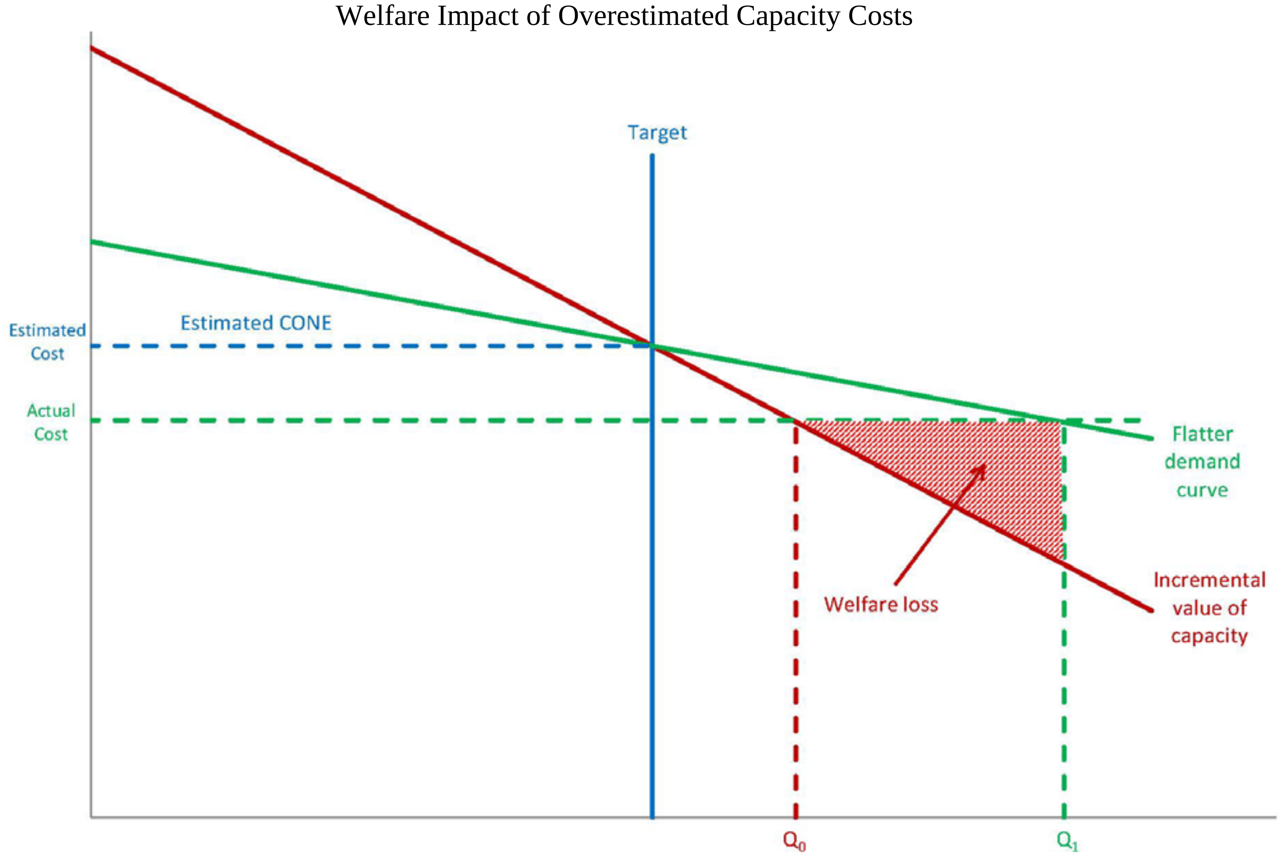
97 Such as the large differences in the estimated cost of entry arising from differences in the taxes imposed on the reference unit and other similar types of units that might be built to serve load.

The potential for an overestimated cost of capacity to cause society to incur more capacity costs than is efficient is illustrated in Figure 11, which shows the welfare loss from contracting for capacity whose value to society is less than its cost. The red line in Figure 11 is the estimated value of incremental capacity based on the perceived cost of new capacity, which is the dashed blue horizontal line. The horizontal dashed green line on the other hand reflects the actual cost of incremental new capacity. The lower cost of capacity would in this case cause the procurement in the spot auction of capacity in excess of the target level, denoted Qo in Figure 11.

Figure 11
Welfare Impact of Overestimated Capacity Costs

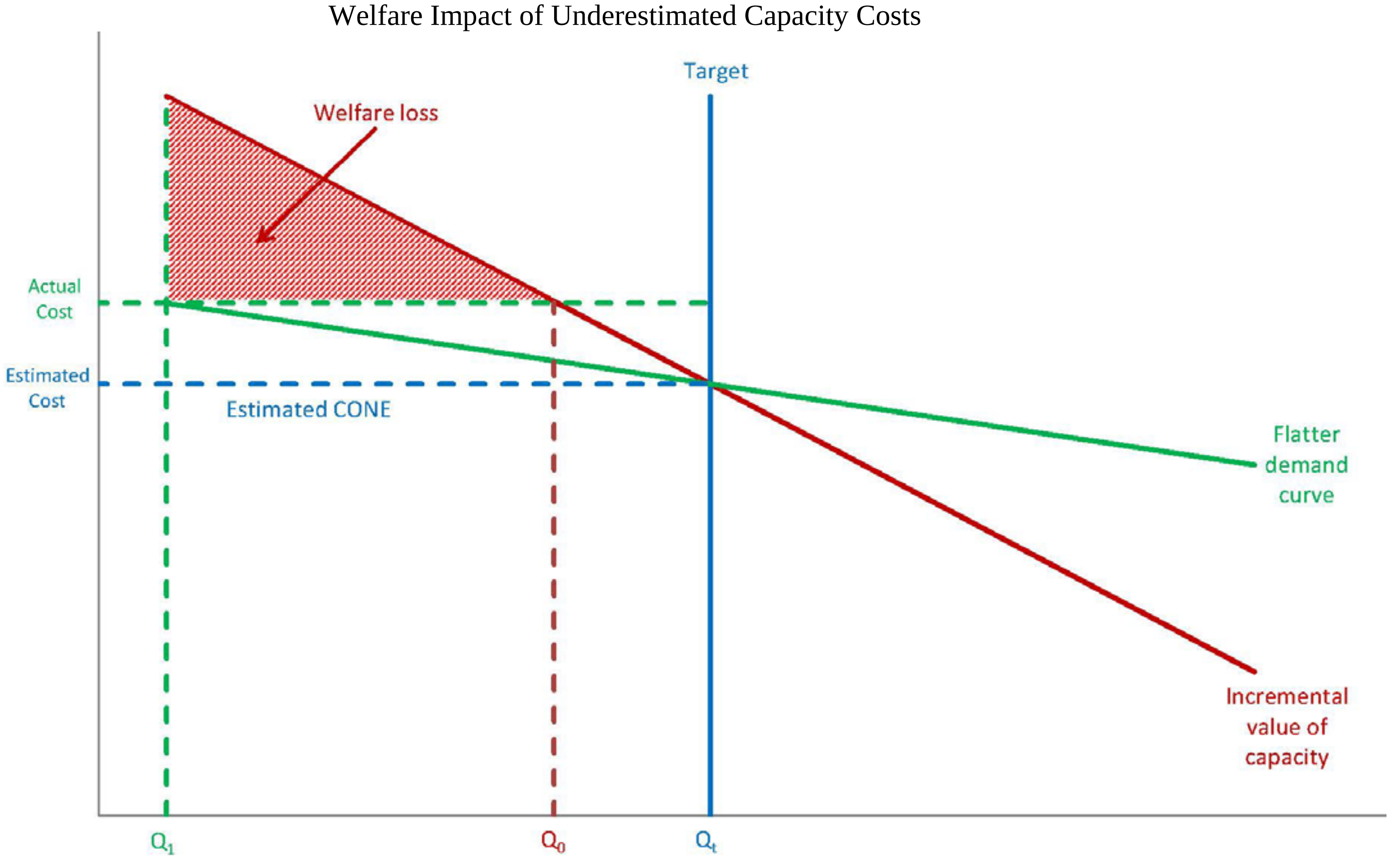


However, regardless of the quantity of capacity procured, the reliability value of the incremental capacity would equal its actual cost as long as the red line correctly reflects the value to society of incremental capacity.

Figure 11 also shows the welfare loss that would arise in this situation if the demand curve were made flatter than warranted by the incremental reliability value of capacity, as illustrated by the solid green line. While the flatter demand curve would result in the procurement of the target amount of capacity if the cost of incremental capacity were accurately estimated, and would result in small price changes for small variations in the amount of capacity offered relative to the target quantity, it would result in the procurement of a substantial amount of additional capacity if the actual cost of capacity were lower than estimated. This is illustrated by the difference between points Qo and Q1 in Figure 11, where the shaded red area measuring the welfare loss from the procurement of more capacity than warranted by its reliability value.

A flatter demand curve than warranted by the reliability value of incremental capacity would result in a similar reduction in welfare if the cost of incremental capacity were higher than assumed in setting the demand curve. This is illustrated in Figure 12 in which the actual cost of incremental capacity, the horizontal dashed green line, is higher than the cost assumed in setting the demand curve, the dashed blue line. This mismeasurement would over time result in the capacity market clearing with only Qo of capacity, less than the target Qt, but the incremental cost of capacity would equal its value to society as measured by the demand curve shown as the solid red line.

Figure 12
Welfare Impact of Underestimated Capacity Costs



If a flatter demand curve were used instead (portrayed by the solid green line) to clear the market, this would over time result in a much greater shortfall of capacity with only Q_1 procured, and would result in a large reduction in welfare (the shaded red area) because the actual value of incremental capacity (measured by the blue line) would be well above the green line.

Hence, we do not recommend that the NYISO establish a demand curve that is flatter than warranted by the reliability value of incremental generating capacity in order to achieve potential benefits from stabilizing the capacity price.

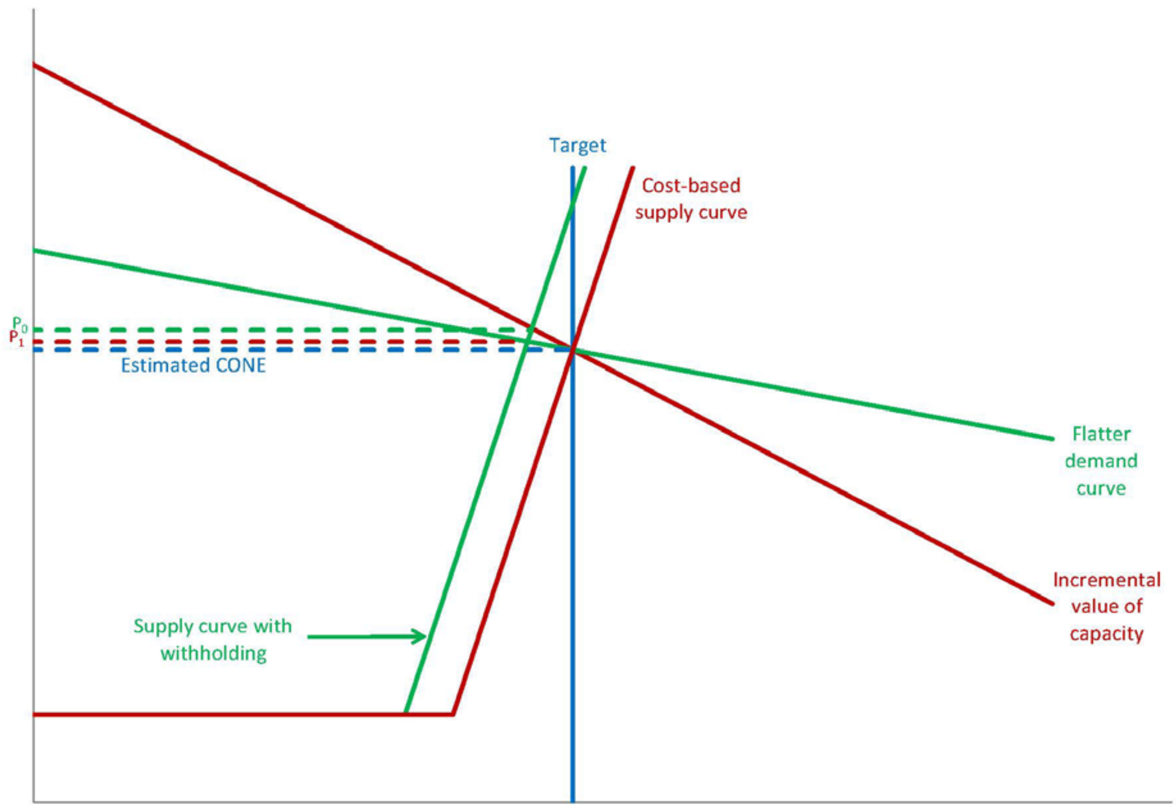
c. Market Power Mitigation

A second perceived benefit from implementing a sloped demand curve that is flatter than a demand curve based on the reliability value of incremental capacity is to reduce the incentive of suppliers possessing some degree of market power in the capacity market to exercise that market power.[98] Indeed, a demand curve for capacity that is flatter than warranted by the reliability value of incremental capacity will have some impact in reducing the profitability of an exercise of market power by capacity suppliers. With a flatter supply curve, a larger reduction in capacity sales would be required to produce a given increase in the price of capacity. The change in slope would cause the residual demand curve facing such a supplier to be more elastic than would otherwise be the case, making it less profitable for the supplier to withhold capacity from the market.

98 See Paynter p. 12, 18-19; New York ISO, New York ISO filing of proposed Services Tariff revisions regarding an ICAP demand curve, Attachment IV-David Patton, in Docket ER03-647-000 at p.8. Submitted March 21, 2003. Raj Addelpalli, Harvey Arnett and Mark Reeder, Regarding a Proposal by the New York Independent System Operator Concerning Electricity Capacity Pricing. New York Assembly Standing Committee on Energy, March 6, 2003, p. 5-7.

This is illustrated in Figure 13 in which the red line portrays the competitive supply curve and the green line the supply curve with some physical or economic withholding.[99] The short-run impact of the withholding would be to raise the price of capacity to Po on the demand curve reflecting the actual value of capacity but the price would rise only to P1 if the demand curve were made flatter.

Figure 13
Impact of Capacity Withholding



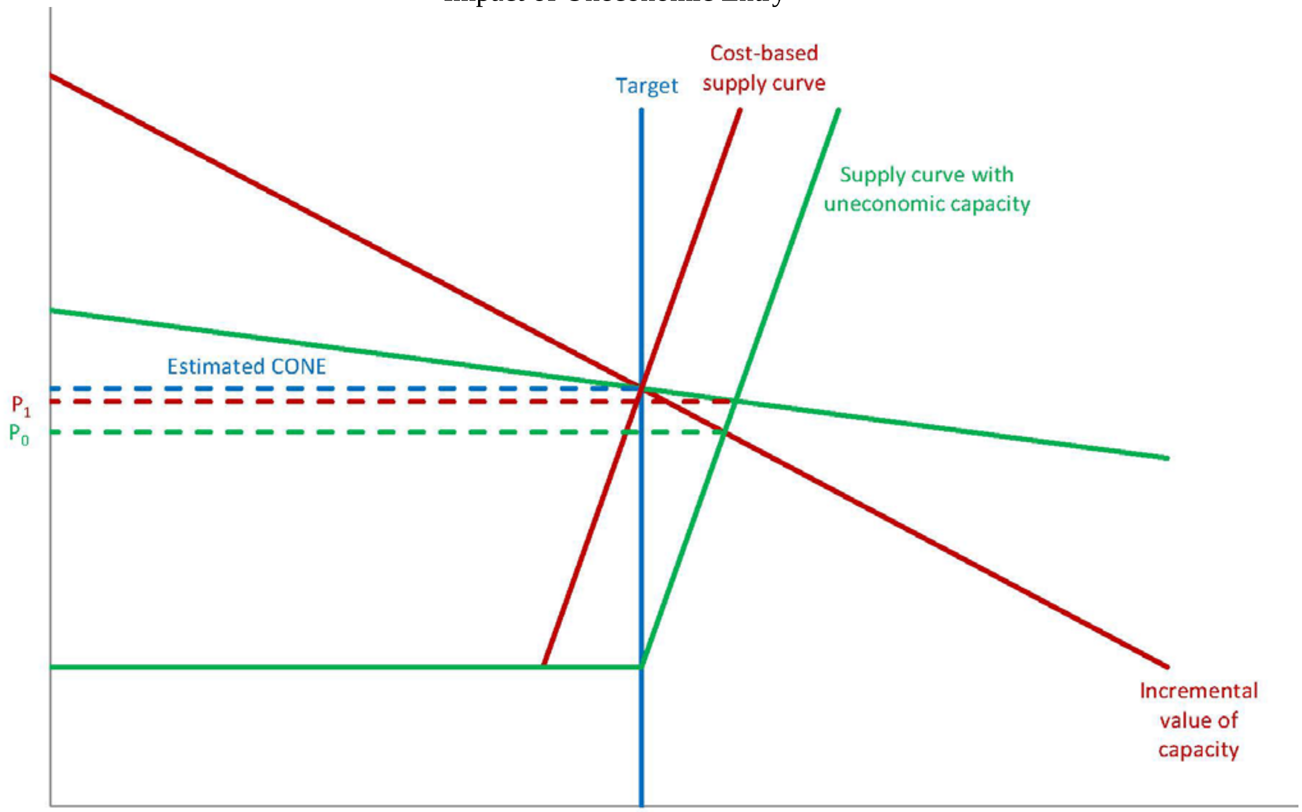
A demand curve that is flatter than warranted by the reliability value of incremental generating capacity would similarly have some impact in reducing the profitability of an attempt by capacity buyers to exercise market power by entering into bilateral contracts for the construction of uneconomic capacity at above market prices. The flatter the demand curve, the less profitable such an effort would be because the

99 The supply curves in Figures 3 and 4 are upward sloping, rather than horizontal as in Figures 1 and 2, because they are short-run supply curves. This reflects that fact that the short-run is the time frame relevant for analyzing the potential for the exercise of seller or buyer market power.

buyers would need to incent the construction of a larger amount of uneconomic capacity in order to produce a given short-term decrease in the spot price of capacity.

This is illustrated in Figure 14 in which the red line portrays the competitive supply curve and the green line portrays the supply curve with some uneconomic capacity. The short-run impact of the uneconomic entry would be to reduce the price of capacity to P_o on the demand curve reflecting the actual value of capacity but only to P_1 if the demand curve were made flatter.

Figure 14
Impact of Uneconomic Entry



If power demand were growing, this price impact would be very short-run, however, as the lower price of capacity would reduce competitive entry in subsequent years. Conversely, however, the flatter the demand curve, the more effective would be efforts to depress the price of capacity through misstatement of the cost of entry used to anchor the demand curve, and the flatter the demand curve, the longer lasting these impacts would be.

While the potential for a flatter demand curve to reduce incentives for the exercise of market power through the withholding of capacity by large net sellers or the construction of uneconomic capacity by large net buyers is a useful side benefit of a downward sloping demand curve for capacity that reflects the reliability value of incremental capacity instead of a fixed resource requirement, one needs to be cautious in using this potential benefit as a rationale for employing a flatter demand curve than is warranted by the reliability value of incremental capacity. A flatter slope than warranted by the reliability value of incremental capacity might somewhat reduce the incentive to exercise supplier market power; however, it would also mean that if there were no effort to exercise market power but the value of CONE were set too low, the shortfall or excess in capacity relative to the reliability target would be larger than it would otherwise be as discussed above.

As discussed in subsection IIA above, the value used to measure the "cost of new entry" is only an estimate of the long-run cost of capacity in a competitive market, and it is subject to a variety of measurement errors. If the estimated cost of new entry is lower than the actual long-run cost of incremental capacity, too little capacity will be purchased from the standpoint of reliability, even if the demand curve accurately reflects the reliability value of incremental capacity. If the demand curve has been made artificially flat in order to deter the exercise of market power, this welfare loss will be magnified.[100] Conversely, a flatter slope for capacity in excess of the target means that if the estimated value of CONE is too high, the capacity market will consistently contract for more capacity than is warranted by its reliability value.

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100 The Brattle Group, "Cost-Benefit Analysis of Replacing the NYISO's Existing ICAP Market with a Forward Capacity Market," July 15, 2009 p. 27.

It is also important to keep in mind that the welfare loss from the exercise of seller market power in the capacity market is not equal to the wealth transfer from consumers to generators associated with the high price, instead the economic (or physical) withholding causes society to procure too little capacity from the standpoint of reliability, so that there is some marginal capacity for which the incremental capacity value exceeds the marginal cost. While a flatter demand curve reduces the incentive for the exercise of market power and hence might reduce the welfare loss from the exercise of market power by large sellers through economic withholding, it would magnify the welfare loss from mis-estimation or manipulation of the cost of new capacity used to anchor the demand curve.

Another factor that needs to be taken into account in assessing whether it would be economically efficient to alter the slope of the capacity market demand curve to deter the exercise of market power is whether there are other mechanisms in place that constrain the exercise of seller or buyer market power to the extent that artificial adjustments to the slope of the demand curve in order to reduce incentives for the exercise of market power would provide relatively little benefit. An extensive set of rules relating to the exercise of seller and buyer market power in the New York capacity markets are in place today that were not in place at the time the capacity market demand curve was initially put in place. While the current market power mitigation mechanisms have a variety of limitations and imperfections, their existence greatly reduces the benefits from attempting to further reduce the potential for the exercise of market power by making the demand curve for capacity flatter than the reliability value of incremental capacity warrants.[101]

d. Conclusions

While we agree that reflecting the reliability of incremental capacity in excess of the capacity market target level in the slope of a demand curve for capacity used to determine the capacity requirement has

101 A similar observation has been made in NERA Economic Consulting, Independent Study to Establish Parameters of the ICAP Demand Curve for the New York Independent System Operator, November 15, 2010, p. 76.

some value in terms of providing a more stable price signal and potentially reducing marginal incentives for the exercise of buyer or seller market power, it is our view that shifting the slope of the demand curve for capacity so that it does not accurately reflect the actual reliability value of incremental capacity also has costs that need to be taken into account and balanced against the possible benefits. On balance, it does not appear to us that there is a case for adopting a demand curve that does not accurately reflect the reliability value of incremental capacity in order to achieve these other ends.

3. Estimating the Reliability Value of Incremental Capacity

a. Overview

This section discusses the estimation of a demand curve for capacity that measures the reliability value of incremental generating capacity in meeting firm load within the New York control area. The estimate is derived by assessing how the value of incremental capacity would change when the amount of capacity available is above or below the target.

One way to estimate the reliability value of incremental generating capacity needed to meet firm load would be to build it up from estimates of the value of increased reliability. This approach would necessarily involve estimating how each of the costs imposed on society by having inadequate generating capacity to meet firm load would increase or decrease with the availability or more or less than the target amount of generating capacity. These costs would include value of lost load when involuntary load shedding occurred, the costs of entering an emergency state and preparing for load shedding, the cost of voltage reductions, the cost of all the various actions that the New York ISO, the New York transmission owners, and local distribution utilities would have to take if the available generation were inadequate to meet NERC and NPCC reliability requirements, as well as potential broader impacts on Eastern interconnection reliability when the New York ISO is not able to maintain the target level of spinning reserve and regulation. This is a conceptually valid approach but it is not the approach we have taken in this report. Not only would it be difficult to assemble the information required to accurately calculate these costs, but no matter how carefully the approach is implemented it has the potential to produce estimates of the value of incremental generating capacity that are inconsistent with the assessments used to determine the target reserve margin and capacity price.[102]

Another way to estimate the reliability value of incremental generating capacity needed to meet firm load is to calculate the value of incremental generating capacity as reflected in the choices society has made for the target level of capacity. This approach assumes that the current capacity targets correctly take account of the value and cost of capacity. This is probably only roughly accurate but we take the view that it is best to determine a demand curve that is consistent with the value of capacity that underlies the current capacity target. If the target is not consistent with the actual reliability value of capacity, the appropriate solution would be to adjust the target, not to determine a demand curve for capacity that is inconsistent with the anchor point of the curve.

The NYISO's reliability standard, as determined by the New York State Reliability Council, calls for a Loss of Load Expectation (LOLE) to be no more than an average of one day in ten years.[103] This standard does not include any statement about the value of reliability. The fundamental characteristic of an ICAP demand curve is that the value of incremental capacity falls as more capacity is added to the system. Hence, to evaluate the reasonableness of a particular demand curve, it is necessary to have a least some approximation of the value of the reliability provided by incremental capacity.

Perhaps the simplest model consistent with the LOLE standard and the capacity market demand curve is an assumption that a loss of load event has a (large) fixed cost that does not depend on the size of the

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102 The impact of using an overstated cost of capacity to anchor the demand curve is illustrated in Figures 11 and 15.

103 New York Independent System Operator, Installed Capacity Manual Version 6.2. January 2012, p. 2-2.

excess of demand over supply, the amount of load shedding. This would be a zero-order approximation of a more complicated reliability cost function. With this assumption, the change in the expected value of the LOLE is only a function of the probability of an event, which is presumably decreasing in the amount of installed capacity. Since the probability of the loss of load event can be calculated, this simplified model provides one way to infer the value of reliability implied by the LOLE standard.

The starting point for this analysis is the assumption that:

[1] Incremental value of capacity = change in probability of load shedding with incremental capacity * cost of load shedding event

Given this assumption, the implied value of avoiding a load shedding event can be calculated as:

[2] Cost of load shedding event = Incremental value of capacity/change in probability of load shedding with incremental capacity

An important assumption underlying these equations is that the cost of a load shedding event is fairly constant over the range of probabilities that are evaluated. This is not a completely accurate assumption, however, because as available capacity is reduced not only does the probability of load shedding events rise, but more megawatts of load will have to be shed. This simplifying assumption can, however, be used to place a bound on the value of incremental capacity as discussed further in subsection b vi below. More accurate estimates of the reliability value of incremental generating capacity could be developed by using the GE-MAR[104] model to calculate the expected megawatt hours of load shedding (or expected unserved energy) associated with different levels of capacity but this information was not compiled in the preliminary analysis we carried out in conjunction with the New York ISO.

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104 GE Multi-Area Reliability Simulation.

Given this assumption, if we can measure the incremental value of capacity at the target capacity level and then calculate how varying the amount of capacity around the target level impacts the probability of a load shedding event, we can back out the implied cost of involuntary load shedding that is reflected in current reliability decisions.

This implied cost of an involuntary load shedding event can then be used in conjunction with calculations of how varying the amount of available generating capacity above and below the target level impact the probability of involuntary load shedding, to estimate the incremental value of generating capacity over ranges above and below the current target capacity level.

b. Conceptual Issues

We have identified six main complexities/underlying assumptions in applying this methodology.

- What is the incremental cost of capacity at the target level of capacity?
- What is the appropriate measure of a generation shortage event?
- How does incremental capacity impact the probability of a generation shortage event and the potential for load shedding?
- Does the cost of the target level of generating capacity reasonably reflect the incremental value of generating capacity?
- Does the incremental value of the target level of capacity reflect social benefits that are external to the New York transmission system i.e. that benefit consumers located elsewhere on the Eastern interconnection.
- Does the cost of a load shedding event rise with the amount of load shedding required?

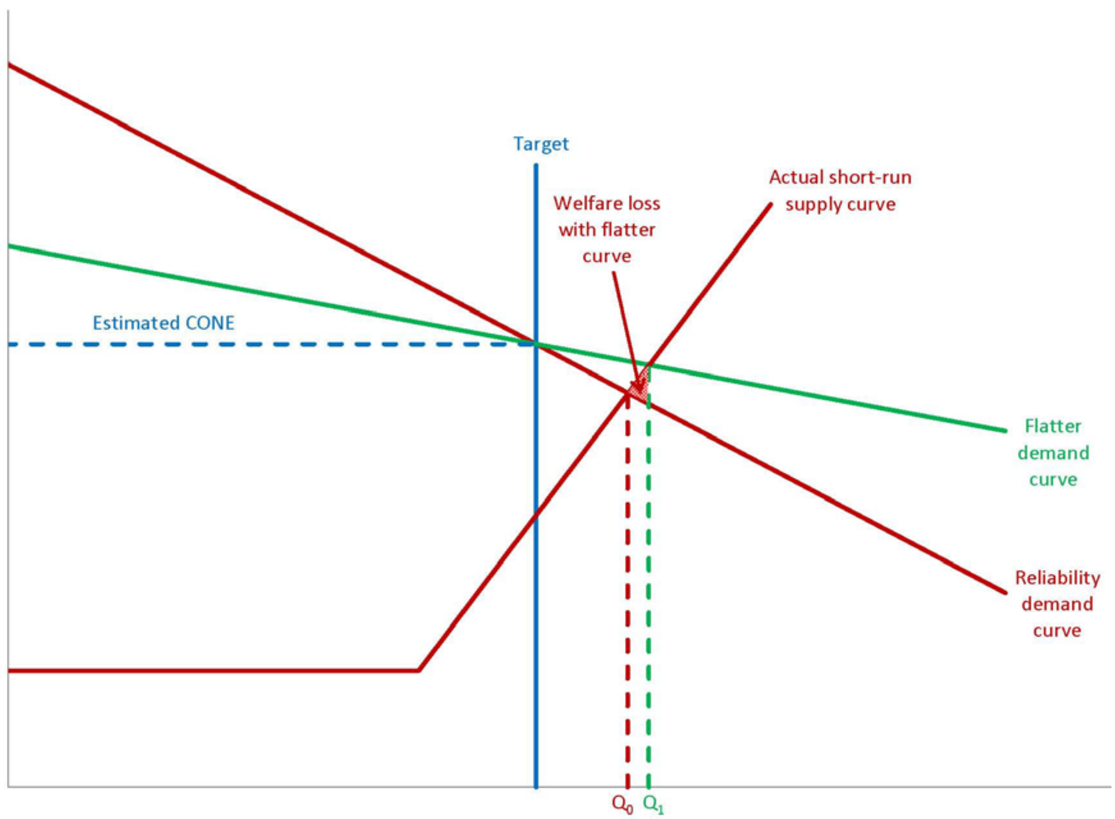
Each of these complexities, and our view of the appropriate way to resolve them, is discussed below.

i. Incremental Cost of Capacity

One possible measure of the incremental cost of capacity at the target level of capacity would be the estimated cost of new entry, net of energy and ancillary service revenues, which is used to anchor the New York ISO demand curve. This is the measure of capacity cost we use in this report. Although this measure has limitations as a measure of the actual long-run cost of incremental generating capacity, it is consistent with the design of the New York ISO capacity market demand curve, so it is relatively straight-forward to develop estimates of a reliability value based demand curve utilizing this measure of long-run capacity costs. In addition, even if this measure overstates or understates the cost of capacity in a particular region at a particular point in time, decisions concerning the target level of capacity may be premised on the assumption that the estimated cost of new entry reflects the long-run competitive cost of capacity and that it will be used to define the capacity demand curve, so it could be appropriate to base the demand curve on this perceived cost of capacity despite these potential over and understatements.

The potential impact of a misstatement of the actual cost of entry in defining a reliability-based demand curve is portrayed in Figure 15. If the capacity target was set based on the value and estimated cost of capacity (the dashed blue line in Figure 15) but the actual supply curve of capacity is lower in the relevant range (the red line labeled "actual short-run supply curve" in Figure 15 then the demand curve would still reflect the value of incremental capacity and there would be no welfare loss from the mis-estimation of the cost of incremental generating capacity.

Figure 15
Welfare Impact of Overestimated Capacity Costs and Misstated Value of Incremental Capacity



Alternatively, if the choice of the capacity target did not accurately reflect the value of incremental capacity (such as if the "flatter demand curve" in Figure 15 were used as the demand curve), then the use of a demand curve defined in this way could cause the New York ISO to procure too much capacity from the standpoint of economic efficiency, as also shown in Figure 15. In this scenario, however, it is noteworthy that it would still be the case that the use of a flatter demand curve than warranted by reliability premised on the misstated cost of new entry would lead to a much bigger error and much bigger reduction in consumer welfare, as also illustrated in Figure 15.

ii. Appropriate Measure of a Generation Shortage Event

This study has used the shedding of firm load (i.e. the load remaining after the activation of demand response) as the measure of a generation shortage event. While this is a common measure of a generation shortage event, it is not the only possible measure. There is also a generation shortage from the standpoint of resource adequacy when the NYISO is short of 30-minute reserves due to inadequate generating capacity (but not if the shortage is due to a lack of on-line capacity rather than total generating capacity as this would simply reflect a short term load forecasting error). Similarly, there is a generation shortage from the standpoint of resource adequacy when the New York ISO is short of total 10-minute reserves, a more serious shortage when the New York ISO is short of 10-minute spinning reserves, and an even more serious shortage when the New York ISO uses voltage reductions to maintain reserves.

The use of a single measure of reliability, the loss of load expectation, is an intrinsic limitation of the methodology we use to estimate the value of incremental capacity. Even if the NYISO carried out simulations of how variations in installed capacity impacted each of these measures, we would lack the information required to infer how each of these various dimensions of reliability has individually impacted society’s choice of the target level of capacity, so there is no practical alternative to using this single measure of reliability to calculate the reliability value of incremental generating capacity and it must simply be recognized that it is a limitation of the approach.

iii. Impact of Incremental Generating Capacity on the Probability of a Generation Shortage Event

These calculations are the most complex element of the study and were carried out by the New York ISO using the same methodology used to determine the loss of load expectation for the target level of capacity. The details of these calculations are explained below in the discussion of the methodology in Section IID5c below.

iv. Does the Cost of the Target Level of Generating Capacity Reasonably Reflect the Incremental Value of Generating Capacity?

The methodology in this report is premised on the validity of the assumption that New York's[105] decisions regarding the target level of capacity accurately reflect the incremental value of that capacity to society. If the current decisions regarding the target level of capacity are poorly informed relative to the costs and benefits of that level of generating capacity, then the estimates of the reliability value of incremental capacity developed in this report will not be accurate as illustrated in Figure 15 above.

However, while some may disagree with the current judgments of regulatory authorities regarding the appropriate level of electric system reliability, these costs reflect current judgments and until the social decisions embodied in those regulatory decisions are changed, we believe these are the appropriate costs to use in a study of this sort, i.e. we are taking society's current evaluation as a given, rather than basing the calculation of the demand curve on potentially inconsistent judgments of our own.

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105 By "New York" in this sentence we are referring to the collective decision making on reliability by a variety of entities reflecting the interests of New York power consumers, including the New York ISO, the New York State Reliability Council, the New York Public Service Commission, and other agencies or branches of the state government, all of whose decisions impact the reliability of the New York grid.

v. New York Benefits vs. External Benefits

If the target level of generating capacity determined by the New York ISO and New York regulators is constrained from being set lower than the target level by federal regulators or industry reliability organizations, then it is possible that the incremental value of the target level of generating capacity we calculate could reflect social benefits that are external to the New York transmission system, i.e. that benefit consumers located elsewhere on the Eastern Interconnection. If this is the case, then at the target level, incremental capacity might provide less value to New York power consumers that than its cost, but the target could still correctly measure the level of capacity that maximizes the overall value of capacity to society.

vi. Cost of Load Shedding Events

The implicit assumption underlying equations [1] and [2] that the cost of a load shedding event does not change with the level of capacity is clearly not accurate. Changes in available capacity that change the probability of load shedding also change the amount of shedding. Suppose, for example that with 36,000 megawatts of capacity the expected probability of a load shedding event is .061 days per year. A reduction in capacity to 35,900 megawatts not only somewhat increases the probability of a load shedding event, but increases the amount of load shed during those .061 days by the expected availability of the 100 megawatts of capacity during the loss of load hours and may also extend in time the loss of load hours.[106] A more accurate way to measure of the value of incremental capacity would be to account for not only the change in the probability of load shedding on a daily basis but the change in the expected megawatt hours of load shedding.

106 The change in the amount of load shedding would be less than 100 megawatts because the expected availability of capacity would not be 100 percent during load shedding events. In fact, because a load shedding event is likely to be correlated with higher than expected outage rates, the change in the amount of load shedding would likely be less than the amount of UCAP removed.

The demand curve estimated based on equations [1] and [2] does, however, bound the demand curve defined based on the expected megawatt hours of load shedding. First, the point at which incremental capacity has no impact on the probability of load shedding should be the same as the point at which incremental capacity has no impact on the megawatts of load that is shed because both are the point at which incremental capacity does not impact load shedding. Hence, the lower end of the demand curve should be the same under either approach.

Second, the anchor of the demand curve is not impacted by the megawatt amount of load shedding because the anchor is determined by the target level of capacity and the estimated Net CONE. While society's choice of the target level may be impacted by the expected megawatt hour amount of load shedding given the target amount of capacity, we do not need this information in order to determine the anchor point. Between these two points, the anchor of the demand curve and the point at which incremental capacity has no incremental reliability value, the impact of accounting for the megawatts of load shedding would be to make the actual value of incremental capacity more non-linear, i.e. decreasing more rapidly with increases in capacity, than the curve estimated using equations [1] and [2].

Third, for levels of capacity less than the target level, the impact of accounting for the megawatt hours of load shed would be to increase the cost of each successive reduction in capacity because more and more capacity would be shed, so the actual value of incremental capacity would be steeper below the target level than the curve estimated using equations [1] and [2].

c. Detailed Implementation

i. Overview

The derivation of a reliability-based demand curve has four steps. The first step is to use the New York ISO's GE-MARS model to estimate the NYCA loss of load expectation associated with varying levels of capacity in each capacity market region. The second step is to use this data to derive the change in the NYCA loss of load expectation associated with an incremental change in the level of capacity within each capacity market region. The third step is to use the estimated relationship between changes in capacity and changes in NYCA loss of load expectation at the target capacity level to calculate the implied cost of a loss of load expectation event. The fourth step is to use these implied costs of a loss of load event to derive reliability-based demand curves for each capacity market region. It will be seen that these reliability-based demand curves are generally very similar to the current demand curve except that they are steeper for shortfalls in capacity below the target level and some are slightly flatter above the target level (have a zero crossing point with more capacity in the case of NYCA and Zone K) or slightly steeper above the target level (have a crossing point with less capacity in the case of Zone J) than the current demand curves.

ii. Analysis of Reliability and Capacity

As discussed above, the most complex part of this study was the analysis of the relationship between incremental generating capacity and New York electric system reliability. This analysis was carried out by the New York ISO using essentially the same methods and models that are used each year to determine the target level of capacity for the capacity market.

The GE-MARS model used for NYISO capacity market simulations and for this study employs a sequential Monte Carlo simulation to calculate the reliability of the New York ISO electric system. In carrying out this simulation, GE-MARS models zonal generation and load and inter-zonal transfer capability but does not model intra-zonal transmission constraints. It is therefore a tool appropriate for analyzing the relationship between reliability and the zonal distribution of load and generation but cannot be used to examine the impact on reliability of generation pockets or load pockets located within the zones. That is appropriate for the purpose of this analysis.

The evaluation of the impact on New York reliability of increasing (decreasing) the amount of capacity in NYCA is carried out by increasing (decreasing) the total amount of generation in Western Zones A, C and D. [107] Capacity in the east is held constant. When evaluating the impact on New York reliability of additional capacity in Zone J, the capacity added in Zone J is removed from Zones A, C and D, so that total NYCA capacity is held constant.[108] Conversely, when evaluating the impact of having less capacity in Zone J, the capacity removed from Zone J is added in Zones A, C and D so that total NYCA capacity is held constant.[109] The same methodology is applied when varying capacity in Zone K or the Lower Hudson Valley.[110]

The proposed approach to calculating these local capacity requirements is that the NYCA loss of load expectations will be calculated as a function of the local capacity requirements and the NYCA reserve margin and the Tan 45 methodology used to determine the anchor point for the tradeoff between local capacity requirements and the overall capacity margin. The Zone J and Zone K local capacity requirements would be held constant when calculating the impact of changes in the Lower Hudson Valley

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107 This is implemented by adding load in these zones to reduce net generation or removing load to increase net generation, so there is no need to add hypothetical generating units with hypothetical outage characteristics.

108 Capacity is not removed from Zone B in this evaluation because of the potential for this to create a load pocket in Zone B, rather than measuring the value of additional capacity in the east.

109 As for NYCA, this analysis is implemented by increasing or decreasing load to change net generation within the zone without changing the mix of generation resources.

110 A Lower Hudson Valley region composed of load zones G, H, and I was analyzed to provide some insight into the possible shape of a reliability-based demand curve for such a new capacity zone.

capacity on NYCA loss of load expectations. The Tan 45 methodology will be applied to determine the tradeoff between Zone J capacity and the NYCA margin, between Zone K capacity and the NYCA margin and between Zones G, H, and I capacity and the NYCA margin.

The current NYISO method for estimating the ICAP demand curve conceptually involves shifting a fixed amount of ICAP, i.e. nominal capacity, between zones as described above. In concept, this ICAP is then converted to UCAP based on the average UCAP ratio for each zone so that the new capacity has the average availability characteristics of the current capacity in the zone. This conceptual approach is implemented in practice by adding an amount of load times the UCAP ratio of that zone to the load of the zone from which capacity is being subtracted, and subtracting from the load of the zone to which capacity is being added the same amount of load times the UCAP ratio of that zone.[111] This methodology has the effect that when ICAP is shifted between zones in the NYISO analysis to calculate the local reliability impacts, the amount of load/UCAP shifted into one region can be different than the amount shifted out of the other region, so that the shift changes the aggregate amount of capacity available.

While this methodology can produce results that appear anomalous, if one thinks of a specific resource being shifted from one capacity market region to another, the methodology makes sense from the perspective that the various capacity market regions have different resource mixes and that shifting capacity requirements from one region to another region will likely not simply result in the same type of unit being built in a different location but will result in a different type of unit being built. These ambiguities are intrinsic to a capacity market system in which the capacity requirement is defined in terms of nominal capacity.[112]

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111 By changing the net load across zones the methodology alters the net capacity margin in the impacted zones as if capacity was added of subtracted, without the need to add or remove particular generating units with particular outage rates.

112 See also Scott Harvey, “Resource Adequacy Mechanisms: Spot Energy Markets and Their Alternatives,” June 28, 2006 p. 30, 101-104.

In the context of the current analysis we have calculated the approximate impact of these ICAP/UCAP assumptions when ICAP is shifted between upstate and downstate New York. The weighted average forced outage rate for ICAP shifted out of Zones A, C and D is roughly 12.2 percent while the rate for Zone J is 10.2 percent; Zone K's rate is 10 percent and the Lower Hudson Valley's rate is 6.2 percent. Hence, there is a small change in the total amount of UCAP available in the NYCA when capacity is shifted between these regions. As noted above this would not accurately reflect the impact of shifting a given unit between the West and Zone J, capacity in Zone J is on average different from capacity in the West, so in this context it makes sense to attempt to account for the different UCAP values in the two regions, while recognizing that it is ultimately the UCAP value of the marginal generation resources in which region that are relevant. While this methodology does not account for such differences in the UCAP value of the marginal units in the various zones, these kinds of ambiguities are intrinsic to a capacity market system defined in terms of nominal capacity. In this study we have not attempted to resolve those ambiguities which exist in the current design, but have tried to maintain internal consistency between the methodology used to estimate the capacity market demand curve and the method that we use to estimate the reliability value of incremental capacity.[113]

113 The effects are also likely very small in the context of this study. The difference between the 100 percent and 103 percent Zone J ICAP requirement is 286 megawatts. The difference between the UCAP value of these 286 megawatts of ICAP in Zone J and the West is 5.64 megawatts of UCAP. This is 6.42 megawatts of ICAP at the Western UCAP ratio, and the impact of 6.42 extra megawatts on the loss of load expectation for the NYCA is roughly .0002, which is 3.2 percent of the loss of load probability impact of the 286 extra megawatts in Zone J.

Table 16 reports the capacity amounts and their associated percentage of the target capacity requirement for each region used in the loss of load evaluation.

Table 16
Capacities in Loss of Load Analysis

Percentage of Requirement	Capacity			
	NYCA	NYC Zone J	Long Island Zone K	Zones G H I
90%	34,761.0	8,590.5	4,923.3	13,412.7
93%	35,919.7	8,876.9	5,087.4	13,859.8
95%	36,692.2	9,067.8	5,196.8	14,157.8
98%	37,850.9	9,354.1	5,360.9	14,604.9
100%	38,623.4	9,545.0	5,470.3	14,903.0
103%	39,782.1	9,831.4	5,634.5	15,350.1
105%	40,554.5	10,022.3	5,743.9	15,648.1
108%	41,713.2	10,308.6	5,908.0	16,095.2
110%	42,485.7	10,499.5	6,017.4	16,393.3
113%	43,644.4	10,785.9	6,181.5	16,840.4
115%	44,416.9	10,976.8	6,290.9	17,138.4
118%	45,575.6	11,263.1	6,455.0	17,585.5

Table 17 reports the NYCA loss of load probability, calculated in terms of events per year as calculated by the NYISO in its loss of load simulation studies.

Table 17
Estimated Loss of Load Probabilities

Percentage of Requirement	NYCA Loss of Load Probability			
	NYCA	NYC Zone J	Long Island Zone K	Zones G H I
90%	0.583	0.305	0.251	0.475
93%	0.324	0.207	0.177	0.277
95%	0.226	0.166	0.147	0.195
98%	0.133	0.118	0.114	0.125
100%	0.100	0.100	0.100	0.100
103%	0.074	0.082	0.083	0.080
105%	0.068	0.075	0.076	0.074
108%	0.055	0.066	0.068	0.072
110%	0.046	0.064	0.064	0.072
113%	0.044	0.063	0.059	0.074
115%	0.044	0.064	0.057	0.078
118%	0.044	0.065	0.056	0.090

iii. Reliability Impact of Incremental Capacity

The information in Tables 16 and 17 can be used to calculate the estimated impact on NYCA reliability of incremental generating capacity, both in the NYCA and in each of the regions. These calculations are reported in Tables 18 through 21.

These tables are structured so that the top two rows (A and B) report the capacity and loss of load probability information for the reserve margins studied in the analysis, as reported in Tables 16 and 17. Then row C calculates the change in NYCA loss of load probability associated with a change in available capacity. For the columns to the left of 100 percent, the change is calculated from moving to that reserve margin from a lower margin. For the columns to the right of 100 percent the change is calculated for moving from a higher margin to a lower margin. Thus, the change in LOLE under 103 percent in Table 18 for NYCA is the difference between 0.1 LOLE at 100 percent and 0.074 LOLE at 103 percent, or 0.026.

Row D similarly calculates the change in generation, so the 1159 under 103 percent is the increase in capacity moving from 100 percent to 103 percent of the target level of capacity. Finally, Row E calculates the ratio of the change in NYCA loss of load probability to the change in capacity, i.e. the change in loss of load probability due to a 100 megawatt change in capacity. The ratio is calculated per 100 megawatts rather than per megawatt simply to avoid a large number of decimal points in reporting the values. The values reported in rows C, D and E under the target level of capacity (100 percent) are defined similarly, but are calculated over the range from 98 percent to 103 percent of the target capacity, bracketing the target level.

Table 18
NYCA Ratio of the Change in LOLE to the Change in Capacity per 100MW

		Percentage of Target Capacity Requirement											
		118%	**115%**	**113%**	**110%**	**108%**	**105%**	**103%**	**100%**	**98%**	**95%**	**93%**	**90%**
[A]	Capacity	45,576	44,417	43,644	42,486	41,713	40,555	39,782	38,623	37,851	36,692	35,920	34,761
[B]	LOLE	0.044	0.044	0.044	0.046	0.055	0.068	0.074	0.100	0.133	0.226	0.324	0.583
[C]	Change in LOLE	0	0	0.002	0.009	0.013	0.006	0.026	0.059	0.033	0.093	0.098	0.259
[D]	Change in Capacity	1,159	773	1,159	773	1,159	772	1,159	1,931	773	1,159	773	1,159
[E]	100 * [C]/[D]	0	0	0.0002	0.0012	0.0011	0.0008	0.0022	0.0031	0.0043	0.0080	0.0127	0.0224

Tables 19, 20, and 21 are constructed similarly and report analogous calculations for Zone J, Zone K and the lower Hudson valley. It can be seen in Tables 19 and 21 that at high levels of capacity in New York City and Lower Hudson Valley the change in NYCA loss of load expectation becomes negative. Our understanding from discussions with the NYISO modelers of the reasons for this outcome is that when this amount of capacity is shifted out of the West, Zones A and B become a load pocket and shifting additional capacity out of Zone A into J, K or Lower Hudson Valley causes an increase in loss of load probability in Zones A and B.

Table 19
New York City Ratio of the Change in LOLE to the Change in Capacity per 100 MW

		Percentage of Target Capacity Requirement											
		118%	**115%**	**113%**	**110%**	**108%**	**105%**	**103%**	**100%**	**98%**	**95%**	**93%**	**90%**
[A]	Capacity	11,263	10,977	10,786	10,500	10,309	10,022	9,831	9,545	9,354	9,068	8,877	8,591
[B]	LOLE	0.065	0.064	0.063	0.064	0.066	0.075	0.082	0.100	0.118	0.166	0.207	0.305
[C]	Change in LOLE	-0.001	-0.001	0.001	0.002	0.009	0.007	0.018	0.036	0.018	0.048	0.041	0.098
[D]	Change in Capacity	286	191	286	191	286	191	286	477	191	286	191	286
[E]	100 * [C]/[D]	-0.0003	-0.0005	0.0003	0.0010	0.0031	0.0037	0.0063	0.0075	0.0094	0.0168	0.0215	0.0342

It is important to note that the capacity level at which incremental Zone J capacity has no impact on the loss of load expectation is not the level of capacity at which the NYCA loss of load expectation falls to zero. While incremental Zone J capacity above 113 percent of the target does not further reduce the NYCA loss of load expectation, the loss of load expectation for the NYCA is well above zero, around .063 days per year. The reason for this is the way the local capacity requirements are calculated. Recall from the discussion in Section II D3c above that the Zone J capacity requirement is determined by adding capacity to Zone J and subtracting it from Zones A, C and D, with no net change in NYCA capacity. At the capacity level at which there is no benefit to shifting additional capacity into Zone J, the NYCA has loss of load events that could be reduced through the availability of additional total capacity. The implication of the lack of reliability benefit to additional Zone J capacity relative to upstate capacity is that there is no congestion into Lower Hudson Valley or Zone J during these loss of load events so Zone J and upstate capacity are equally effective in avoiding load shedding. In these circumstances there would be value to additional capacity located in the NYCA, whether located in Zone J, K or upstate, as the additional capacity would serve to reduce the loss of load expectation.

Table 20
Long Island Ratio of the Change in LOLE to the Change in Capacity per 100 MW

		Percentage of Target Capacity Requirement											
		118%	**115%**	**113%**	**110%**	**108%**	**105%**	**103%**	**100%**	**98%**	**95%**	**93%**	**90%**
[A]	Capacity	6,455	6,291	6,182	6,017	5,908	5,744	5,635	5,470	5,361	5,197	5,087	4,923
[B]	LOLE	0.056	0.057	0.059	0.064	0.068	0.076	0.083	0.100	0.114	0.147	0.177	0.251
[C]	Change in LOLE	0.001	0.002	0.005	0.004	0.008	0.007	0.017	0.031	0.014	0.033	0.03	0.074
[D]	Change in Capacity	164	109	164	109	164	109	164	274	109	164	109	164
[E]	100 * [C]/[D]	0.0006	0.0018	0.0030	0.0037	0.0049	0.0064	0.0104	0.0113	0.0128	0.0201	0.0274	0.0451

The loss of load probabilities calculated for Long Island capacity have the same feature we discussed above with respect to Zone J, there is still value to incremental capacity at the point at which there is no differential value to capacity located in Zone K relative to upstate.

Table 21
Lower Hudson Valley Ratio of the Change in LOLE to the Change in Capacity per 100 MW

		Percentage of Target Capacity Requirement											
		118%	**115%**	**113%**	**110%**	**108%**	**105%**	**103%**	**100%**	**98%**	**95%**	**93%**	**90%**
[A]	Capacity	17,586	17,138	16,840	16,393	16,095	15,648	15,350	14,903	14,605	14,158	13,860	13,413
[B]	LOLE	0.090	0.078	0.074	0.072	0.072	0.074	0.080	0.100	0.125	0.195	0.277	0.475
[C]	Change in LOLE	-0.012	-0.004	-0.002	0	0.002	0.006	0.02	0.045	0.025	0.07	0.082	0.198
[D]	Change in Capacity	447	298	447	298	447	298	447	745	298	447	298	447
[E]	100 * [C]/[D]	-0.0027	-0.0013	-0.0004	0.0000	0.0004	0.0020	0.0045	0.0060	0.0084	0.0157	0.0275	0.0443

As is the case for capacity in Zones J and K, Table 21 shows the value of capacity located in Lower Hudson valley relative to capacity in upstate New York.

iv. Estimated Incremental Value of Capacity

The monthly reference price of capacity can be combined with the information on the change in reliability associated with incremental capacity at the target level of capacity to calculate the implied monthly value of incremental reliability at the target level of capacity, i.e. the monthly value of avoiding a load shedding event; these values are reported in Table 22. Because the loss of load expectation is calibrated in terms of loss of load events per year, and the capacity price data used for the calculation is the monthly capacity price, the figures reported in the table correspond to the monthly value of avoiding a load shedding event over the year.[114]

The derivation of the implied cost of load shedding for the NYCA based on the reference price of capacity and the reduction in loss of load probability from incremental capacity at the target level as shown in Table 22. The calculation of the implied cost of load shedding based on the loss of load probabilities for Zones J, K and a potential Lower Hudson Valley Zone is complicated by the way these loss of load probabilities have been calculated. As discussed above, the change in loss of load expectation for capacity in Zones J and K is calculated relative to capacity in upstate New York (NYCA).

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114 Since the loss of load expectation is expressed in terms of outages per year, it might be more intuitive to express the costs as the annual value of avoiding a load shedding event over the year. Since the ICAP prices and reference prices are typically reported as monthly values and the demand curve is monthly, however, we thought it would be more confusing, not less, to convert prices and costs form monthly to annual and back to monthly, so we have reported these values in terms of the monthly value of avoiding an annual load shedding event

We have therefore calculated the implied cost of load shedding based on the loss of load expectations for Zone J and Zone K capacity based on the difference between the Zone J or Zone K reference price, and the value of NYCA capacity. For this purpose we have used the price of NYCA capacity in the July 2012 spot auction, $1980 per megawatt. This approach yields the implied cost of load shedding consistent with the cost of capacity in these zones portrayed in Table 22. We have not attempted to calculate an implied cost of load shedding for Lower Hudson Valley because we do not have a reference price of capacity for Lower Hudson Valley to use in this calculation.

Table 22
Implied Monthly Cost of Load Shedding Event

	NYCA	Zone J	Zone K
Reference Price	$9,900	$20,940	$11,190
NYCA	N/A	$1,980	$1,980
Price Premium	N/A	$18,960	$9,210
100 * ΔLOLE / Δ Capacity	0.0031	0.0075	0.0113
Implied Cost of Load Shedding	$324,048,814	$251,378,000	$81,285,677

Notes:
1. "Reference Price" Row equivalent to UCAP Based Reference Points for Summer 2012 Capability Period.
2. "NYCA" Row is NYCA Spot Market Auction Price from July, 2012.

The implied outage costs derived for NYCA and Zone J capacity are fairly similar. The implied outage costs for Long Island capacity, however, is much lower than for NYCA or Zone J capacity. Since the loss of load events are not necessarily confined to the region in which the capacity is removed, this could reflect an inconsistency in the solution, suggesting that a higher local capacity requirement should be maintained for Long Island. However, in practice, the loss of load events associated with incremental changes in Zone K capacity may effectively be confined to Long Island and hence the level of the local reliability requirement could reflect a lower cost of outages in Zone K.

v. Projected Capacity Demand Curve

The value of incremental reliability derived in Table 22 can then be combined with the estimates of how the likelihood of a loss of load changes with more or less than the target level of capacity to calculate the total value of incremental capacity at various levels above and below the target level, as shown for the NYCA, Zone J and Zone K in Table 23.

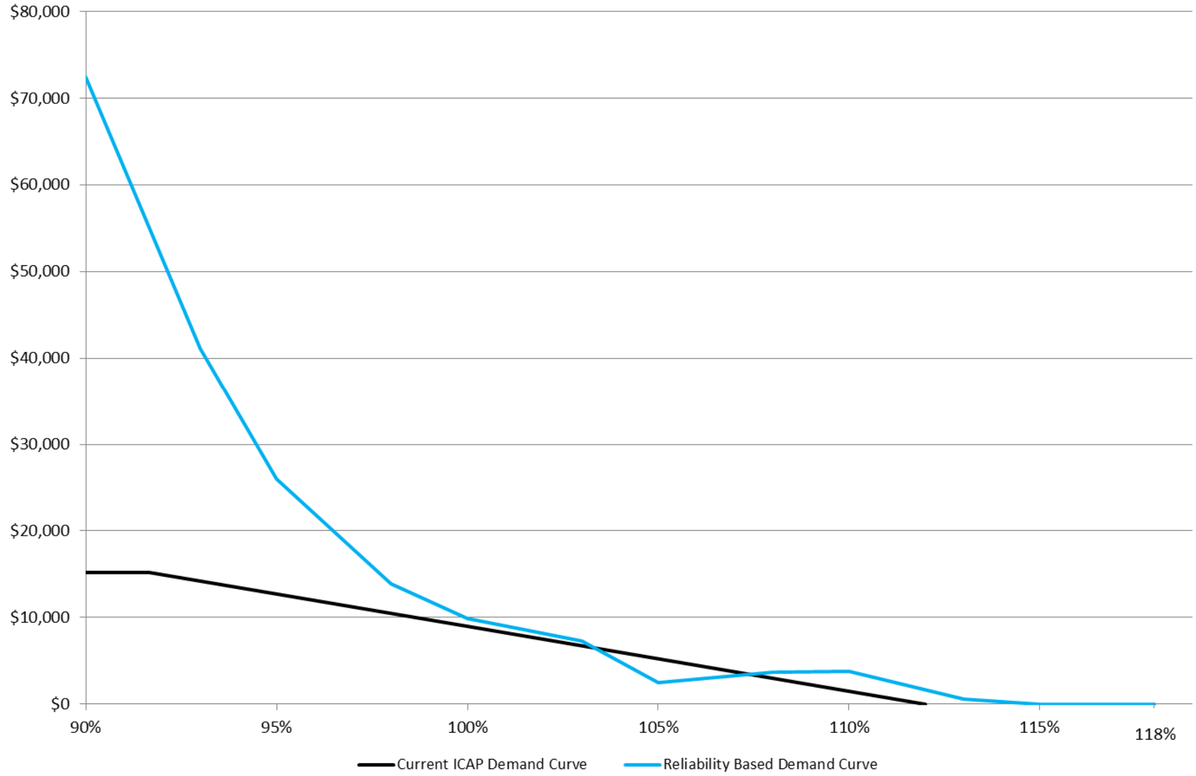
Table 23
Using NYCA Price Floor

Percentage of Requirement	New York City	Long Island
90%	$87,996	$38,635
93%	$55,969	$24,270
95%	$44,125	$18,326
98%	$25,682	$12,382
100%	$20,940	$11,190
103%	$17,779	$10,396
105%	$11,198	$7,181
108%	$9,882	$5,943
110%	$4,614	$4,952
113%	$2,858	$4,457
115%	$1,980	$3,466
118%	$1,980	$2,475

As noted above, the assumption that additional capacity in New York City (Zone J), Long Island (Zone K) and lower Hudson Valley (Zones G and H) is removed solely from Zones A, C and D, causes the reliability impact of additional capacity in New York City to go negative before the capacity margin reaches 118 percent of target as shown in Table 19. Capacity values in this range have been set to the NYCA price floor in Table 23.

Figure 24 portrays the current NYCA demand curve and the reliability-based NYCA demand curve based on the ICAP reference price. Three features of these demand curves are apparent from the figure. First, the reliability-based demand curve based on the ICAP reference price yields a demand curve that is fairly similar to the current demand curve over the range from 100 percent down to about 110 percent. Second, the reliability-based demand curve yields much higher prices than the current demand curve as capacity falls below the target level. Third, the value of incremental generating capacity falls to zero at a slightly higher level of surplus capacity than the current demand curve.

Figure 24
NYCA Capacity Demand Curves

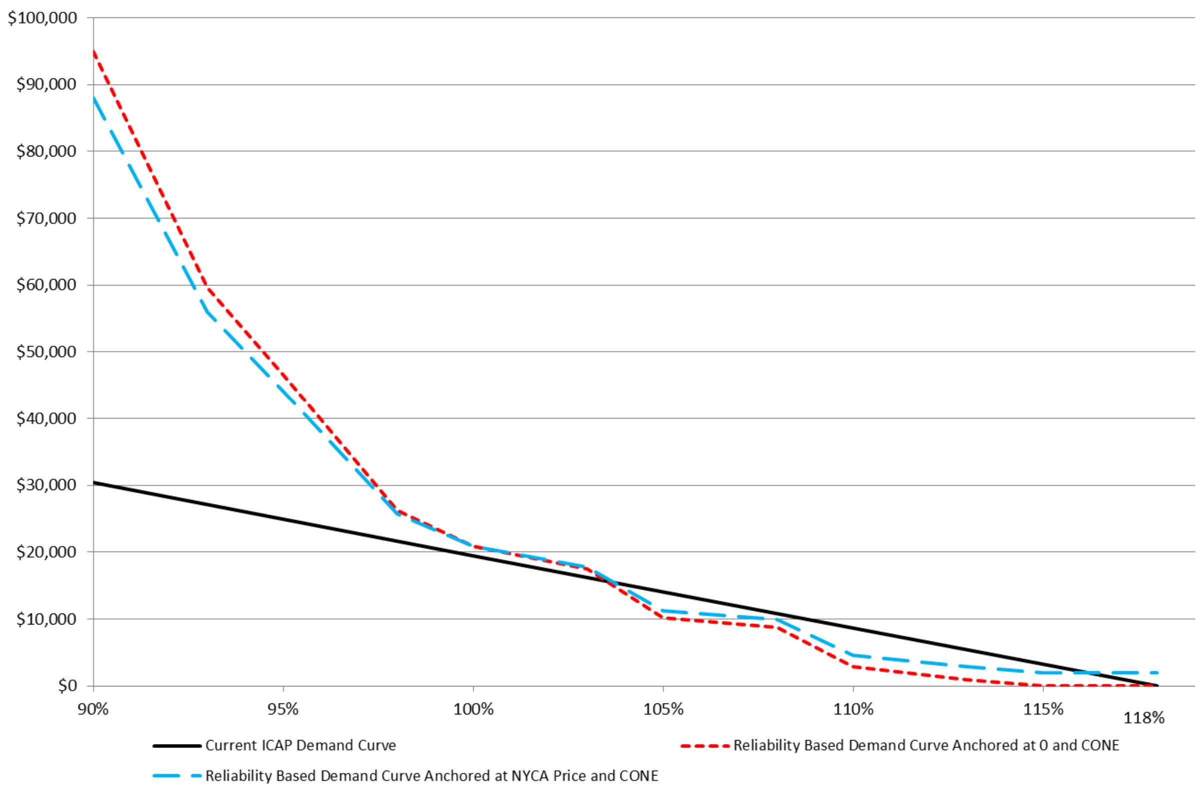


The demand curves portrayed in Table 23 for Zones J and K have the feature that the floor on the value of incremental capacity in Zones J and K is the NYCA spot price in the July 2012 auction, reflecting the level at which local capacity and upstate capacity have the same reliability value. Table 23 illustrates the fact that if the capacity market demand curve is intended to reflect the reliability value of incremental generation capacity within the various zonal markets, there would be a conceptual inconsistency between the way the local capacity requirements are determined and anchoring the lower bound of the demand curve at zero for the level of capacity at which the change in loss of load expectation is zero for additional local capacity. As observed above, the local capacity requirements for Zones J and K are currently determined by shifting capacity from J or K to upstate New York (Zones A, C and D), holding total NYCA capacity constant. The impact of increased Zone J capacity on the NYCA loss of load expectation calculated in this manner does not measure the reliability impact of increasing total NYCA capacity by adding capacity in Zone J, but just the change in reliability if the capacity is located in Zone J instead of Zones A, C and D.

This implies that a reliability value calculated for incremental generating capacity located in Zones J and K based on the loss of load probabilities in Table 19 and Table 20 would not measure the value of that capacity, but would instead measure the amount by which the reliability value of that local capacity exceeds the reliability value of capacity located in upstate New York. Hence, if the New York ISO were to base the shape and anchor points of the capacity market demand curves more explicitly on the reliability value of incremental generating capacity, this would have the implication that the point at which shifting incremental Zone J capacity to upstate New York has no impact on the loss of load expectation is not the capacity level at which Zone J capacity has zero value, i.e. at which the demand curve would intersect the x axis, but rather is the capacity level at which Zone J capacity would have the same value as NYCA capacity as shown in Table 23.

This distinction is illustrated in Figure 25 below. The black line portrays the current demand curve for New York City which reaches a zero value for capacity when capacity rises to 118 percent of the target level. The blue demand curve is based on the figures in Table 23, derived assuming that incremental Zone J capacity has the same value as NYCA capacity ($1980 based on the July 2012 spot auction price) when additional Zone J capacity, i.e. capacity shifted from upstate to Zone J, has no impact on the overall loss of load expectation. This curve is slightly steeper than the current curve for a range out to about 116 percent of the target and then is flatter.[115] For comparison, we have also included a demand curve based on the reliability value of incremental capacity, derived assuming that shifting additional capacity into Zone J has no impact on the overall loss of load expectation (the red line). This demand curve falls to zero when capacity reaches roughly 115 percent of the target, so is slightly steeper than the current demand curve for capacity in excess of the target.[116]

Figure 25
New York City



115 We recognize that taking account of the derivation of local capacity requirements in anchoring the lower end of local capacity demand curves based on the NYCA clearing price could be complex to accurately implement. In recognition of this complexity we do not recommend a particular resolution to this inconsistency. While methods based on iterating to an exact solution based on the results in each auction could be complex to implement, other more ad hoc methods of accounting for this inconsistency, such as anchoring the lower end based on the prior spot market auction price for the same season, would be straightforward to implement and might be found to produce very similar results. Rather than recommending a specific approach, we have pointed out the inconsistency and leave it for the New York ISO and its stakeholders to consider the best way to address that inconsistency.

116 The Tables deriving this line are included in Appendix A.

The difference between a capacity market demand curve with its lower bound set to the zero crossing point and a capacity market demand curve with its lower bound set equal to the NYCA capacity price is not very noticeable in Figure 25 in part because the price of NYCA capacity is currently very low relative to price of capacity in Zone J. Figure 26 adds a Zone J demand curve with the lower bound anchored at ½ of the current NYCA reference price and at the current NYCA reference price. Figure 26 illustrates two points. First, that the higher the price of NYCA capacity, the more difference it will make whether the lower bound of the capacity market demand curve is anchored at 0 or at the NYCA capacity price. Second, the smaller the surplus of Zone J capacity relative to the target, the less difference it will make how the lower bound of the capacity market demand curve is anchored.

Figure 26: New York City
(Price is $ per Megawatt-Month)

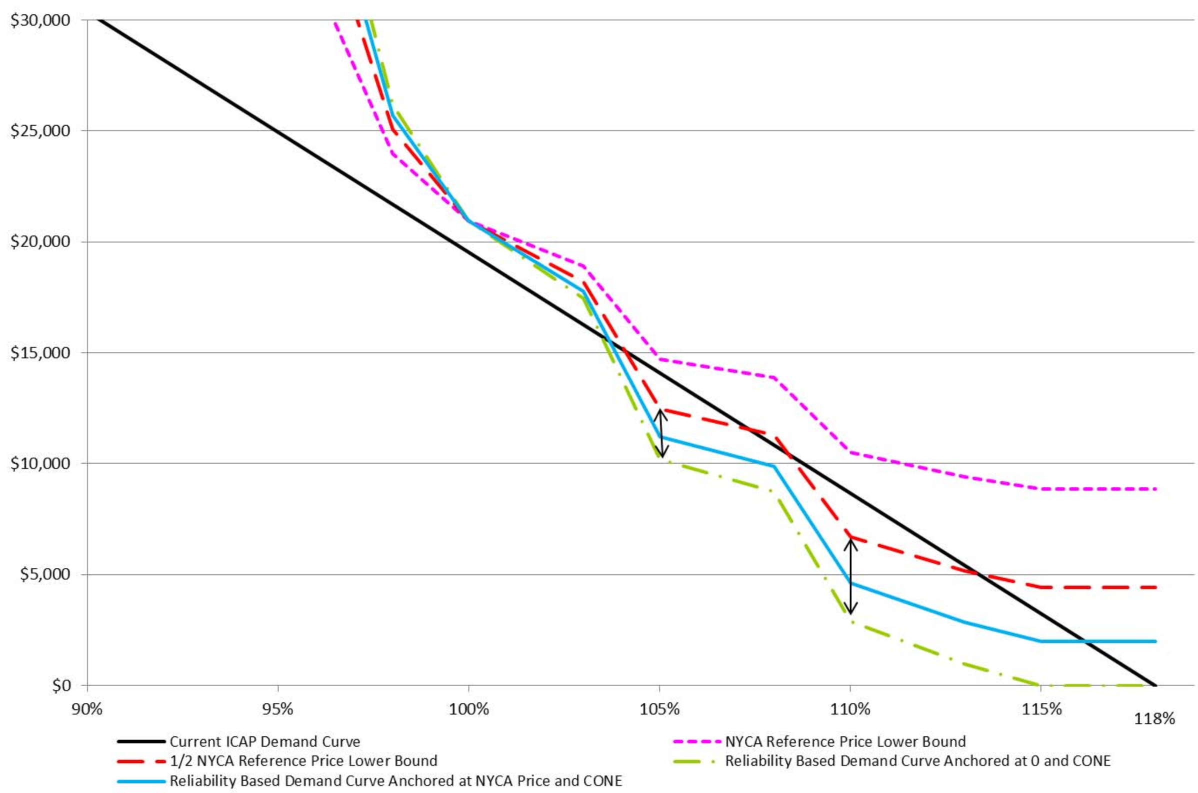
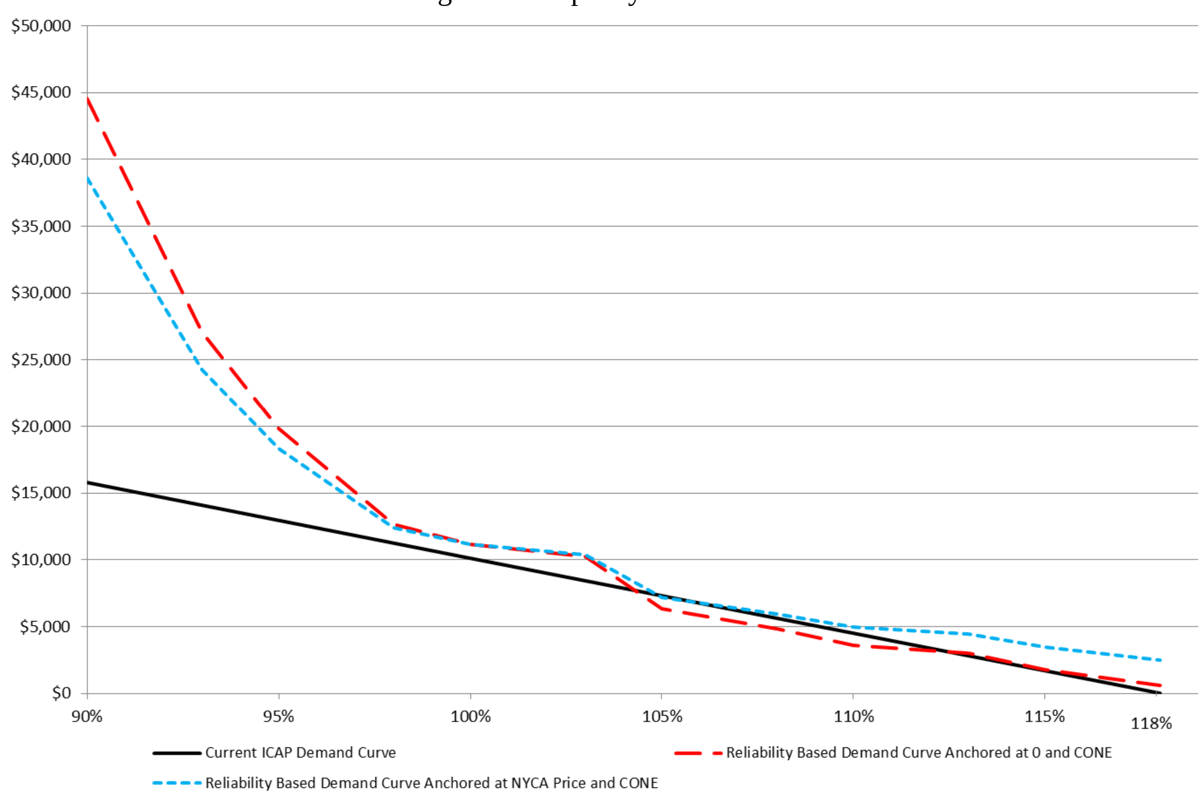


Figure 27 portrays similarly constructed demand curves for Long Island. The black line portrays the current demand curve for Zone K which reaches a zero value when capacity rises to 118 percent of the target level. The blue demand curve is based on the figures in Table 23, derived assuming that incremental Zone K capacity has the same value as NYCA capacity ($1980 based on the July 2012 spot auction price) when additional Zone K capacity, i.e. capacity shifted from upstate to Zone K, has no impact on the overall loss of load expectation. This curve is very similar to the current demand curve for a range from about 98 percent of the target capacity out to about 110 percent of the target and then is flatter than the current demand curve, in part reflecting that it measures the premium of Zone K capacity relative to NYCA capacity. A reliability-based demand curve anchored in the same manner as the current demand curve would also be very similar to the current demand curve from about 98 percent of the target level out to around 117 percent of the target but extends out slightly further than the current demand curve. Because we did not simulate capacity margins in excess of 118 percent we have not determined the exact capacity level at which the Long Island demand curve would reach its lower bound.

Figure 27
Long Island Capacity Demand Curves



Figures 24 to 27 show that for the capacity levels above the target level, the reliability-based demand curves are roughly, but not exactly, linear. While the reliability based demand curves portrayed in Figures 24, 25, 26 and 27 are not linear, in our view they do not differ materially from a roughly linear demand curve, particularly if account is taken of the limited number of data points used to define the curves.

Hence, a simplified approach that would be roughly accurate would be to derive linear demand curves for the region from the target level out to the zero crossing point or however the lower bound is defined. For the NYCA region, the loss of load expectation data suggest that the lower bound should be shifted out from 112 percent to around 115 percent, producing a slightly flatter demand curve that the current demand curve. The data similarly suggest that the lower bound should be shifted in from 118 percent to 115 percent for New York City, possibly producing a slightly steeper demand curve, depending on the lower bound. The Zone K data indicate that the lower bound would be a level of capacity in excess of 118 percent, which would require a few more GE-MARS runs to define. Finally the data suggest a lower Hudson Valley lower bound of 112 percent.

Running GE-MARS evaluations for additional capacity levels might fill in the shape of the reliability capacity tradeoff for capacity levels in excess of the target but would not eliminate the fundamental non-convexity in loss of load expectation calculations.

For capacity levels less than the target, the reliability-based demand curve is clearly significantly steeper than the current demand curve and has discontinuities in the slope. Three approaches could be taken to defining a reliability-based demand curve for this region. One approach would be to smooth out the curve and reduce the extent to which there are breakpoints by estimating loss of load probabilities for additional capacity levels and filling in additional points on the curve, which would tend to smooth out the changes in slope. This would lead to a more complex implementation because there would be more segments with distinct slopes to be used in calculating the clearing price, but only when there was a shortfall of capacity relative to the target.

Another approach would be to simplify the curve by eliminating some of the breakpoints, which would tend to produce larger changes in slope, i.e. bigger discontinuities but would be simpler to implement. There is a potential for large discontinuities in the slope to increase the profitability of economic withholding (or contracting for uneconomic capacity but that is less likely to be relevant in this range of capacity shortfalls and high capacity prices), which would be increased by reducing the number of segments.

The third approach would be to retain something similar to the number of breakpoints used in the illustrative calculations.

The steeper the slope of the demand curve, the greater the incentive for economic withholding of capacity in order to drive up the clearing price. However, a demand curve that significantly understates the value of incremental capacity would provide much too little incentive for new generation capacity to enter or for the development of demand response. This would be an undesirable outcome, particularly if the shortfall in capacity has arisen because the estimated CONE understates the actual cost of new capacity. Moreover, the capacity zone in which there is the greatest potential for the exercise of market power, Zone J, is subject to extensive market power mitigation mechanisms.

d. Conclusions

We recommend that the shape of the capacity market demand curve be based on a reasonable representation of the reliability value of incremental generating capacity. Given the anchor points at Net

CONE and zero, the current demand curves are roughly consistent with such a reliability-based demand curve for capacity levels in excess of the target, although the Long Island and NYCA demand curves should apparently be slightly flatter and the New York City demand curve slightly steeper.

It however, as discussed above, appears to us that there is an inconsistency in how the local capacity requirements are determined, and how the local demand curves are anchored from the perspective of a reliability value based demand curve. We do not recommend a particular way to resolve these inconsistencies but if a reliability based demand curve is implemented, we recommend that they be considered and addressed in the development of the new capacity zone or zones.

E. Review of Methodology for Creating New Capacity Market Zones

1. Overview

The New York ISO and the New York Transmission Owners filed their proposed methodology for creating new capacity zones in Docket ER04-449 on January 4, 2011. The independent Market Monitor, David Patton, questioned both the thresholds that would be applied to identify the need for a new capacity zone and the additional considerations.[117] The Commission rejected a number of elements of this proposed methodology in its September 8, 2011 Order.[118]

In its subsequent compliance filing, which was accepted by the Commission, the NYISO proposed to study creating new capacity market zones every three years in conjunction with the reset of the demand curve.[119] It would be convenient from an administrative standpoint to determine the shape of all of the

117 New York Independent System Operator. Motion to Intervene and Comments of the New York ISO's Market Monitoring Unit, in Docket ER04-449. Submitted January 25, 2011.

118 New York Independent System Operator, 136 FERC ¶ 61,165. Issued September 8, 2011.

119 New York Independent System Operator, Inc. Compliance Filing, in Dockets ER04-449 and ER12-360. Submitted November 7, 2011, accepted 140 FERC ¶ 61,160, August 20, 2012.

capacity market demand curves in a single process. A single process for defining demand curves for new and existing zones would also help avoid inconsistencies that could arise if the demand curve for a new zone or zones were determined in a separate process from the other demand curves. Carrying out this process every three years rather than every year would be desirable from the standpoint of conserving New York ISO resources and reducing the burden of these proceedings on market participants and other stakeholders.[120]

Our understanding of the intent of the design that the New York ISO included in its compliance filing is that every three years the New York ISO would study whether on-going changes in the market warranted the definition of new capacity market zones, and if so, would establish demand curves for those new zones. The demand curves for the new capacity zones would be determined concurrently with the demand curves for existing zones. Once the new capacity zone and demand curves were accepted by the Commission and effective, they would be modeled in all subsequent capacity market auctions. It is our understanding that once created, the new capacity market zones would always be modeled and enforced in subsequent capacity market auctions. Hence, constraints defining the new zones might or might not bind from auction to auction but the new zones would be modeled in the spot auctions regardless of whether the constraints were expected to bind.

It is important that new capacity market zones be modeled and enforced in all future auctions. An alternative design in which the New York ISO would determine every three years whether to enforce existing zones in future auctions would invite circumstances in which zones are not enforced but the exit of generation would create reliability problems, requiring out-of-market contracts to keep generation in

120 A number of market participants and stakeholders expressed a desire to reduce the amount of resources devoted to administration of the capacity market in the July 31, 2012 capacity market working group meeting at which our initial observations were presented. Moving to an annual demand curve reset process would be a large step in the wrong direction from this perspective.

operation. This has happened repeatedly in the ISO New England FCM capacity market design[121] and the New York ISO should avoid a design that invites these kinds of outcomes. Instead, once created, capacity market zones should be modeled and enforced in every spot auction and either bind or not.

The approach we recommend is the same way Zone K has been modeled in recent years, the Zone K local requirement has always been modeled in the spot auction, even though Zone K capacity has often cleared at the same price as NYCA capacity. Bids and offers to buy and sell capacity in the voluntary forward strip and monthly auctions conducted by the New York ISO would apply to capacity in specific zones and might or might not clear at the same prices across zones.

However, while we recommend that zones continue to be modeled from year to year regardless of whether a particular zone is expected to bind in a particular year, we do not intended this recommendation to foreclose a re-evaluation of the capacity market zones following a major change in the New York ISO administered transmission network, with this evaluation possibly leading to the combination or reconfiguration of some prior capacity market zones.

Moreover, the evaluation of new capacity market zones should be forward looking, identifying new capacity market zones that reasonably could bind in an auction during the evaluation period. It should not take the form of a backward looking evaluation that only identifies the need for a new capacity market zone after it should have bound in an auction. This forward looking evaluation of the potential need for new capacity market zones could be guided by generation interconnection studies, by the results of deliverability tests in the generation interconnection queue,[122] and by the results of the New York ISO's biennial Reliability Needs Assessment.

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121 This is discussed in Section IIIC below.

122 A finding that a generation could be dispatched to its upper limit without creating overloads yet is not found to be deliverable suggests the likely need to define additional zones.

The current design in which some upstate capacity and demand response is deemed deliverable, either as a result of grandfathering or other rules, while new capacity is deemed not deliverable unless it is able to purchase CRIS rights, or builds transmission capacity that is not needed to meet load west of Central East, is unsatisfactory from both a market and reliability standpoint. It is unsatisfactory from a market standpoint because it undermines competitive entry. For example, under the current zonal design, a new low cost generator located at the same location as an existing generator in upstate New York would be deemed undeliverable and unable to compete with the incumbent generator, no matter how high the offer prices of the incumbent generator in the capacity market. This limitation of the current design has likely not had much impact on capacity prices in practice because of the surplus of grandfathered ICAP capacity and other existing capacity deemed to be deliverable.

The current design is unsatisfactory from a reliability standpoint because grandfathered upstate generation that clears in the capacity market auction is not necessarily able to meet New York power demand under high load conditions. While the process for determining the Zone J and K local reliability requirements will identify shortages of capacity East of Central East or South of Leeds-Pleasant Valley once capacity in these regions has shut down, and will compensate for the exit with an increase in the Zone J and K local capacity requirements, it will do so with a one year lag. Given the surplus of grandfathered upstate capacity, including imports, there is a potential each year for capacity located in zones F, G, H, and I that was assumed to be in operation in the determination of the local capacity requirements to exit because capacity market prices are inadequate to support its continued operation.

This reliability problem contributes to an additional market problem. At current upstate capacity price levels there is a potential for inefficient outcomes in which generating capacity in Zones F, G, H, or I with relatively low going-forward costs shuts down because upstate capacity prices are materially less than the generator’s going-forward costs. This inefficiency occurs because through the operation of the local capacity requirement this capacity could be replaced with new capacity in Zones J or K having costs several times higher.

The events over the summer and fall of 2012 illustrate the potential for the current zonal capacity market design to send inappropriate price signals for the entry and exit of capacity. The Zone J LCR was derived based on an assumption that there would be roughly 5168 megawatts of ICAP in Zones G, H and I.

Based on this assumption, the Zone J capacity price cleared at around 50% of the Zone J reference price during the Summer of 2012, suggesting a substantial surplus of capacity in the Zone G, H, I, J region.

In fact, however, only 4737.2 megawatts of Zone G, H, I ICAP (4462.4 megawatts of UCAP) cleared in the August 2012 auction, so the price signal sent by that auction should have reflected a relatively tight capacity supply in the Zone G, H, I, J region. Moreover, the shutdown of the Danskammer units and the reduced capacity of Bowline 2 will result in a substantial increase in the Zone J LCR and capacity price in 2013. These capacity needs could also be met with capacity located in Zones G, H or I, but capacity located in Zones G, H and will not receive the appropriate price signal under the current design
The actual determination of whether a new zone should be created and the boundaries of the new zone will of course need to be made before the process of resetting the demand curves begins so that any new zones can be included in the reset study. This is the approach that we understand has been provided for in the New York ISO's recently accepted compliance filing as noted above.

With regard to the criteria for assessing the need for a new capacity market zone, one indication of the need for the creation of a new zone would be constraints that are binding during loss of load events in the studies determining local capacity requirements that are not reflected in existing zonal boundaries.[123]

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123 It is our understanding that this is consistently the case under the current design in which the UPNY-SENY limit has been binding during loss of load events in recent local capacity requirement evaluations.

Another indication would be that interconnection studies for new generation within a particular zone find that capacity would not be deliverable into other load zones because of constraints generally corresponding to those enforced in the GE-MARs study used to define local capacity zones (i.e. constraints on the transfer of power between load zones rather than out of a generation pocket within a zone).[124] It is also possible that the forward looking Reliability Needs Assessment analyses (discussed in Section V) would identify developing constraints warranting the modeling of additional capacity market zones on a prospective basis.

The New York process for making this determination in the future, as accepted by FERC, will apply a single criterion to determine whether a new capacity zone is created. This criterion will require determination of whether there are any “Highway” constraints that bind under the deliverability test methodology applied in the interconnection process. If such a binding constraint is identified, the creation of a new zone is triggered. The first of these studies has started. Because this initial study has yet to be completed, this report does not provide any assessment of how the methodology is applied or whether the results are consistent with the outcomes we have recommended.

These annual or biennial processes should signal the need for the creation of a new zone before it becomes essential. If the New York ISO is aggressive in creating new zones in this three year cycle as soon as the need for them begins to emerge in the annual processes, the New York ISO and its market participants should find that the three year cycle of zone creation is workable in identifying the need for new capacity zones before they would bind in an auction or impact the deliverability of new capacity. We believe that such a periodic forward looking evaluation of the need for new capacity market zones

124 It is also our understanding that the UPNY SENY interface or corresponding transmission line limits have been binding in interconnection studies for upstate generation for a number of years.

conducted on a three year basis could be consistent with the approach recommended by the Independent Market Monitor.[125]

Some past discussion of timing issues have overlooked the relationship between capacity region definitions, the determination of local capacity requirements, and the nested relationship between NYCA and Zones J and K. Rather than inadequate capacity within a subregion of the NYCA necessarily giving rise to a reliability problem, in many circumstances this would result in a higher local capacity requirement for Zone J and or K. Since capacity in Zone J is likely to be much more expensive than capacity located in other regions within the NYCA, this would tend to raise overall capacity market costs, but the loss of load expectation would generally not be impacted.[126]

A concern has been expressed by some stakeholders that the creation of additional capacity market zones could raise capacity prices even if there were no binding transmission constraints. This possibility of higher capacity prices in the absence of binding constraints was suggested to arise from the operation of the capacity market demand curve.

If the capacity market demand curves for capacity zones within NYCA are defined to reflect the reliability value of incremental capacity as we have recommended, then these zonal capacity prices will exceed the NYCA capacity price only when constraints are binding in the models used to establish the local reliability requirements and define the capacity demand curve. Furthermore, because of the way these models are set up, the circumstances that produce binding constraints in these models would also produce congestion in the real-time market and in deliverability tests. If capacity market demand curves

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125 David B Patton, Pallas LeeVanSchaick, Jie Chen, *2011 State of the Market Report For the New York ISO Markets*. April 2012, p. 37.

126 For example, if the growth of load in Zones G, H, and I or the exit of generating capacity located in Zones G, H, or I caused the UPNY-SENY transfer limit between Zones E and F and G, H, and I to bind during loss of load hours within the GE-MARS runs used to determine the local capacity requirement, this would result in an increase in the Zone J local capacity requirement to reduce the loss of load expectation to the target level. Hence, failure to establish a new Lower Hudson Valley zone would not necessarily impact reliability but it would raise consumer costs if new Zone J generating capacity were more expensive than new generating capacity located in Zones G, H or I.

were not defined to reflect the reliability value of incremental capacity, but instead were flatter than warranted by the reliability value of incremental capacity, then it is possible that the concerns regarding elevated capacity prices despite no binding constraints might be valid in some circumstances. This possibility is another reason not to define artificially flat demand curves for capacity, but is not a reason to not define additional load zones because they might not bind.

If capacity market demand curves are defined based on the reliability value of incremental capacity as we recommend, then the lower bound of a local capacity demand curve will be set by the capacity level at which shifting capacity into the zone from outside the zone (e.g. shifting capacity from upstate New York into a Lower Hudson Valley Zone) has no effect on the NYCA loss of load expectation. This condition will be satisfied when transmission into the Lower Hudson Valley Zone is not binding during any of the simulated loss of load events in the simulations used to establish local capacity requirements and that could be used to define local demand curves based on the reliability value of incremental generation. For levels of zonal capacity in excess of this lower bound level, there would be no binding constraints on transfers into the new capacity Zone during any simulated loss of load event and the price of capacity within the zone would be the same as the price of capacity outside the zone. In this situation there would be no price elevation as a result of enforcing the additional capacity zone.

If the capacity located with the local region that cleared in the auction was less than the amount corresponding to this lower bound on the demand curve, then the zonal capacity price would exceed the capacity price in the broader region, but there would be binding constraints. Given the way the demand curve would be constructed, this capacity level would be associated with binding transmission constraints into the load zone during loss of load events in the simulation used to define the demand curve. Moreover, because the simulations used to define local capacity requirements for the demand curve are run with overall NYCA capacity reduced to the target level by adding load in the upstate region, the actual transmission system would be even more constrained than in these simulations, because there would be additional excess capacity upstate on the real transmission system.

There will be differences in zonal capacity prices only when transmission constraints are binding into the new capacity zone during loss of load event hours. The loss of load event probabilities the New York ISO uses to define its local capacity requirements and that we recommend the New York ISO use in defining the slope of the capacity market demand curves are the NYCA loss of load probabilities, not the loss of load probabilities associated with individual load zones.

When a loss of load event occurs in GE-MARS, GE-MARS will both assign that loss of load event to the NYCA as a whole and assign the loss of load expectation to a particular load zone within the NYCA based on the supply and demand balance within the individual load zone during the loss of load event. This loss of load expectation will be assigned to a particular load zone based on the supply and demand balance within the individual zone, even if there are no constraints on delivery of power into that individual load zone.

When the New York ISO defines local capacity requirements today, it does not base that evaluation on the impact of adding capacity to a load zone on that individual zone's loss of load expectation but on the change in the NYCA loss of load expectation. If there is no binding transmission constraint between two load zones during a loss of load event in GE-MARS, then shifting capacity between them will have no impact on the NYCA loss of load probability, although it could impact the individual load zone loss of load expectations.

Thus, for example, shifting capacity from Zone A into Zone B might change the Zone A and Zone B loss of load expectations in GE-MARS, even if there were no transmission constraints between Zones A and B. However, shifting capacity from Zone A into Zone B would have no impact on the NYCA loss of load expectation unless there were some binding transmission constraint between A and B during these loss of load events.

We have used, and propose that the New York ISO use, this same conceptual approach to determine the reliability value of incremental capacity, by using GE-MARS to simulate the impact of shifting increasing amounts of capacity into a local zone from upstate New York (Zones A, C, and D). If this methodology is used, there will be no impact on NYCA loss of load expectation, and hence no reliability value to shifting incremental generating capacity into a local capacity zone (while holding NYCA capacity constant), unless there is some binding transmission constraint between the load zone or zones from which capacity is shifted and the load zone or load zones to which the capacity is shifted. If there were no such binding transmission constraints during the loss of load event hours, the shift in capacity would not change the NYCA loss of load expectation.

Hence when we worked with the New York ISO to calculate the impact of incremental generating capacity located in a hypothetical Lower Hudson valley zone on loss of load probabilities, we examined the impact of shifting capacity into Lower Hudson Valley from Zones A, C and D on the NYCA loss of load expectation. This loss of load expectation declined initially with increases in the amount of capacity in the lower Hudson valley zone, because the UPNY-SENY interface was binding in loss of load events. With this constraint binding during simulated loss of load events, having more capacity south of UPNY-SENY avoided some loss of load events.

As we shifted more and more capacity from upstate New York into the Lower Hudson Valley, however; we eventually reached a point at which shifting more capacity into the Lower Hudson Valley had no impact on the NYCA loss of load expectation, because so much capacity had been shifted south of the constraint, that the constraint no longer bound during the loss of load event hours.

If capacity zone definition were instead based on differences in the individual load zone loss of load expectations calculated by GE-MARS, this could lead to the situation that concerned a number of participants in the August 31, 2012 New York ISO stakeholder meeting, identification of capacity zones encompassing regions that were not in fact transmission constrained during loss of load events.

As explained above, however, such an examination of differences in individual load zone loss of load expectation calculations is not the way the New York ISO uses GE-MARS to set local capacity requirements today and is not the way we propose that the New York ISO use GE-MARS to define either new capacity market zones or reliability based demand curves for existing or new capacity zones.

2. Load Zones and Capacity Market Zones

With respect to the potential need for new capacity zones having boundaries that do not correspond to current New York ISO load zones there are three distinct issues: 1) the potential for generation pockets located within existing load zones; 2) the potential for load pockets located within existing load zones and 3) the potential for major transmission constraints to emerge with boundaries that do not correspond to load zone boundaries.

a. Generation Pockets

There is in principle a potential for the construction of new generation resources within a transmission constrained region such that the incremental generation could not be delivered to load outside that generation pocket (and there might be little or no load located within the generation pocket). Under current New York ISO deliverability rules, the previously existing generation within the pocket would be able to participate in the New York ISO capacity market while the portion of the new capacity that was deemed not "deliverable" as a consequence of being located within the generation pocket would not be able to participate in the capacity market, unless it built transmission capacity. If the new entrant were lower cost than the incumbent generation, the current design would allow the entrant to buy the CRIS rights from the incumbent and participate in the capacity market.

b. Load Pockets

There is a corresponding potential for inadequate generation to be located within a load pocket, such as some pockets inside New York City, in part because the cost of operating or constructing capacity within that load pocket is materially higher than elsewhere in the load zone and because the differential energy and ancillary service margin from locating inside the load pocket are inadequate to cover these higher costs. One way for the New York ISO to address such a situation would be to establish additional capacity zones for these load pockets. Alternatively, the New York ISO or a transmission owner could address the reliability issue through what would in effect be a RMR type contract to finance the construction of generation capacity (or possibly demand response) that would not be economic based on energy, ancillary service and capacity market revenues. Depending on the size of the load pocket and the number of generating resources located within it, the creation of a new capacity zone may or may not appear to be a reasonable way to address the reliability need.

Another approach would be to try to avoid the need to rely on either capacity market payments or RMR payments to provide such localized incentives but instead account for such situations in energy and ancillary service market prices, which would be consistent with the goal discussed in Section IIB of increasing the importance of energy and ancillary service market revenues in sustaining reliability.

c. Intra-Zonal Constraints

There is also a potential for major transmission constraint that separate the NYCA to fall within load zones rather than along load zone boundaries. This will inevitably be the case to some degree, but if the differences between the load zone boundaries and actual transmission constraints are small, such as minor amounts of generation located within Zone G geographically but electrically interconnected on the north side of Leeds-Pleasant Valley, it may be possible to address the differences through the deliverability requirement without creating new capacity zones or formally changing the capacity zone boundaries. This would have the consequence that some power consumers might be located in a geographic segment of a load zone for which the actual cost of the capacity needed to maintain reliability are lower than for the zone as a whole, but the power consumers located in this subregion pay the higher capacity market costs of the larger zone.

While it would be preferable to define capacity zone boundaries that accurately reflect the relevant transmission constraints that define the capacity zone, given the constraints of existing metering capability and the approximate nature of the GE-MARS transmission system modeling that underlies the locational capacity requirements, it may not be cost effective to adjust capacity market boundaries to account for minor differences between the load zone boundaries and the transmission constraints defining the capacity zone.

On the other hand, there is also the potential for major transmission constraints to develop within a load zone so that there are substantial amounts of generation and load on both sides of the constraints. If such a situation develops, it will have to be addressed by developing new capacity zones that reflect the actual transmission constraints and the required metering/measurement capability would need to be developed. The Independent Market Monitor’s discussion of the potential need for separate zones encompassing the

138 and 345kv transmission system in Zone J in his recent state of the market report is an example of such a potential situation.[127] Given the substantial market administration costs associated with implementing such capacity zones within existing load zones, it should be a goal of the New York ISO to utilize energy and ancillary service pricing to avoid the need to create new capacity zones that are smaller than existing load zones to the extent possible.

3. Deliverability Test for New Capacity Zones

Because the New York ISO's process for identifying and establishing new capacity zones is in the process of being applied for the first time, we have not attempted to analyze the details of the methodology, which will likely evolve as it is applied. The New York ISO's proposed criteria for the identification of a new zone, as described in the new Section 5.16.1 of the Services Tariff,[128] appears to provide a generally reasonable implementation of the zonal deliverability requirement. Any zonal process for defining "deliverability" will inevitably fail to accurately measure the locational value of capacity in some circumstances, but the New York ISO's approach does not appear to have any readily avoidable flaws.

A critical consideration is that the evaluation of the new zone must include all potential generation, both all existing generation and all generation in the generation interconnection queue with in service dates reasonably within the forward period covered by the evaluation,[129] To be clear, by all generation, we mean all generation, whether existing or in the queue, that seeks to participate in the capacity market, not limited to generation that has purchased CRIS rights or paid for deliverability upgrades. If methods

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127 David B Patton, Pallas LeeVanSchaick, Jie Chen, 2011 State of the Market Report For the New York ISO Markets. April 2012, p. 38.

128 See New York ISO, New York Independent System Operator, Inc. Compliance Filing, in Dockets ER04-449 and ER12-360 at p. 4-6. Submitted November 7, 2011.

129 If this evaluation is carried out every three years in conjunction with the demand curve reset, the forward period would have to be at least three years and presumably longer to allow time for the various studies.

proposed by the New York ISO for use in evaluating a new zone do not in practice account for all of this generation, then those methods need to be modified to do so.

We also intend that this evaluation be limited to capacity "with in service dates reasonably within the forward period covered by the evaluation." Hence, the evaluation would not include projects that are in the queue but are not far enough long in development to reasonably anticipate that they would come into service within the forward period covered by the evaluation. In addition, the evaluation would not include duplicative projects, as they would not all be reasonably expected to come into service within the forward period covered by the evaluation.

The evaluation should include capacity that might or might not be retired, and capacity that might or might not return to service, because it is important that capacity zones be defined that provide efficient price signals for these potential entry or exit decisions.

4. LCR Methodology

The methodology that has been used to define the local capacity requirements has the potential to produce anomalous outcomes. These anomalous outcomes are largely unavoidable given the current zonal boundaries and binding transmission limits. With implementation of one or more new zones east of Central East consideration should be given to how the local capacity requirements will be determined in the future so as to avoid these kinds of anomalous outcomes.

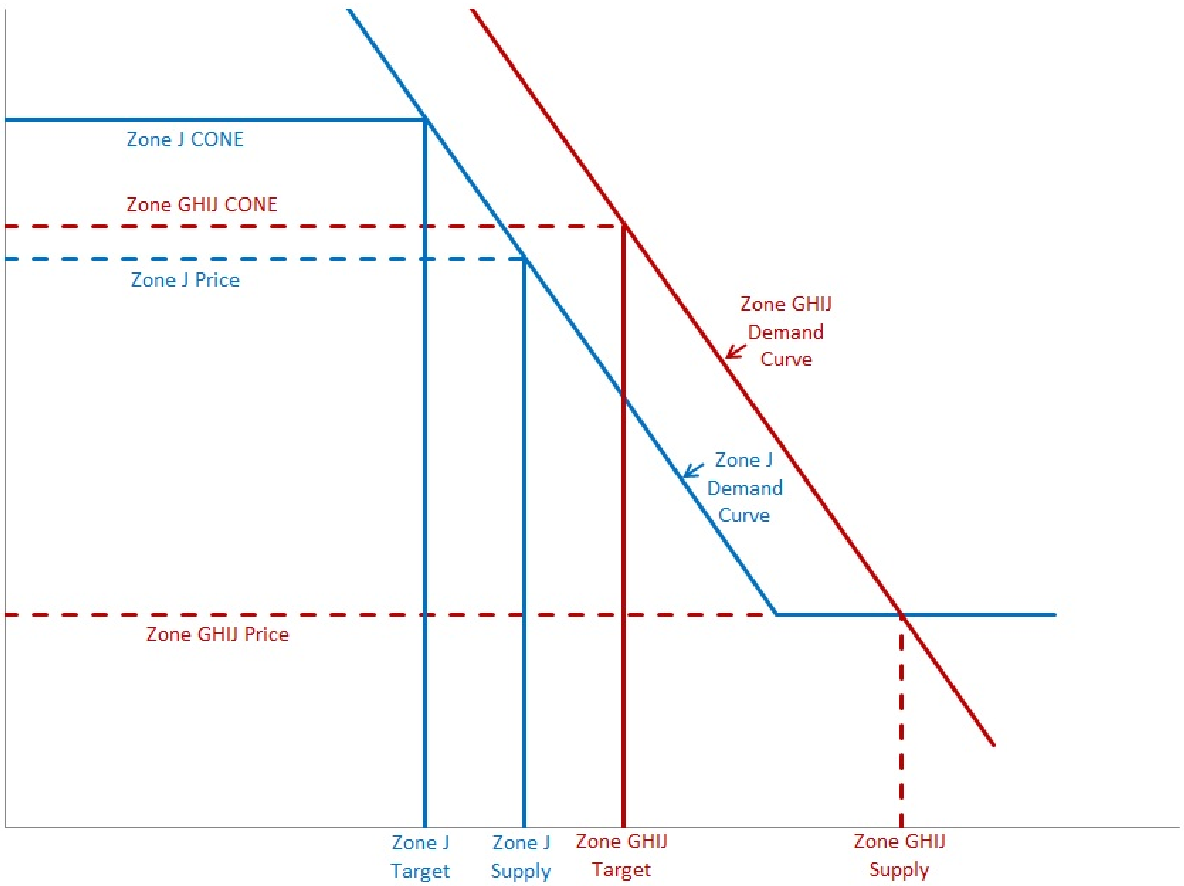
The source of the anomalies is that under the current methodology for determining the Zone J (and K) local capacity requirements, capacity is shifted from Zone J to upstate New York, Zones A, C and D, holding constant capacity in Zones G, H, and I. In practice, the constraint that is binding during loss of load hours in these models is not the constraint between Zones I and J, but the UPNY-SENY interface into G, H, I. Hence, if there is load growth in Zones G, H, or I, this will increase the Zone J local capacity requirement, because the only way to avoid the loss of load expectation would be to shift capacity from upstate to downstate. Similarly, the exit of capacity resource in Zone G, H, or I would increase the Zone J local capacity requirement, while the entry of a new capacity resource in Zone G, H, or I would reduce the Zone J capacity requirement. These kinds of outcomes in which Zone J and Zone K capacity are a proxy for Zone G, H, and I capacity and the Zone J and K demand curves potentially bounce around based on entry of exit of capacity in G, H, and I are unavoidable in the current capacity market design.

With the introduction of a new Zone or Zones east of Central East, however, the New York ISO will have more flexibility in how it determines the local capacity requirement and should consider approaches which base the Zone J local capacity requirements on the capacity that actually needs to be located in those zones, and uses the Zone J, G, H, and I local capacity requirement to specify the amount of capacity that needs to be in that Zone, and also account for Zone K capacity requirements in a way that insulates the local Zone K capacity requirement from changes in load or generation in Zones G, H, and I.

For example, if the New York ISO were to first determine the local capacity requirements for Zones J and K, this local capacity requirement would be determined given Zone G, H, and I load and capacity, so variations in load and generation in Zones G, H, and I would continue to shift the Zone J local demand curve in and out, changing the Zone J price as a result of changes in generation and load in Zones G, H, and I. This is illustrated in Figures 28 and 29.

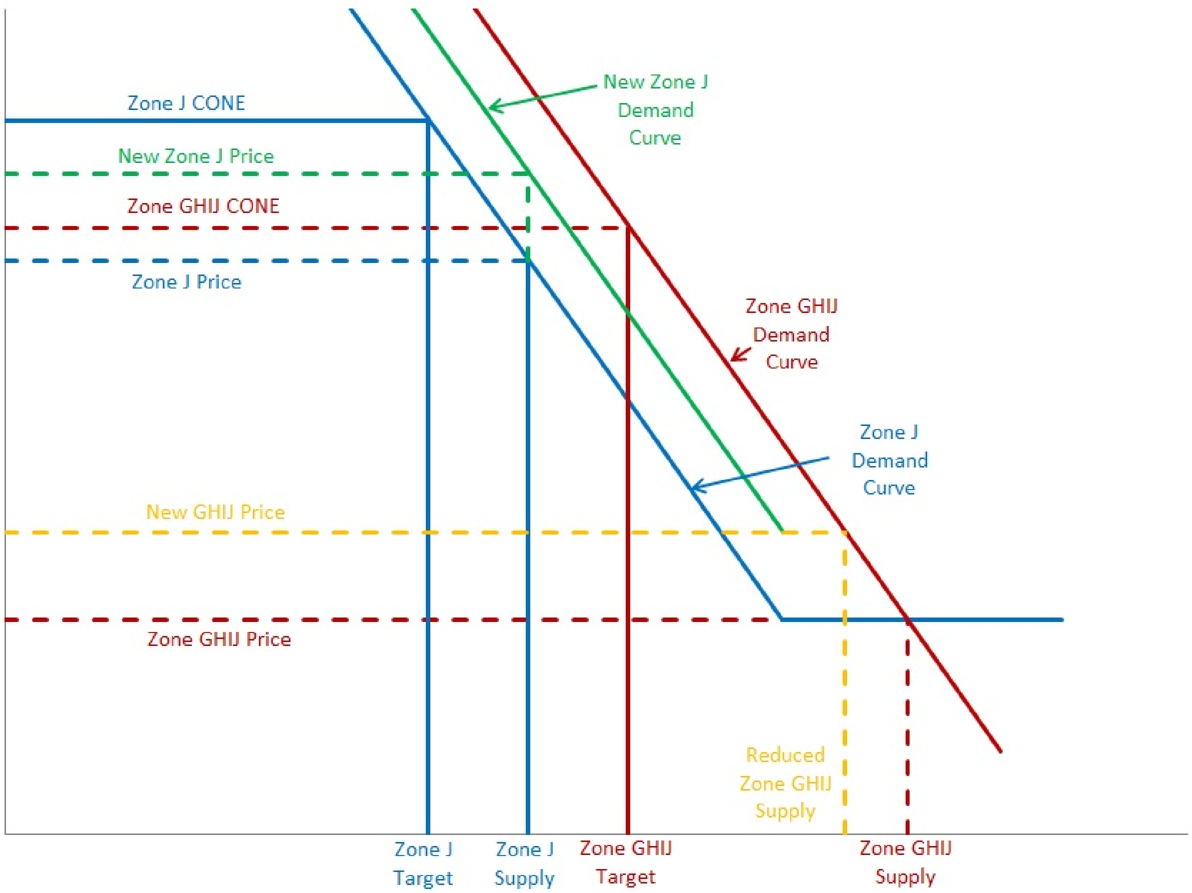
Figure 28 portrays the initial Zone J and Zone G, H, I, J demand curves, supply and prices. In this example we assume that the lower bound of the Zone J demand curve is the price of Zone G, H, I, J capacity, but the patterns would exist if the lower bound were the zero crossing point. Both Zone J and Zone G, H, I, J clear on their respective demand curves at quantities above the target, and with the Zone J price exceeding the Zone G, H, I, J price.

Figure 28



Then suppose that a capacity resource in Zone G exits the market in the next year. This would reduce the quantity of Zone G, H, I, J supply, raising the clearing price for the aggregate Zone G, H, I, J as shown in Figure 29. This is the outcome expected from a reduction in supply. However, if the local capacity requirement were determined the way it is today and the UPNY–SENY interface was binding in the loss of load evaluations, the reduction in Zone G supply would increase the Zone J local capacity requirement, even though the capacity lost was in Zone G. The increase in the Zone J local capacity requirement would shift out the Zone J demand curve and raise the Zone J clearing price as shown in Figure 29, even though there has been no change in anything affecting the Zone J supply demand balance. The exit of generation in Zone G would therefore not only send out a price signal for new capacity located within the aggregate G, H, I, and J zone, but would also send out a price signal for increased supply in Zone J. And conversely, if generation entered in Zone G, it would reduce the local capacity requirement and price of capacity in Zone J. As the New York ISO develops local capacity requirements for new capacity zones, it needs to evaluate the methodology used to set these requirements to make sure the requirements will consistently send appropriate price and capacity signals.

Figure 29

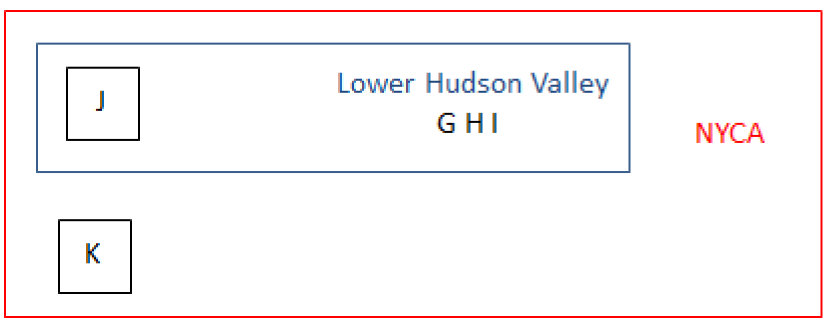


We do not recommend any specific changes in the determination of the local capacity requirement but recommend that when the New York ISO develops the procedures for determining the local capacity requirement, that it attempt to develop a process that would be less likely to lead to anomalous outcomes in Zones J and/or K when generation exits or enters Zones G, H, or I.

5. Nesting of New Capacity Zones

We have referred above to the potential for one or more new capacity zones to be defined that would include at least Zone J and would be located within the NYCA zone. This subsection discusses those nesting options in more detail. Figure 30 portrays the way we envision the definition of a new Lower Hudson Valley capacity zone with Zone J nested within it. In this design there would potentially be four distinct capacity market prices: Zone J, Zone K, Lower Hudson Valley and NYCA. Zone J and the Lower Hudson Valley zone could potentially clear at the same price if there was sufficient capacity in Zone J that the Zone J demand curve cleared at the same price as the Lower Hudson Valley demand curve. If the demand curve is based on the reliability value of incremental generation as we have suggested, this would only be the case if incremental Zone J capacity had no reliability value relative to Lower Hudson Valley capacity because the I-J interface was not binding during the loss of load event hours.

Figure 30
Lower Hudson Valley Nested within NYCA



Alternatively, it could be the case that Zone J and Lower Hudson Valley would clear at distinct capacity prices. If the lower bound of the Zone J demand curve were based on the reliability value of incremental generation as we have suggested, this would only be the case if shifting capacity from Lower Hudson Valley into Zone J reduced the NYCA loss of load expectation in the GE-MARS simulations, which would only be the case if transmission constraints were binding between Lower Hudson Valley and Zone J during the loss of load events simulated in GE-MARS.

A similar relationship would hold between the Lower Hudson Valley capacity zone and NYCA. The zones would clear at the same price if there was no incremental reliability value from shifting capacity into the Lower Hudson Valley from upstate. In fact we know that a Lower Hudson Valley zone and the NYCA capacity zone would not clear at the same price without a material increase in the amount of capacity located in the Lower Hudson Valley zone, since the UPNY-SENY interface has been binding during some loss of load event hours in GE-MARS simulations given the current capacity balance inside the UPNY-SENY interface.

As portrayed in Figure 30, Zone K would be nested within NYCA but would not be nested within the Lower Hudson Valley zone.[130] Zone K could therefore clear at the same price as NYCA if there was excess capacity located within Zone K relative to the maximum capacity on the Zone K demand curve. It could also clear at the same price as Lower Hudson Valley if the Lower Hudson Valley capacity exceeded the maximum capacity on the Lower Hudson Valley demand curve so that Lower Hudson Valley and Zone K both cleared at the NYCA capacity price.

Another alternative would be to include Zone K within the Lower Hudson Valley zone as shown in Figure 46. With such a design, Zone K could clear at a price above the Lower Hudson Valley Zone price or at the same price as capacity in the broader Lower Hudson Valley Zone.[131]

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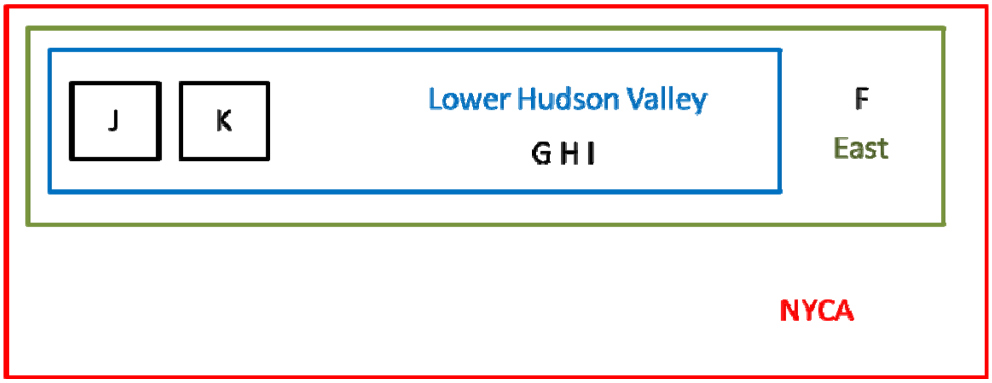
130 We assume for the purposes of this report, based on our conversations with the New York ISO, that Zone K would not be nested within a new Lower Hudson Valley zone have not undertaken or been involved in any modeling of Zone K relative to Lower Hudson Valley zone for this report.

131 If Zone K were nested within the Lower Hudson Valley zone for a range of capacity levels, there might need to be provision for Zone K capacity to clear at price below Zone K if the capacity surplus in Zone K was so large that the excess generation was bottled on Long Island.

Figure 46
Zones J and K Nested within Lower Hudson Valley



A third alternative would be to define the new zone to consist only of load Zones G, H and I, i.e. neither J nor K would be nested within the Lower Hudson Valley Zone as portrayed in Figure 47. Such a design could lead to anomalously high prices in the new Zone, however, if there were a shortage of capacity located in zones G, H and I relative to the target but a surplus of capacity in Zone J.

Figure 47
Zones J and K Outside of Lower Hudson Valley

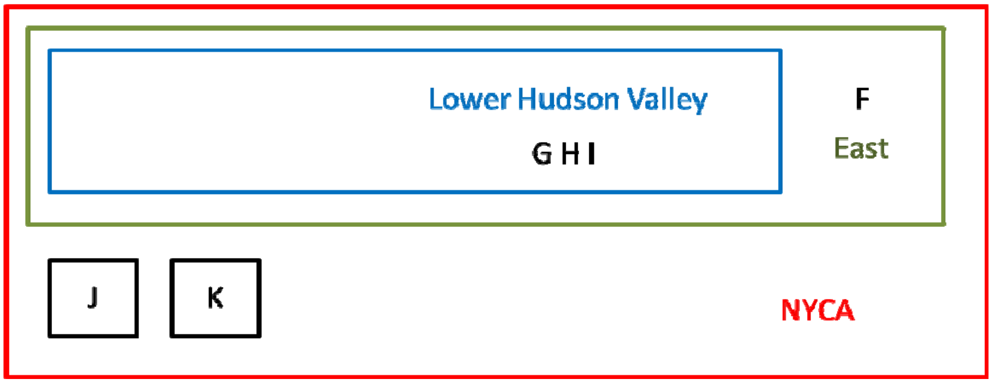
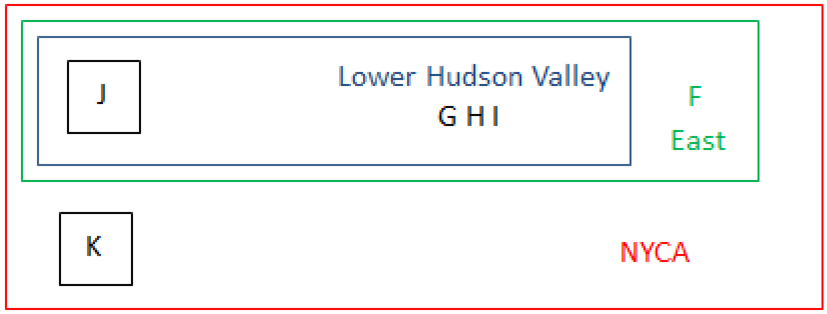


Figure 31, on the other hand, illustrates a capacity market design with two new capacity zones: a new Lower Hudson Valley zone consisting of Zones G, H, I, and J, and an East Zone consisting of Zones G, H, I, J, and F.[132] Hence, the Lower Hudson Valley Zone would be nested within the East Zone and could bind at the same price as the East Zone if the Lower Hudson Valley capacity exceeded the maximum

132 Such an East Zone could also be defined to include Zones F, G, H, I, J, and K.

capacity on the Lower Hudson Valley demand curve. We do not expect that to be the case, however, given the current capacity balance in UPNY-SENY.

Figure 31
Lower Hudson Valley Nested within East and NYCA



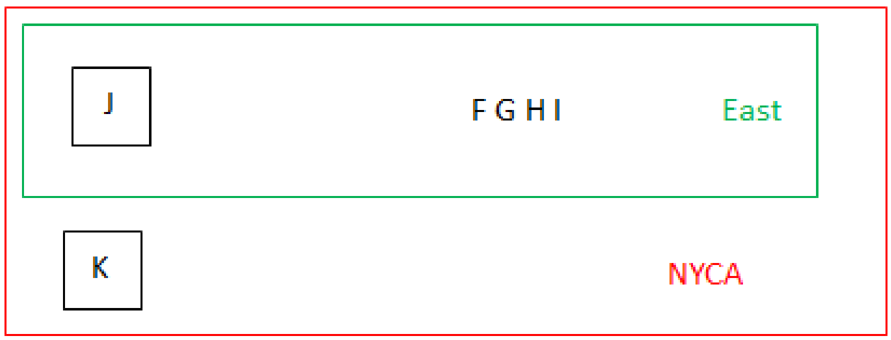
If the design portrayed in Figure 31 were implemented, the East Zone would not bind unless total east were binding during at least some loss of load events in the GE-MARS simulations. The East Zone would bind at a lower price than the Lower Hudson Valley zone if UPNY-SENY were binding in some loss of load event hours in the GE-MARS simulation, because Lower Hudson Valley capacity would have a higher reliability value at the margin than East capacity. Establishing an East Zone that is defined in this way could be helpful in modeling exports of capacity from New York to New England and making it more explicit that resources in Western New York cannot be assured of their ability to deliver capacity across Central East to New England.

More importantly, defining such an East Zone would help avoid outcomes in which Zone F capacity is sold in ISO New England capacity market because the NYCA capacity price is set by western New York generation at a level that is below the floor price or clearing price in ISO New England.

It is important to understand that the design portrayed in Figure 31 includes both an East Zone and a Lower Hudson Valley zone. If the UPNY-SENY interface was binding in some loss of load event hours in GE-MARS simulations at the current capacity level, then East and Lower Hudson Valley capacity could not clear at the same price, and capacity located in Zone F could not displace capacity located in

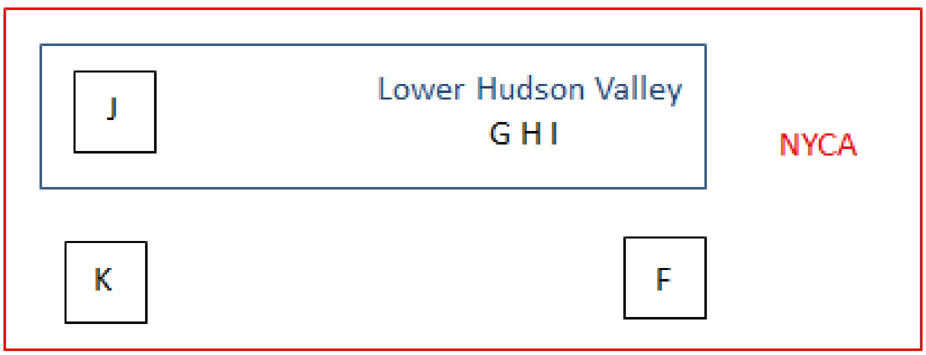
GHI. The Figure 31 design is quite different from a design in which there is a single new capacity zone consisting of Load Zones F, G, H, I, and J as shown in Figure 32. The design portrayed in Figure 32 does not include a Lower Hudson Valley zone so capacity in Zone F could displace capacity located in Lower Hudson Valley. This is not the design we propose precisely because such a design would not account for the UPNY-SENY interface, while the design portrayed in Figure 31 would account for that interface.

Figure 32
East only Design



Finally, another approach to defining multiple new capacity zones would be to define a new Lower Hudson Valley zone consisting of load Zones G, H, I, and J and to also define a separate Zone F capacity zone within NYCA, as portrayed in Figure 33. This design would have two limitations. First, it could result in artificially high capacity prices for Zone F because capacity located in Zones G, H, I, and J could not substitute for Zone F capacity in such a design. While it would be possible for Zone F capacity to at some point fall to the level at which there would be a need for such a Zone F local capacity requirement, it is our understating that is not the case at present. Second, the artificial restriction on the ability of capacity located in Zones G, H, and I to compete with capacity located in Zone F in such a design would tend to create market power where none should exist.

Figure 33
Separate Zone F Design



6. Conclusions

Because the New York ISO's process for identifying and implementing new capacity zones is in the process of being developed we have focused on what that process must accomplish to be effective, rather than attempting to assess how well the not yet implemented process will perform in achieving those objectives. First, it is acceptable for the process to be carried out every three years, but it is essential that the process be forward looking and identify and model constraints that could bind before they do. Second, the criteria for defining new zones should be consistent with any deliverability tests applied to new generation and must include all potential generation, both all existing generation and all generation in the generation interconnection queue with in service dates reasonably within the forward period covered by the evaluation that seeks to participate in the capacity market.

III. Review of PJM and New England Capacity Markets

In this section we review and evaluate the performance of the PJM RPM capacity market design and the New England FCM capacity market in eight respects.

- Ability to attract new capacity and maintain new capacity, including demand response and repowering;
- Ability to anticipate and respond in a timely manner to possible generator retirements, ;
- Ability to meet local capacity needs through appropriate deliverability requirements;
- Interrelationship between capacity market and energy and ancillary service markets
- Effectiveness in ensuring resources will be available for their commitment period;
- Effectiveness in incenting resource performance during the obligation period
- The relative role of administrative rules in determining market prices
- The rules to mitigate the exercise of market power

Each of these topics is discussed below.

A. Ability to Attract New Capacity and Maintain New Capacity, Including Demand Response and Repowering

The PJM and ISO New England capacity market designs are fairly similar to the New York ISO capacity market in terms of their ability to incent the construction and retention of generation capacity when it is needed to maintain reliability. Both markets make capacity payments for the continued operation of existing generation one year a time, as in the New York ISO design. In all three markets generation must compete with demand response to meet forecast peak load. In all three markets load serving entities are free to lock in their capacity costs by entering into long-term contracts with existing generators. The various minimum offer prices rules and delivery tests may at times create risks for load serving entities and generators entering into long-term capacity contracts for new generation resources.

The PJM and ISO New England capacity market designs have provisions that allow suppliers offering new capacity in the capacity market auction to lock in that clearing price over a multi-year period. In ISO New England new capacity has the option to lock in the auction capacity price over an additional four years.[133] There is no basis for assessing the performance of the ISO New England multi-year contracting option since all of ISO New England's capacity market auctions have cleared at the price floor since the first auction was cleared in 2008 covering the 2010-2011 operating year. The lack of use of the multi-year price lock in option by New England suppliers may therefore simply reflect their unwillingness to use the mechanism to lock in the floor price rather than any intrinsic flaw in the concept. Moreover, all new capacity built in New England under the FCM design has apparently been built under long-term contracts outside the capacity market design.

The PJM tariff contains provisions that allow new generation to lock in the initial capacity price for three years.[134] The PJM provision has also apparently been rarely if ever used by new generation entrants, but more due to its restricted applicability than lack of interest.[135]

While the idea of an entrant into the capacity market being able to lock in a capacity price is appealing, the implementation in PJM and ISO New England is not well related to this objective. If these provisions

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133 ISO New England, Transmission, Markets & Services Tariff, Sections III.13.1.1, 13.1.1.2.2.4 and III.13.7.1.6.

134 PJM, Open Access Transmission Tariff, Attachment DD Section 5.14 (c). PJM proposed to extend the term of this lock in to five years in its December 12, 2008 filing in Docket ER05-1410 and extended this duration to seven years in the settlement filed on February 9, 2009. Both extensions were rejected by FERC in its March 26, 2009 order (126 FERC ¶ 61,275) at 149 and 150. A more recent order provides for revisions to the lock in rules to be addressed in a stakeholder process, 135 FERC ¶ 61,022, April 12, 2011.

135 The Brattle Group's 2011 report indicated that of 30 companies that requested the lock in, only one entrant qualified. See Brattle Group, Second Performance Assessment of PJM's Reliability Pricing Model. August 26, 2011, p. 153.

are intended to, as FERC stated, "address the issue of lump investments in a small LDA,"[136](i.e. capacity zone) they are poorly designed for that purpose. In the entrant is concerned about the impact of its new capacity on clearing prices because it expects that its entry will depress clearing prices in the near term, it would want to lock in the capacity price before its entry or a long-run expected price absent entry, not lock in the depressed price in the first year its capacity clears in the market. Indeed, the price in the first year the new capacity clears in the market might be the lowest price of the next three or four years in such a small capacity zone, because the price would not reflect the gradual increase in capacity prices over time as demand grew.

If the objective of a new entrant is to lock in a price not unduly impacted by the impact of its entry on the capacity clearing price, a better way to accomplish these hedging goals would be through a contract with a capacity buyer, who could be willing to enter into a contract reflecting in part the pre-entry price.

Very little new capacity has been built in ISO New England under the FCM design and steadily declining quantities of new capacity have been offered in the FCA auctions. Table 34 shows the amount of new generation that has been offered and cleared in each of the FCA auctions. Apparently virtually none of the new capacity that entered in the FCA 2 auctions was financed based on capacity market prices, rather, most was built and financed based on a state RFP.[137] In particular, somewhere in the range of 994 -1108 megawatts of the 1157 of new generating resources that cleared in the auction as shown in Table 34 were funded by state contracts with Connecticut.[138] Around 10 percent of the capacity added in FCA 3 was also

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136 PJM, 126 FERC ¶ 61,275 at 149. Issued March 26, 2009.
137 See ISO New England Internal Market Monitor, 2011 Annual Markets Report. May 15, 2012, p. 67-68. See also Potomac Economics, 2011 ISO-NE Market Assessment, p. 114-117.
The ISO New England data reported in Table 34 does not include roughly 910 megawatts of new generation that was treated as existing for auction purposes because it was scheduled to come into service prior to the delivery period for FCA 1 as a result of the transition to the forward procurement design. See CRA International, Report on ISO New England Internal Market Monitoring Unit Review of the Forward Capacity Market Auction results and Design Elements. June 26, 2009, filed in docket ER09-1282-000 by New England Power Generators Association.
138 See ISO New England Market Monitoring Unit, Review of the Forward Capacity Market Auction results and Design Elements. June 5, 2009, p. 33, and ISO New England Market Monitoring Unit, 2011 Annual Markets Report. May 15, 2012, p. 68 Table 3-22.

built in response to a state RFP.[139] This state funded capacity apparently comprised almost all of the new net capacity added in FCA 3.[140] 1480 megawatts of the "new generating resources" listed in Table 34 as clearing in FCA 3 was the existing capacity of Brayton units 1-4 which were treated as "new" because of the substantial environmental upgrades required for the resources to remain in operation. These upgrades did not result in any new capacity entering the market, but avoided the exit of substantial existing capacity.[141] The lack of new capacity offers clearing in recent FCA auctions makes economic sense given the capacity surplus in New England, the expansion of demand response, and relatively low capacity market-clearing prices.

Table 34
ISO New England Forward Capacity Auction New Generating Resources

Auction	Operation Year	New Generating Resources Qualified for Auction (MW)	New Generating Resources Cleared for Auction (MW)
FCA 1	2010-2011	2353	40
FCA 2	2011-2012	3299	1157
FCA 3	2012-2013	2830	1670
FCA 4	2013-2014	947	144
FCA 5	2014-2015	669	42
FCA 6	2015-2016	133	79

Source:
1. FCA Flow Charts accessed from
http://www.osp.ne.com/markets/othrmkts_data/fcm/cal_results/index.html

139 See ISO New England Internal Market Monitor, 2011 Annual Markets Report. May 15, 2012, p. 67-68.
140 The ISO New England 2011 Annual Markets Report that 173 of the remaining 190 megawatts of new capacity were funded by the State of Connecticut. See ISO New England Market Monitoring Unit, 2011 Annual Markets Report. May 15, 2012, p. 68 Table 3-22.
141 New England Power Generators Association, Motion to Intervene and Protest of the New England Power Generators Association, in Docket ER10-787-000 at Affidavit of Robert Stoddard, p. 11, submitted March 23, 2010.

A substantial quantity of capacity has been built, or is committed to be built, in PJM under the its RPM capacity market design. Table 35 shows that around 14,500 megawatts of new capacity have cleared in the RPM auction for delivery years 2010/2011 through 2015/2016, along with roughly 3800 megawatts of capacity upgrades. The data in Table 35 are taken from PJM's report on the 2015/2016 RPM Base Residual Auction results (Table 8). These data indicate that more than 10 percent of the generating capacity in PJM's capacity market is new capacity.

Table 35
PJM Generation Capacity Resource Additions from 2007/2008 to 2015/2016

Delivery Year	New Capacity Units (ICAP MW)	Capacity from Reactivated Units (ICAP MW)	Uprates to Existing Capacity Resources (ICAP MW)
2007/2008	19	47	536
2008/2009	93.1	131	500.1
2009/2010	476.3		796
2010/2011	1027.7	170.7	577.8
2011/2012	2332.5	181	1062.8
2012/2013	1108		785.5
2013/2014	1320.2		417.3
2014/2015	1100.6	9	473.2
2015/2016	7658.9		548.1

Source: 2015/2016 RPM Base Residual Auction Results (http://pjm.com/markets-and-operations/rpm/~/media/markets-ops/rpm/rpm-auction-info/20120518-2015-16-base-residual-auction-report.ashx)

Similar figures for new capacity appear in the Independent Market Monitor's 2011 State of the Market Report, Table 4-5, with identical figures for new capacity in some years and slightly different figures in other years than those reported in Table 34.[142] Both the market monitor and the PJM data report ICAP capacity.

The Brattle Group 2011 report on the PJM RPM Market contains quite different, and lower, data for new capacity, based on Brattle Group calculations of outage-adjusted capacity or UCAP, using non-public

142 These minor differences may reflect differences in the way the temporary exit of Duquesne has been taken into account and the way other actual or projected changes in the PJM footprint were addressed in the data.

PJM bid data. Table 3 in the Brattle report identifies 4441 megawatts of capacity from new resources, whether internal to PJM or imported, as clearing for the first time in the auctions covering the 2010/2011 through 2014/2015 delivery years. Hence based on these data about 3.5 percent of the 127,029 megawatts of generating capacity that cleared in the 2014/2015 delivery year was capacity built or to be built under the RPM design over the 2010/11 through 2014/2015 period. The increase in demand response resources clearing the PJM RPM capacity market has been even larger than the increase in generation, with 13, 927 megawatts of demand response and energy efficiency clearing in the 2014/2015 auction compared to only 939 megawatts in the 2010/2011 Base Residual Auction.[143]

B. Ability to Anticipate and Respond in a Timely Manner to Possible Generator Retirements

The roughly three year forward procurement of capacity in the PJM and ISO New England capacity market designs has generally enabled these capacity markets to respond to the retirement of existing generation with new supply, avoiding the need for RMR procurement. This has been particularly evident in PJM where substantial capacity, generally coal, has retired or will retire as a result of environmental compliance costs. The retiring generation failed to clear in the RPM auction and has been replaced by lower cost resources, both new generation and demand response. Over 2000 megawatts of installed capacity was retired in 2010 and 2011 and successfully replaced within the RPM construct. Indeed, capacity prices remained below the Net CONE threshold and capacity in excess of target was procured in all of these regions.[144]

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143 There are a variety of minor inconsistencies in the data on new capacity in PJM reported at various times in various reports by PJM, the Independent Market Monitor for PJM, Monitoring Analytics, and the Brattle Group reports prepared for PJM. Some of these inconsistencies likely reflect minor differences due to reporting ICAP megawatts versus UCAP megawatts while the source of other inconsistencies is not clear. Since the exact amount of new capacity coming on line in PJM is not central to the focus of this report we have not attempted to resolve any of these inconsistencies.

144 See Monitoring Analytics, LLC, 2010 State of the Market Report for PJM. March 10, 2011, p. 35 Table 2-2 and Monitoring Analytics, LLC., 2011 State of the Market Report for PJM. March 15, 2012, p. 294 Table 11-15.

With the substantial and continuing level of retirements of coal fired generation in PJM driven by environmental regulations, however, there have been instances of generating resources that were needed to meet load in particular regions that have had to be kept in operation under RMR agreements.[145] It appears that these RMR agreements were generally needed to meet local reliability requirements, such as for voltage support, rather than to address a shortage of generating capacity within the region. An important observation about the effectiveness of the forward procurement process in identifying potential capacity retirements in advance of the retirement date is that a resource will not necessarily retire just because it does not clear in a particular year's forward capacity auction. Such a unit may remain in operation and offer capacity in subsequent auctions if capacity prices are expected to rise. Hence, the failure of a resource to clear in a forward auction does not necessarily signal a capacity retirement that would trigger transmission upgrades to address local reliability needs. However, if a resource does not clear in the forward capacity auction and no action is taken, then when it actually gives notice of retirement, there may be much less than three years available to make any necessary transmission upgrades or bring replacement generation into service.

This possibility has been manifested in PJM, where the need for the RMR contracts to keep retiring GenOn capacity in operation arose in part because GenOn did not immediately submit notices of its intent to retire these resources when they failed to clear in the relevant RPM auctions. PJM did not analyze the reliability impacts of these retirements until the 90 day notice of intent to retire the units was provided a year or two after the resources first failed to clear in a RPM auction.[146] This experience illustrates the fact that capacity market auctions will only identify deficiencies in aggregate capacity needs. Not only can resources that do not clear in forward capacity auctions remain in operation for some period of time before deciding to shutdown, resources that do clear in these forward capacity auctions can shut down even prior to the operating year by buying out of their forward commitment in subsequent auctions as

145 See for example, GenOn's filing in Docket ER12-1901.
146 See GenOn filing letter in docket ER12-1901, May 31, 2012 pp. 3-4.

discussed below in Section IIE. If a resource's retirement will trigger local reliability needs, those needs should be addressed by distinct forward local reliability contracts with such resources with a notice period sufficient to accommodate investment in alternatives means of maintaining reliability.

In New England, a number of generation retirements have led to RMR agreements to keep the units in operation past the forward time frame of the FCM auction. Most of these instances appear to have been a result of local capacity requirements that were either not enforced in the FCM auction or were set below the actual requirement. These instances are discussed in detail in Section IIIC below.

The overall effectiveness of the ISO New England FCM auction design in inducing the construction of new capacity to replace retiring resources has not been demonstrated because there has been no need to induce the construction of new capacity. All of the FCM auctions conducted to date have cleared at the price floor with a large surplus of capacity resources offered at the price floor in every auction.[147] This surplus of generating capacity has been a result of the substantial amounts of demand response offered and clearing in the FCM auctions, the declining demand in New England following the financial crisis, and a few thousand megawatts of new capacity that was built under contracts that are of out-of-market at current energy and capacity prices.

C. Ability to Meet Local Capacity Needs through Appropriate Deliverability Requirements

Both the PJM and New England forward capacity markets in principle provide for local capacity requirements.[148] The PJM process has in general appeared to work better in this respect than the New England design. The most apparent limitations of the New England design have been 1) an initial design

147 See ISO New England Internal Market Monitor, 2011 Annual Markets Report. May 15, 2012, p.64 Table 3-17. And ISO New England, Forward Capacity Auction Results Filing, Section V in Docket ER12-1678-000. Submitted April 30, 2012.

148 By local capacity requirements we mean the aggregate level of capacity within a local region, not the capacity needed to be on-line to support voltage in local areas.

in which local capacity requirements were only enforced if there was insufficient existing capacity to meet the local capacity requirement and 2) local capacity requirements which were apparently set well below the actual reliability requirement. PJM appears to have been more forward looking in identifying potential transmission constraints and enforcing them in the RPM Base Residual Auctions in a timely manner.

The current New England forward capacity market design provides for the determination of local sourcing requirements to ensure that sufficient capacity is available to reliably meet load within transmission constrained subregions of New England.[149] The ISO New England FCM market design provided for the development of four capacity regions, and includes a process for ISO New England to identify additional capacity regions over time. The local sourcing requirement is determined by ISO New England prior to each forward auction for each load zone, accounting for relevant transmission limits and the existing capacity resources that are expected to be available.[150] These local sourcing requirements are filed with FERC at least 90 days prior to each forward auction.[151]

However, the initial New England FCM capacity market design only enforced these capacity zones and required that the local sourcing requirement actually be met if it was determined in advance of the auction that there was not enough existing capacity to meet the local sourcing requirement. This design for taking account of potential transmission constraints will inevitably fail to meet local capacity needs if the clearing price in the auction falls below the going-forward costs of some of the existing capacity. Moreover, ISO New England has apparently set some local sourcing requirements at levels too low to maintain reliability so it has had to contract out-of-market for local capacity when the auction prices fall

149 ISO New England also conducts a forward reserve market that also enforces locational requirements and interacts to a degree with its capacity market.
150 ISO New England, Transmission, Markets & Services Tariff, Sections III.12.2 and III.12.4.
151 ISO New England, Transmission, Markets & Services Tariff, Section III.12.3.

below the going-forward costs of capacity needed to maintain reliability even within regions for which the local sourcing requirement was enforced in the auction.

The problems with ISO New England's implementation of local sourcing requirements are not hypothetical problems. The unconstrained New England clearing prices have repeatedly fallen below the costs of capacity needed to maintain reliability in individual New England capacity zones. For example, only a Maine and Rest-of-Pool zone were modeled in the third and fourth New England auctions, so there was no local sourcing requirement enforced for the northeastern Massachusetts region and the auction cleared at prices below the offers of the Salem Harbor units.[152] However, ISO New England determined that it needed to keep the Salem Harbor units in service because they were actually needed to avoid transmission overloads in the Boston Subarea in Northeast Massachusetts.[153] The reliability problem appears to have been a shortage of aggregate capacity within the Northeast Massachusetts region rather than a local reliability problem such as voltage support in Salem, although the ISO New England reports are not completely clear. The local sourcing requirement for Northeast Massachusetts was raised substantially after the 3rd FCA[154] but this did not make any differences because it was not enforced and the actual capacity need perceived by ISO New England was still higher than the local capacity requirement.[155]

Similarly, Vermont Yankee should have set the clearing price for generation in Vermont in the fourth and fifth auctions, i.e. FCA 4 and 5. This did not happen, however, because there was no local requirement for Vermont. ISO New England only modeled a Maine and rest-of-pool capacity region in the fourth

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152 ISO New England, Forward Capacity Auction Results Filing, in Docket ER10-186-000 at p. 7. Submitted October 30, 2009.

153 See ISO New England, Forward Capacity Auction Results Filing, in Docket ER10-186-000 at p. 2. Submitted October 30, 2009, ISO-NE, Supplement to Forward Capacity Auction Results Filing-Testimony of Stephen J. Rourke, in Docket ER10-2477-000 at p. 7-29 and 9-21, Submitted September 17, 2010 and Patton, LeeVanSchaick, and Chen, 2011 Assessment of the ISO New England Electricity Markets. June 2012, p. 110.

154 ISO New England Internal Market Monitor, 2011 Annual Markets Report. May 15, 2012, p.76 Table 3-23.

155 ISO New England Internal Market Monitor, 2011 Annual Markets Report. May 15, 2012, p.76 Table 3-23 and ISO New England, Supplement to Forward Capacity Auction Results Filing, in Docket ER10-2477-000 at p. 12. Submitted September 17, 2010.

auction.[156] Because Vermont Yankee was an existing resource and did not submit a permanent delist bid, the tariff did not call for the reliability impact of its retirement to be analyzed prior to the auction. Vermont Yankee submitted a dynamic delist bid when the auction price fell below the 80 percent of CONE threshold for such bids by existing resources. Because no Vermont capacity zone was enforced in the auction, the auction clearing price could fall below the delist bid submitted by Vermont Yankee without causing the local capacity region to bind. As noted elsewhere, the auction cleared at the floor, 60 percent of the CONE used for that auction. ISO New England then determined that the continued operation of Vermont Yankee was necessary to maintain reliability.[157]

Although Vermont Yankee had already failed to clear in the fourth auction, ISO New England did not enforce a Vermont capacity zone in the fifth auction (conducted in June 2011 for the 2014 to 2015 capability year), again modeling only a Maine and Rest-of Pool region.[158] Nevertheless, ISO New England rejected Vermont Yankee's delist bid (i.e. its floor price for offering its capacity) for reliability reasons, described as thermal overloads on the lines that connect to the Vermont, New Hampshire and Western-Central Massachusetts load zones.[159]

Most recently, in the sixth forward capacity auction conducted in April 2012 for the 2015-2016 capability year, ISO New England once again modeled only a Maine and Rest-of-Pool zone. New England cleared as a single zone but the ISO found it necessary to keep in operation six resources in the Northeast Massachusetts/Boston load zone (five are demand response resources) whose offers exceeded the clearing price in the auction. The offers of these resources did not cause any zonal price separation in the capacity

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156 ISO New England, Supplement to Forward Capacity Auction Results Filing, in Docket ER10-2477-000 at p. 8. Submitted September 17, 2010.

157 ISO New England, Supplement to Forward Capacity Auction Results Filing-Testimony of Stephen J. Rourke, in Docket ER10-2477-000 at pp. 24-31. Submitted September 17, 2010.

158 See ISO New England, Forward Capacity Auction Results Filing, in Docket ER11 at p. 7. Submitted June 27, 2011.

159 See ISO New England, Forward Capacity Auction Results Filing, in Docket ER11-3891-000 Filing Letter at p. 9-10,Testimony of Stephen J. Rourke, at pp. 10-15 and 99, Submitted June 27, 2011 and Patton, LeeVanSchaick, and Chen, 2011 Assessment of the ISO New England Electricity Markets. June 2012, p. 113.

market, despite being needed to meet load in Northwest Massachusetts/Boston load zone because the zone was not enforced.[160] ISO New England has recently made some changes to address these chronic failures, in particular modeling at least four (of the eight load zones in the capacity market auction).[161] The Independent Market Monitor has pointed out the need to enforce all of the eight load zones as capacity zones and potentially enforce additional capacity zones.[162]

The conclusions we draw from this review are that the ISO New England capacity market design has several features that have been shown to work badly and should be avoided in any changes to the current New York ISO capacity market design. First, local capacity requirements need to be defined based on actual reliability requirements so that prices will separate if necessary to keep required capacity in operation. Second, capacity market boundaries which have been defined need to be modeled and enforced in the auction, letting auction bids determine whether the zones bind.

In addition, it is noteworthy that in most or all of the instances discussed above, the forward design of the ISO New England auction did not provide sufficient notice for replacement capacity or other options to be put in place to avoid the need to keep resources that did not clear in the auction in operation.

PJM also enforces local capacity requirements in its forward capacity auction. PJM initially enforced four local deliverability areas, the RTO, Mid-Atlantic plus APS, Eastern MAAC (PSE&G, JCP&L, PECO, Atlantic Electric, Del Marva Power and Light, Rockland Electric) and southeastern MAAC (Pepco and BG&E), but beginning in the 2010-2011 delivery year began enforcing 23 delivery areas. Capacity only needed to be deliverable within these regions. While most of these regions correspond to

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160 See ISO New England, Forward Capacity Auction Results Filing, in Docket ER12-1678-000, Filing Letter at p. 2-7.Testimony of Steven J. Rourke, at pp. 9-22, submitted April 30, 2012.

161 ISO New England, Docket FR12-953-000 Jan 31, 2012. Patton, LeeVanSchaick, and Chen, 2011 Assessment of the ISO New England Electricity Markets. June 2012, p. 106.

162 Patton, LeeVanSchaick, and Chen, 2011 Assessment of the ISO New England Electricity Markets. June 2012, p. 106 and 113-114.

transmission owner service territories or combinations of such territories, two regions divide transmission owner service territories into multiple regions, PSEG North and DPL south.[163] Through the 2015-2017 deliverability years, the requirements for nine local delivery areas were binding constraints in one or more auctions.

D. Interrelationship between Capacity Market and Energy and Ancillary Service Markets

PJM's projection of net energy and ancillary service revenues has accounted for around 36-43 percent of the total payment for capacity in most capacity zones over the past several PJM auctions.[164] It is not possible to readily compare the projected energy and ancillary service revenues used to calculate Net CONE to the hypothetical revenues of such a unit based on actual energy and ancillary service prices because the PJM State of the Market Report only reports hypothetical revenues for a combustion turbine dispatched based on overall RTO prices.[165]

The design of New England's capacity market is loosely intended to extract shortage revenues from capacity suppliers, so that capacity suppliers earn a capacity payment but cannot benefit from actions that elevate energy market prices. This was to be accomplished by deducting estimated "peak energy rents" from the capacity payment with a lag, so that resources that were available at the specified frequency during peak market conditions would break even on the peak energy rent charge and earn the capacity payment, while those that were often not available to meet load on peak would earn less than the full capacity payment. The peak energy rent deduction is not contemporaneous with the operating month, but

163 PJM, Manual 18: PJM Capacity Market Revision 15. June 28, 2012, Section 2.3.1.
164 Projected net energy and ancillary service revenues/(projected net energy and ancillary service revenues plus RPM auction clearing price)
165 See PJM State of the Market Report, Table 3-8 1999-2010, Table 6-2 2011. The Brattle Group's 2011 report presents calculations comparing the projected energy and ancillary service revenues to Brattle Group estimates of actual returns, indicating that the projected revenues greatly exceeded the revenues of existing more or less comparable combustion turbine units in the Eastern and southwestern MAAC regions given actual prices, See Figure 15 p. 87.

is calculated and recovered on a rolling 12 month average basis so it in principle eventually taxes away any energy market shortage revenues.[166]

The original formulas for calculating peak energy rents assumed that the hypothetical generation was gas fired and calculated peak energy rents based on spot gas prices. This formula imposed large losses on oil fired generation in New England when oil prices rose above gas prices and remained above gas prices as the oil fired generators were charged to recover an energy margin they never received. ISO New England and NEPOOL filed with FERC to change this aspect of the peak energy rent deduction in December 2010.[167]

The peak energy rent formula currently calculates the peak energy adjustment using a 22,000 btu/kwh heat rate and the higher of the price of ultra-low sulfur #2 oil in New York Harbor (plus 7 percent for transportation) or the day-ahead gas price at the Algonquin City Gate.[168] Because gas prices are currently typically considerably below corresponding oil prices, gas fired generation can earn substantial energy market rents without triggering peak energy rent payments.

E. Effectiveness in Ensuring that Resources will be Available for their Commitment Period

Under RPM, PJM is responsible for contracting for capacity through the forward auction, enabling PJM to ensure that the target level of capacity is contracted for in the forward auction. PJM verifies the increase in capacity transfer capability associated with transmission upgrades and upgrades must execute

166 ISO New England, Transmission, Markets & Services Tariff, Section III.13.7.2.7.1.1

167 ISO New England, ISO New England Inc. and New England Power Pool, Market Rule 1 Revisions Relating to the Peak Energy Rent Feature of the Forward Capacity Market, in Docket ER11, submitted December 21, 2010.

168 ISO New England, Transmission, Markets & Services Tariff, Sections III.13.7.2.1.1.1 (b), (i), (iii) and III.13.6.1.2.

a Facilities Study Agreement for the upgrade.[169] PJM also determines the maximum capacity that can be offered by capacity sellers.[170]

The PJM RPM design also provides a mechanism for generation developers to buy replacement capacity, either through bilateral contracts or through incremental auctions, in the event that their contracted project is delayed or becomes infeasible (as a result of permitting issues for example).[171]

In addition, beginning in the incremental auctions for the 2012-2013 capacity year, PJM began selling back in the incremental auctions, capacity that it determined was no longer needed to maintain reliability, based on more recent load forecasts.[172] Table 36 shows the net amount of capacity sold back by PJM in the auctions for the 2012-2013 and 2013-2014 years.

Table 36
Net Capacity Released by PJM

Net Repurchases of Capacity			
	2012-2013	2013-2014	2014-2015
1st Incremental	-60.3	-2494.9	-3050.8
2nd Incremental	-2376.8	-3602.1	
3rd Incremental	-1979.3	N/A	
Total	-4416.4	-6097	-3050.8

Source: 2012/2013 First Incremental Auction Results, Table 1
2012/2013 Second Incremental Auction Results, Table 1
2012/2013 Third Incremental Auction Results, Table 1
2013/2014 First Incremental Auction Results, Table 1
2013/2014 Second Incremental Auction Results, Table 1
2014/2015 First Incremental Auction Results, Table 2

169 PJM, Open Access Transmission Tariff, Attachment DD Sections 5.6.1(f) and 5.6.4.
170 PJM, Open Access Transmission Tariff, Attachment DD Section 5.6.6.
171 PJM Open Access Transmission Tariff, Attachment DD Section 5.4 (d)
172 The incremental auctions can also be used to purchase additional generating capacity if PJM were to determine that the load forecast was too low. PJM Open Access Transmission Tariff, Attachment DD Section 5.4 (c)

The total amount of capacity that has bought out of its forward capacity market obligation is even larger, as not all of the capacity buybacks were of capacity released by PJM; other buybacks were replaced by other resources seeking to provide capacity. Table 37 shows that gross buybacks were over 9000 megawatts for the 20112-2013 delivery year and are already over 10,000 megawatts for the 2013-2014 delivery year with the third incremental auction yet to be held.

Table 37
Gross Capacity Bought Back

	2012-2013	**2013-2014**	**2014-2015**
First Incremental	1749	4882.0	6849.9
Second Incremental	3214.6	5598.8	
Third Incremental	4382.8	NA	
Total	9346.4	10,480.8	6849.9

Source: 2012/2013 First Incremental Auction Results, Table 4
2012/2013 Second Incremental Auction Results, Table 4
2012/2013 Third Incremental Auction Results, Table 4
2013/2014 First Incremental Auction Results, Table 4
2013/2014 Second Incremental Auction Results, Table 4
2014/2015 First Incremental Auction Results, Table 6

As the delivery year approaches, a considerable proportion of the demand response that has cleared in the PJM forward RPM auctions has bought out of its delivery obligation, 1247.5MW out of 1826.6 for 2011 and 2253.6 out of 8740.9 for 2012.[173] This is an efficient response to over forecasts of needed capacity, with demand response able to buy out of its capacity obligation at a discount from the original clearing price.[174]

173 See Monitoring Analytics, LLC, Q2 State of Market Report for PJM, August 16, 2012, Table 4-8 p. 89.
174 We expect that it would generally be demand response that would buy out its obligation when excess capacity is procured in the forward auction as much of the costs of generation would be sunk while the cost of providing demand response by deferring consumption would not be sunk and could be avoided by buying out of the obligation. It is somewhat surprising that demand response does not constitute an even larger proportion of the resources that have bought out of their forward obligation given the extremely low capacity prices in these reconfiguration auctions, as it is difficult to envision the circumstances in which it would be economic to interrupt load in exchange for the very low prices in the reconfiguration auctions. It may be that much of the demand response which has not bought out of its forward obligations is providing demand response under third party contracts that require specific performance.

It makes sense from an economic perspective that a disproportionate amount of the capacity that has bought out of its capacity market obligation would be demand response. While the cost of communications and infrastructure might be sunk, the cost of reducing consumption is not yet sunk; in comparison, the cost of much new generating capacity would be sunk by the time of the third incremental auction in particular. From a market perspective, we would therefore expect to find that most of the capacity buying out of forward capacity sales in response to reduced PJM capacity requirements in the second and third auctions would be demand response, and existing capacity with high going forward costs that decides its continued operation is no longer economic. Indeed, given how low the capacity prices have been in the incremental auctions, it is somewhat odd that all demand response has not bought out of its obligation. This may be because the demand response has been contracted for under state or utility programs that require specific performance and do not permit the provider to buy out of the obligation.

The PJM market monitor has noted the existence of these large buybacks and the low buyback prices and has recommended a number of changes in capacity market obligations that would have the effect of making demand response offers in the forward capacity market more physical.[175] The intent of these proposed rule changes is presumably to increase the likelihood that all demand response bids clearing in the forward capacity auction could be available during the operating year if PJM did not subsequently reduce its capacity requirement, i.e. if the resources were needed to maintain PJM reliability.

However, one of the surprising elements of the incremental auction results is the high cost to PJM power consumers of the excess capacity procurement because the capacity sold in the forward capacity auction has typically been bought back in the incremental auctions at a small fraction of the original price. If these incremental auctions are well functioning competitive markets, these outcomes indicate that the

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175 See Joseph Bowring and Alexandra Salaneck, Analysis of Replacement Capacity for RPM Commitments, PJM Market Implementation Committee, January 9, 2013, p. 58.

marginal supplier buying out of its forward capacity market obligation has already incurred most of the costs associated with providing the capacity resource, hence its avoided costs are low.

This is a surprising outcome, particularly in the case of an obligation to provide demand response in a future year, as the required reductions in consumption do not have to be provided when the provider buys out of its obligation.[176] The kind of changes proposed by the PJM market monitor would increase the costs that demand response providers would have to incur prior to the operating year and hence further reduce the avoidable costs, further depressing the buyout prices in the incremental auctions and further increase the cost to PJM power consumers of excess forward capacity procurement.

This very high level of turnover in the capacity that initially cleared in the forward capacity market auctions portrayed in Tables 36 and 37 needs to be kept in mind when considering whether a forward capacity market provides a mechanism to ensure that specific generating resources remain in service. In PJM, there has been a very large amount of change in the identity of the resources initially clearing in the forward base residual auctions and the capacity that is in service during the operating year.

There has been a general tendency for incremental auction prices to be lower, often much lower, than the prices in the forward capacity market in which most capacity is procured. This has been particularly apparent in the years and capacity zones in which PJM has reduced its capacity requirement for the incremental auctions (i.e. sold back capacity). The potential for market participants to potentially earn substantial profits by selling capacity in the forward auction than buying out of the obligation in the subsequent incremental auctions gives rise to a risk that some supply offers in the forward capacity

176 As noted above, there are a variety of factors that could be contributing to this outcome, such as state programs that procure demand response for sale in the PJM capacity market and require specific performance, but identifying the relevant factors is not the focus of this report. We focus simply on the observed pattern in PJM, which the New York ISO would have to understand and address if it were to implement a forward capacity market.

market are in essence virtual bids that the market participant would not be able to cover with a capacity resource if PJM needed the capacity.

Capacity suppliers in PJM, whether generation, transmission or demand response are subject to paying deficiency charges if the capacity they are obligated to provide is not available for any or all of the delivery year.[177] The PJM tariff also imposes a credit requirement on entities seeking to supply capacity in an RPM auction from new generation resources, from transmission upgrades, from a new demand response resource, or from a resource external to PJM that has not yet contracted for firm transmission service.[178] No credit requirement is imposed on existing generation resources under the RPM design, the implicit premise being that the existing resource could be operated if necessary, even if it was uneconomic. There is a possibility, however, that this would not be the case for existing resources that clear in a forward auction but then could not operate because of environmental restrictions. There would be existing generating capacity to cover the supply obligation, but the existence of the capacity would not assure performance if it has no value because of the size of the investment needed to allow continued operation.

There have been one or more instances of demand response resources which apparently contracted with the State of Maryland to provide demand response in PJM's capacity market that were unable to meet their obligations to the State.

Under the FCM design, ISO-NE is responsible for procuring capacity through the forward auction, enabling ISO-NE to ensure that the target level of capacity is procured if it is available. Under the FCM design, each capacity resource must be qualified by ISO-NE prior to participation in the forward capacity auction. For new generator resources, this process entails submission of data including the expected

177 PJM, Open Access Transmission Tariff, Attachment DD Sections 8, 11 and 12.
178 PJM, Open Access Transmission Tariff, Attachment Q Sections IV A and B.

commercial operation date, the project location, the status of the project under generator interconnection procedures, the economic minimum limit of the resource, a location plan and a diagram of the plant and facilities. The resource owner must also show control of the project site for the duration of the relevant capacity period, submit a critical path schedule for the project, estimate required project financing, identify the expected source of financing and specify the expected closing date for project financing. In addition, the project sponsor must provide a list of all major components for the project and the date on which all major components have been or are expected to be ordered and a variety of other information.[179] There is a similar qualification process for import supply.[180]

Demand response resources must go through a similar qualification process, which includes submission of data. The required data includes the load zone location, estimated demand reduction value, demand resource type, source of funding and a measurement and verification plan.[181]

The ISO New England FCM design contains extensive provisions governing ISO New England monitoring of the development and construction progress of new capacity resources once they have been selected in the forward auction.[182]

One stated purpose of the extensive data submission process is to enable ISO New England to perform a detailed evaluation of each proposal to ensure that the proposed capacity assets can satisfy their obligations and that procured capacity is built and achieves commercial operation.[183] This ISO review of plans and schedules may assure that a proposed project could be built, but it does not ensure that the projects will be completed or completed within the required timeframe. The extent of ISO New England

179 See ISO New England, Transmission, Markets & Services Tariff, Sections III.13.1.1 and III.13.1.1.2 and ISO New England, Filing Containing Revisions to Market Rules Implementing FCM Settlement Agreement, in Dockets ER07-546-000 and ER07-547-000 at p. 20-27. Submitted February 15, 2007

180 See ISO New England Tariff, Market Rule 1, Sections III.13.1.3.3 and 13.1.3.5.

181 ISO New England, Transmission, Markets & Services Tariff, Section III.13.1.4.2

182 ISO New England, Transmission, Markets & Services Tariff, Section III.13.3.2.

183 ISO New England, Filing Containing Revisions to Market Rules Implementing FCM Settlement Agreement, in Dockets ER07-546-000 and ER07-547-000 at p. 10 and 24-25. Submitted February 15, 2007.

review and analysis required by the proposal was expected to impose significant resource burdens on the ISO. This burden has likely has not been as material as expected with respect to generation, because of the limited amounts of new generation offered into and clearing in the FCM auctions.[184] These monitoring costs also must be incurred for new demand response, of which there has been a considerable amount.

The ISO New England FCM design provides a mechanism for generation developers to buy replacement capacity, either through bilateral contracts or in annual reconfiguration auctions, in the event that their contracted project is delayed or becomes infeasible (as a result of permitting issues for example).[185] Both auction purchases and bilateral transactions are subject to review and approval by the ISO to ensure that the replacement resources satisfy New England reliability needs.[186] If a resource's capacity declines by more than 20 percent or 40 megawatts between the forward auction in which it sells capacity and the capacity procurement period, then the seller is obligated to replace the capacity through bilateral purchases or in the reconfiguration auction or to put in place a plan to restore the capacity.[187]

The ISO New England FCM tariff also incents new suppliers to meet their capacity obligations by imposing a credit requirement on entities seeking to supply capacity in an FCM auction from new generation resources or new demand response resources until such time as the resources are declared commercial and successfully tested for their capacity rating by ISO New England. Once new resources are successfully tested, they are treated as existing resources.[188] New capacity resources must provide $2000/MW of financial assurance in order to participate in the forward auction. If they are selected in the auction, then they must provide sufficient additional financial assurance to cover the calculated monthly

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184 ISO New England, Filing Containing Revisions to Market Rules Implementing FCM Settlement Agreement, in Dockets ER07-546-000 and ER07-547-000 at p. 9, 14, and 30-31. Submitted February 15, 2007.
185 ISO New England Transmission, Markets & Services Tariff, Section III.13.3.4
186 ISO New England Transmission, Markets & Services Tariff, Section III.13.5.1.1.3
187 ISO New England Transmission, Markets & Services Tariff, Sections III.13.4.2.1.3 and III.13.6.1.3.2
188 ISO New England, Transmission, Markets & Services Tariff, Section III, Exhibit IA, Section VB5

CONE payment for that auction (for one month). Fifteen days prior to the next forward auction the supplier is required to provide financial assurance covering the calculated monthly CONE payment (for the auction in which the capacity cleared) for two months. And 15 days prior to the next forward auction they are required to provide financial assurance covering the calculated monthly CONE payment (for the auction in which the capacity cleared) for three months.[189] This financial assurance will be drawn down by the ISO in various circumstances in which the capacity supplier fails to provide capacity.[190] The financial assurance provisions are intentionally not burdensome, as compliance is intended to be primarily assured through the ISO qualification and monitoring process.[191]

The ISO New England credit requirements for new generating capacity reflect the tension between imposing sufficiently high credit coverage requirements on new capacity to provide reasonable assurance that the generation project will go forward and raising the costs of new capacity offered in the auction through burdensome credit coverage requirements.

Resources must make a deposit in order to participate in the auction process, and comply with financial assurance policies.[192] If resources fail to participate in the auction, they also must reimburse the ISO for expenses incurred in evaluating their application.[193]

The ISO New England forward capacity market design includes annual reconfiguration auctions in which market participants can buy and sell capacity supply obligations in future operating years, allowing capacity suppliers that will be unable to deliver capacity sold in the forward auction to eliminate their liability or allowing high cost capacity supply to defer construction if lower cost replacement supply is

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189 ISO New England, Transmission, Markets & Services Tariff, Section III, Exhibit IA, Section VB2

190 See ISO New England Tariff, Market Rule 1, Exhibit IA, Section VC.

191 ISO New England, Filing Containing Revisions to Market Rules Implementing FCM Settlement Agreement, in Dockets ER07-546-000 and ER07-547-000 at p. 8 and 24. Submitted February 15, 2007.

192 ISO New England, Transmission, Markets & Services Tariff, Section III.13.1.9.

193 ISO New England, Transmission, Markets & Services Tariff, Section III.13.1.9.3.2.2.

available. The prices in these reconfiguration auctions have been far below the floor in the forward procurement auction which is expected since the price floor in the forward auction prevents the forward auction price from falling to the level at which the market clears.[194] ISO New England data shows that there has been a significant volume of trading in the annual and monthly reconfiguration auctions, although this may in part reflect the fact that the forward auction price has not been a true clearing price in any of the auctions to date.[195]

F. Effectiveness in Incenting Resource Performance during the Obligation Period

Under PJM's RPM capacity market design a system of peak-hour availability charges and credits is intended to provide improved incentives (relative to the prior PJM UCAP market design) for generation resources to be available during stressed system conditions. The PJM RPM tariff identifies roughly 500 hours during the year that are potentially high load periods.[196] The calculation of availability will limited to the subset of these high load hours during which the resource would have been economic to operate based on its cost-based offer price.[197] Generators whose availability during these hours is less than their Equivalent Demand Forced Outage Rate (EFORd) will have their resource adequacy payment reduced proportionately.[198]

While these incentives operated during 2011 to reduce the forced outage rate during these hours below the overall forced outage rate, indicating that capacity suppliers are taking steps to keep their units on line

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194 The PJM RPM tariff defines these hours as non-holiday weekdays 2-7 p.m. in June- August and 7 a.m.-9 a.m. and 6-8 p.m. in December through January; See PJM, Open Access Transmission Tariff, Attachment DD Section10.

195 PJM, Open Access Transmission Tariff, Attachment DD Section 10(e).

196 The PJM RPM tariff defines these hours as non-holiday weekdays 2-7 p.m. in June- August and 7 a.m.-9 a.m. and 6-8 p.m. in December through January; See Attachment DD, Section 10.

197 PJM Attachment DD, Section 10 (e).

198 There are exceptions for generation resources that are not available for reasons outside management control, such as transmission outages, gas pipeline outages, etc.

during these peak hours,[199] there are some apparent problems with these incentives. In particular, the current PJM rules are applied such that a “lack of fuel” can be designated an “out of management control outage” that is not included in the resource’s peak-hour forced outage rate.

The PJM Independent Market Monitor’s 2011 State of the Market Report for PJM recommended that “the performance incentives in the RPM Capacity Market be strengthened,” and that generation resources be paid on the basis of whether they produce energy when called upon during hours defined as critical.[200] The Independent Market Monitor expressed a particular concern regarding the impact of gas availability related outages that are not considered forced outages in PJM’s capacity market design.[201] The Independent Market Monitor discusses “Out of Management Control” outages at length in volume 2 of the report and recommends that “PJM propose eliminating lack of fuel as an acceptable basis for an OMC outage.”[202] The report shows that lack of fuel accounted for 5.5 percent of all forced outages in PJM in 2011,[203] which suggests that these fuel supply incentives are important.

While treating outages due to “lack of fuel” as forced outages, rather than as “out of management control outages,”[204] would improve generator performance incentives with such a change, the incentive to keep a resource on line when it is most needed would still be less than ideal because the application of the

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199 Monitoring Analytics, LLC., 2011 State of the Market Report for PJM. March 15, 2012, Volume 2 p. 116-117
200 Monitoring Analytics, LLC., 2011 State of the Market Report for PJM. March 15, 2012, Volume 2 p. 91
201 Monitoring Analytics, LLC., 2011 State of the Market Report for PJM. March 15, 2012, Volume 1 p.19
202 Monitoring Analytics, LLC., 2011 State of the Market Report for PJM. March 15, 2012, Volume 2 p. 90-91 and 115-116.
203 Monitoring Analytics, LLC., 2011 State of the Market Report for PJM. March 15, 2012, Volume 2 p. 30 Table 4-30.
204 There is an exception in the instance in which the lack of fuel is actually due to gas pipeline outages, rather than as the market monitor points out, a lack of firm transaction rights on the pipeline or a decision to sell gas on the spot market, See Monitoring Analytics, LLC, 2011 State of the Market Report for PJM, March 15, 2012, Volume 2, p. 116

incentive would be spread over all peak-hours, and during many of these hours the system would be under little or no stress.[205]

The PJM Peak-hour availability incentives accommodate the needs of energy-limited resources by allowing these resources, within the constraints of the overall PJM market power mitigation plan, to limit the amount of energy they are dispatched to provide during the peak hours by setting offer prices that limit their dispatch, without being penalized for reduced peak-hour availability.[206]

The ISO New England FCM design includes day-ahead and real-time bidding obligations for capacity resources similar to those in the New York ISO capacity markets. Thus, generation resources must be offered in the day-ahead market and must also be offered in real-time.[207] Import supply must also be offered in the day-ahead market and at least 16 hours per weekday in the real-time market.[208] Intermittent resources, on the other hand, must submit bids in real time but have the option of submitting bids in the day-ahead market. Intermittent resources are required, however, to submit day-ahead supply projections.[209] Fully delisted resources, i.e., resources none of whose capacity has been purchased in the capacity market, are not obligated to offer their output in either the day-ahead or real-time market.[210] Demand resources, on the other hand, are not permitted to submit supply offers in either the day-ahead or real-time markets.[211]

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205 PJM's problems with gas availability probably also reflect features of the PJM energy market design, particularly the inability of market participants to adjust offer prices during the operating day to reflect intra-day gas costs. This problem is not present in the New York ISO market design as market participants have the ability to modify their energy offers up to 75 minutes prior to the operating hour, enabling them in principle to submit energy offers reflecting current gas prices. However, there is a lag in the availability of the indexes used to apply market power mitigation, so generators subject to seller market power mitigation can at times be prevented from submitting offers reflecting current gas prices.

206 Unlike in New York, however, resources with energy limits that can become more or less binding over the course of the operating day cannot adjust their offer prices from hour to hour.

207 ISO New England, Transmission, Markets & Services Tariff, Section III.13.6.1.1.1.

208 ISO New England, Transmission, Markets & Services Tariff, Section III.13.6.1.2.1. The requirement differs slightly between dispatchable and fixed energy transactions.

209 ISO New England, Transmission, Markets & Services Tariff, Section III.13.6.1.3.1.

210 ISO New England, Transmission, Markets & Services Tariff, Section III.13.6.1.1.1.

211 ISO New England, Transmission, Markets & Services Tariff, Section III.13.6.1.5.

In addition, a system of performance payments and charges based on resource availability during shortage conditions is intended to provide improved incentives (relative to the prior ISO-NE UCAP market design) for generation resources to be available during stressed system conditions under the FCM design. The application of charges is based on resource availability during shortage events, which are essentially hours of reserve shortage.[212] Generators whose availability during these hours is less than their qualified capacity will have their resource adequacy payment reduced proportionately.[213] Units that are on-line and available for dispatch or off-line and available to come on line within 30 minutes will be treated as available up to their economic maximum limit. There are a number of special rules governing the circumstances in which resources will not be assessed penalties because the resource was not committed as a result of a transmission outage (on the transmission grid, not of the generator lead), because the resource is unavailable due to an approved maintenance outage (during the normal maintenance seasons), or because it was offered but not committed in the day-ahead market (and has a notification plus start-up time of 12 hours or less).[214]

The original FCM filing did not permit economic outages. If offer caps prevented a resource from offering its capacity at a price reflecting its actual costs (such as during periods when winter gas balancing rules are in effect and spot gas prices are extremely high), then capacity resources were to offer their supply at the bid cap and notify ISO-NE that their actual costs were higher.[215] This provision has since been deleted from the ISO New England Tariff and economic outages of gas fired generation during stressed system conditions when the capacity may be needed to maintain reliability have continued to be a problem in New England as discussed below.

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212 ISO New England, Transmission, Markets & Services Tariff, Section III.13.7.1.1.1.

213 There are exceptions for generation resources that are not available for reasons outside management control, such as transmission outages, gas pipeline outages, etc.

214 ISO New England, Transmission, Markets & Services Tariff, Section III.13.7.1.1.3

215 ISO New England, Transmission, Markets & Services Tariff, Section III.13.6.1.1.3. The ISO New England February 15, 2007 Filing Letter noted that the details of how this provision would operate remain to be worked out, p. 20.

As in PJM, the FCM availability incentives accommodate the needs of energy-limited resources by allowing these resources to, within the constraints of the overall ISO-NE market power mitigation plan and offer price rules to use their offer price to limit the amount of energy they are dispatched to provide during shortage events, without being penalized for reduced availability as long as the resource is on-line and available to be dispatched for energy during the shortage event (and thus providing reserves if it is not dispatched for energy).[216]

Resource qualified capacities are determined by the ISO rather than the resource owner. It is therefore possible for the owner of an existing resource to be assigned capacity obligations that exceed the performance capabilities of the resource. One source of such overrating, basing ratings on capacity at 90° Fahrenheit, is addressed by provisions permitting resource owners to submit delisting bids for this capacity at 2 times CONE.[217] Since capacity payments cannot go negative under the ISO New England tariff,[218] absent market power there does not appear to be any financial incentive for capacity suppliers to delist capacity ranges in which the resource might not actually be able to operate.

The qualified summer capacity of existing intermittent resources in the ISO New England FCM capacity market is determined by the median output during hours ending 14 through 18 of the months June through September and all shortage event hours for the relevant location, while the qualified winter capacity is determined by the median output for hours 18 and 19 for the months of October through May and all shortage event hours for the relevant location.[219]

The qualified summer capacity of demand response resources in the forward auction will be based on data for the months of June, July and August and the qualified winter capacity will be based on data for

216 As in PJM, energy-limited resources cannot adjust their offer prices from hour to hour if their energy limit becomes more or less binding over the operating day.
217 ISO New England, Transmission, Markets & Services Tariff, Section III.13.1.2.3.2.4.
218 ISO New England, Transmission, Markets & Services Tariff, Section III.13.7.2.7.1.1.2.
219 ISO New England, Transmission, Markets & Services Tariff, Section III.13.1.2.2.2.

December and January.[220] The performance obligation of demand response resources is year round. Demand response resources whose ability to reduce consumption is based on summer load patterns may need to supply capacity through a composite offer of summer demand response, winter demand response and/or winter generating capacity.[221]

The ISO New England Internal Market Monitor's 2011 Annual Markets Report, May 15, 2012 noted repeated problems over the 2010-2012 period with gas fired resources that declared themselves unavailable in real-time because gas prices levels made their operation uneconomic.[222] While these performance problems are likely in considerable part due to ISO New England market rules which prevent gas fired suppliers from adjusting their offer prices to reflect the actual cost of gas during the operating day, they also reflect weak performance incentives in the capacity market.[223]

The performance under the FCM design of New England capacity resources in general, and the demand response resources in particular, has not yet been fully tested because the actual peak loads during the summers of 2010 and 2011 were well below the peak load forecast used to procure capacity in the FCM auctions, and the amount of capacity offered in these auctions at the price floor, and available during the operating years was even larger. Hence, the actual margin of available resources over peak demand has been much larger than intended. ISO New England estimated that demand response reduced the peak load from 29,533 megawatts to 27,707 megawatts, or 1826 megawatts, on July 22, 2011. This would have been a 65.7% performance for the 2778 megawatts of demand response cleared in the 2011-2012 FCA if all of that demand response was activated.[224] It may be a number of years before the capacity

220 ISO New England, Market Rule Section III., 13.7.1.5.4.1 and III.3.7.1.5.4.2
221 See ISO New England Tariff, Market Rule 1, Section III.13.1.5.
222 ISO New England, Internal Market Monitor, 2011 Annual Markets Report, May 15, 2012 p. 74.
223 ISO New England has proposed a variety of design changes to address these types of performance problems. See for example, ISO New England FCM Performance Incentive, October 2012.
224 See David Ehrlich, ISO New England, "ISO New England RSP12 Long-run Forecast of Energy and Seasonal Peaks," February 15, 2012 p. 7.

margin in New England falls to the target level and it is seen if all of the capacity supplied in these auctions, particularly the demand response, is able to meet its performance obligations.

G. The Relative Role of Administrative Rules in Determining Market Prices

In New England the capacity market price has been determined by the price floor in every year so far. The New England FCM has a large number of other special administrative rules that would cap prices, or calculate artificial prices that do not clear the market in various situations. Most of these other rules have had little if any significance because the auction has cleared at the price floor every year.

All existing capacity participating in PJM RPM auctions has been subjected to market power mitigation in every auction to date. This has generally not resulted in the auction price being determined largely by these mitigated offers because of the number of resources needing expensive environmental upgrades to remain in operation, so auction prices have appeared to generally be determined by the offers of demand response, new generation and/or existing generation with some kind of repowering or environmental cost determining their offer price.

H. Rules to Mitigate the Exercise of Market Power

Finally, we compare the PJM and ISO New England rules governing the mitigation of potential buyer-side and seller-side market power, the degree to which these rules have been applied, and the apparent role of these rules and other administratively defined rules (including demand curve parameters, price floors, and rules regarding the circumstances in which existing capacity can bid as new capacity) in determining clearing prices. This assessment is limited to publicly available data.

1. Seller Market Power

PJM's analysis of seller market power has two parts. The first part is that the PJM Market Monitor applies a preliminary market structure screen prior to each RPM Base Residual Auction.[225] The preliminary screen applies three tests: 1) no capacity resource owner has a market share exceeding 20%; the HHI is 1800 or lower; there is no group of three suppliers which would be jointly pivotal.[226] The RTO and MAAC regions typically pass the first two screens, but they, and all other regions, typically fail the 3 pivotal supplier test.[227] If a region fails the preliminary screen all capacity owners must submit avoidable cost data for resources for which they intend to submit non-zero capacity offers,[228] and all offers are mitigated based on these cost data. Because the test withholds all of the supply of the three largest capacity suppliers from the market, this test will be triggered unless there is a substantial surplus of capacity. This has been the case, and the application of the three pivotal supplier test has had the result that every seller's offer price for existing capacity has been subject to mitigation in almost every region in every auction.[229]

The PJM market power mitigation design has provisions concerning the determination of "avoidable cost" for the purpose of capping seller offers include provisions for including costs associated with investments needed for the resource to continue operating.[230] These provisions allow resources to submit offers reflecting these staying in business costs and in practice a substantial amount of existing capacity has not cleared in the recent auctions.

225 Attachment DD section 6.3 (a) i
226 Monitoring Analytics, 2011 State of the Market Report for PJM, March 15, 2012, p. 95.
227 Monitoring Analytics, 2011 State of the Market Report for PJM, March 15, 2012, p. 95, table 4-7.
228 Monitoring Analytics, 2011 State of the Market Report for PJM, March 15, 2012, p. 95
229 The only exceptions have been the EMAAC region in the 2012/2013 Base Residual Auction and the MAAC region in the 2014-2015 Base Residual Auction. See Monitoring Analytics, LLC., 2011 State of the Market Report for PJM. March 15, 2012, p. 96.
230 See PJM Open Access Transmission Tariff, Attachment DD Section 6.8, particularly APIR and Mandatory Cap Ex Option

ISO New England in theory allows existing capacity to be withdrawn from the forward capacity market when the clearing price falls below at 80% of the administratively determined CONE without regard to going-forward costs or whether the supplier has market power. If the value of CONE used in the auction were set at a level reflecting the cost of new capacity, 80 percent of CONE would be a relatively high level for assumed going-forward costs. In fact, however, competition in the New England capacity market has been so intense, in part because the large amount of excess capacity, the capacity prices have consistently cleared at the price floor (60 percent of CONE) despite the ability of suppliers to delist (withdraw) existing capacity from the auction at .8 CONE.[231] Moreover, because prior to the changes in the FCM design filed in Feb 22, 2010,[232]the FCM design called for CONE to be reset for each auction based on the CONE and clearing price in the prior auction, the repeated instances of FCM auctions clearing at the floor price ratcheted down the CONE, so the 80 percent of CONE threshold had fallen to 80 percent of 66 percent of the original CONE value, or slightly more than 52 percent of the original CONE by FCA 3.[233]

The FCM proposal has extensive rules governing the circumstances in which previously existing generating capacity can be treated as new capacity for the purpose of the capacity auction. In particular, capacity at an existing generation facility can be treated as new capacity for the auction if substantial investments are made in the existing facility, if the capacity reflects an increase in the capacity of the resource, or if the capacity reflects a restoration of derated capacity.[234]

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231 It should be kept in mind, however, that ISO New England has enforced only the Maine export capacity submarket in its auctions to date. Had ISO New England enforced the regional markets, there might have been more potential for profitable economic withholding of capacity at 80 percent of CONE.

232 ISO New England, Various Revisions to FCM Rules Related to FCM Redesign, in Docket ER10-787-000 at p. 7. Submitted February 22, 2010.

233 See ISO New England, Transmission, Markets & Services Tariff, Section III.13.2.4 (b) and ISO New England Market Monitoring Unit, Review of the Forward Capacity Market Auction results and Design Elements. June 5, 2009, p. 35.

234 See ISO New England, Transmission, Markets & Services Tariff, Sections III.13.1.1.1.2 and III.13.1.1.1.3.. As noted above, a considerable amount of the “new capacity” clearing in the FCA was actually existing capacity treated as new pursuant to these rules.

Existing generation resources that do not qualify as new capacity and that do not want to be price takers in the forward auction, must submit static delist bids or permanent delist bids. Delist bids in excess of 80% of CONE are subject to review by the market monitor.[235] Existing generation resources seeking to permanently withdraw from the capacity market can submit permanent delist bids which are also subject to review by the market monitor if they exceed 80 percent of CONE; however, they will be presumed to be competitive if they are less than 1.25 times CONE unless the market monitor determines that the delisting is an attempt to manipulate the forward capacity auction.[236] Existing capacity resources can submit "dynamic delisting bids" during the auction if the clearing price falls below 80 percent CONE.[237] Delisting resources are also subject to a reliability review and will not be allowed to withdraw from the capacity market if their continued operation is determined to be needed to maintain reliability.[238]

These ISO New England provisions constraining the offer prices of existing resources are presumably intended to prevent physical or economic withholding by the owners of generation resources. Existing generation resources seeking to sell capacity outside New England must submit an export bid in the forward auction. Export bids in excess of 80% of CONE are subject to review by the market monitor.[239]

The market monitor reviews generation delisting bids to determine whether the bids are consistent with the resource's net risk adjusted going-forward costs. The FCM design also includes rules governing the evaluation of a delisting resource's risk adjusted going-forward costs and opportunity costs.[240] All delisting bids above the safe harbor levels of 80 percent of CONE for static delisting bids and 125 percent of CONE in the case of permanent delisting bids will be subject to this review of going-forward costs, without regard to the potential for the exercise of market power.

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235 ISO New England, Transmission, Markets & Services Tariff, Sections III.13.1.2.3.1.1, III.13.2.3.2(d), and III.13.1.2.3.2.1.

236 ISO New England, Transmission, Markets & Services Tariff, Sections III.13.1.2.3.1.2 and 13.1.2.3.2.1.

237 ISO New England, Transmission, Markets & Services Tariff, Section III.13.2.3.2(d).

238 ISO New England, Transmission, Markets & Services Tariff, Sections III.13.1.2.3.1.1; 13.1.2.3.1.2 and 13.2.5.2.5.

239 ISO New England, Transmission, Markets & Services Tariff, Section III.13.1.2.3.1.3.

240 ISO New England, Transmission, Markets & Services Tariff, Section III.13.1.2.3.2.

Similarly, the rules governing the determination of qualified capacity are intended to preclude physical withholding.[241] The qualified capacity of new capacity resources will be determined by ISO-NE based on information provided to it.[242] The qualified capacity of existing capacity will be determined by the median of the resource's claimed capability rating for the most recent five years (at the time of the auction), the median of the summer ratings being used to determine the qualified capacity for the summer period and the median of the winter ratings being used to determine the qualified capacity for the winter period.[243]

The New York ISO's process for mitigating seller market power is much more focused than the PJM or ISO New England rules. The New York ISO's seller market power mitigation rules currently apply to In-City constrained region and only to suppliers with 500 megawatts or more of capacity, that might plausibly seek to exercise market power.[244]

For the purposes of the capacity market, a supplier is pivotal if it controls 500 megawatts or more of UCAP and some portion of that UCAP is necessary to meet the New York Locational minimum installed capacity requirement in a spot market auction.[245] This is a single pivotal supplier test, as opposed to the three pivotal supplier test applied by PJM. Capacity subject to mitigation must be offered at the higher of

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241 ISO New England, Filing Containing Revisions to Market Rules Implementing FCM Settlement Agreement, in Dockets ER07-546-000 and ER07-547-000 filing letter at p. 37-38. Submitted February 15, 2007.

242 ISO New England, Transmission, Markets & Services Tariff, Sections III.13. 1.1.2.5.

243 See ISO-NE, Transmission, Markets & Services Tariff, Sections III.13.1.2.2.1.The claimed capability is subject to review by the market monitor if it is reduced below historical levels; see Section 13.1.7

244 New York Independent Service Operator, Market Services Tariff, Attachment H Section 23.2.1 "Definitions-Mitigated UCAP". The New York ISO has filed provisions that would also apply mitigation to sellers of capacity located in new capacity zones created in the future, see New York ISO filing, June 29, 2012 in Docket Nos. ER04-449 and ER12-360.

245 New York Independent Service Operator, Market Services Tariff, Attachment H Section 23.2.1 "Definitions-Pivotal Supplier".

the UCAP offer reference level[246] or the agreed upon going-forward costs of the resource.[247]

2. Buyer Market Power

We have discussed the potential for the exercise of buyer-side market power in Section IIC above in connection with our discussion of the New York ISO's buyer-side market power mitigation rules. This section describes the treatment of buyer-side mitigation in PJM and New England.

a. PJM

Under PJM's RPM capacity market design there is a concern that the potential for buyer manipulation of clearing prices is potentially as much a threat to the efficiency of the RPM market design as is the potential for seller manipulation.

The Federal Energy Regulatory Commission recognized the potential problem with buyer-side market power in PJM. The principal tool PJM uses to address buyer manipulation is through "… PJM's Minimum Offer Price Rule (MOPR), which is the mechanism that seeks to prevent the exercise of buyer market power in the forward capacity market by ensuring that all new resources are offered into PJM's Reliability Pricing Model (RPM) on a competitive basis. The MOPR imposes a minimum offer screen to determine whether an offer from a new resource is competitive."[248]

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246 The UCAP reference level is the price at which the In City supply would clear on the ICAP demand curve for New York City; see NYISO, Market Services Tariff, Attachment H Section 23.2.1 "Definitions-UCAP Offer Price Level".
247 New York Independent Service Operator, Market Services Tariff, Attachment H Sections 23.4.5.2 and 23.4.5.3.
248 PJM, Order on Compliance Filing, Rehearing, and Technical Conference Washington D.C., ERL-2875 (MOPR Order), ¶2.

The essence of the MOPR is to impose a mitigated offer for any new generation submitting an offer in the RPM auction below the level permitted by the MOPR rule. The underlying idea is that new generation with a separate contract outside the PJM market could be used to manipulate the auction capacity price if the higher costs paid under a contract allowed or even required the capacity supplier to submit lower offers into the RPM that would depress the competitive market-clearing price in the auction. If such manipulative offers were be mitigated to reflect arm's length competitive economics, the MOPR would remove the incentive to manipulate the RPM and would meet the FERC objective to replicate the competitive outcome.

The difficulty with the MOPR arises in practical implementation in identifying the elements that distinguish a legitimate competitive offer from a manipulative offer, given the myriad possible alternative business models proffered as justifications for low bids in the auction. For example, a utility could argue that it has a conservative policy for self-supply that justifies new construction. A public power participant could argue for a lower cost of capital than that used to define the MOPR floor. And so on. The very design of the RPM demand curve and its reference CONE contains compromises that attempt to aggregate across many decisions about intra-zonal variations in energy prices, alternative possible views about the level of energy prices and ancillary service payments, future regulatory risks, and real differences in the cost of capital. Since the participants in the RPM are offering real plants, not compromise average plants, there can also be real differences in offer price levels relative to the MOPR thresholds arising from differences in plant characteristics and costs that may be hard to distinguish from uncompetitive attempts to manipulate the markets.

The broad approach to setting the MOPR rules involves a tradeoff between bright line tests that are arbitrary but allow for some rough justice, and more flexible rules intended to allow for a wide range of possible exceptions. In an initial effort to improve the MOPR design, FERC approved a set of MOPR rules that encompassed a great deal of potential flexibility. These include:

- Elective Opt out. "The purpose of the Fixed Resource Requirement (FRR) Alternative is to provide a Load Serving Entity (LSE) with the option to submit a FRR Capacity Plan and meet a fixed capacity resource requirement as an alternative to the requirement to participate in the PJM Reliability Pricing Model (RPM), which includes a variable capacity resource requirement."[249]
- Automatic Exemptions for sell offers for "nuclear, coal, integrated gasification combined cycle, hydroelectric, wind or solar facilities."[250]
- Automatic Exemptions for sell offers that are at least at 90 percent of the CONE.[251]
- Elective Exception. "A sell offer below the MOPR screen price shall be permitted and not be re-set if the capacity market seller obtains a determination from PJM prior to the RPM Auction that the seller offer is permissible because the offer is consistent with the competitive, cost-based, fixed net cost of new entry were the resource to rely solely on revenues from PJM-administered markets." [252]

The elective exception imposes on the PJM Independent Market Monitor (IMM) and PJM a requirement to analyze and evaluate the full underlying economics of the proposed offer. The flexibility and extent of this evaluation appears in the description of what must be considered:

> "The request also shall include all revenue sources relied upon in the sell offer to offset the claimed fixed costs, including, without limitation, long-term power supply contracts, tolling agreements, or tariffs on file with state regulatory agencies, and shall demonstrate that such offsetting revenues are consistent, over a reasonable time period. In making such demonstration, the capacity market seller may rely upon forecasts of competitive electricity prices in the PJM Region based on well-defined models that include fully documented estimates of future fuel prices, variable operation and maintenance expenses, energy demand, emissions allowance prices,

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249 PJM, Manual 18: PJM Capacity Market Revision 14. February 23,2012, Section 11.11.1. This option applied to 14,406 MW in the BRA cycle for 2015/2016, relative to a total reliability requirement of 177,184 MW PJM, "2015/2016 RPM Base Residual Auction Results," PJM DOCS #699093, May 17, 2012, p. 26.
250 PJM, Manual 18: PJM Capacity Market Revision 14. February 23,2012, Section 5.3.5.
251 PJM, Manual 18: PJM Capacity Market Revision 14. February 23,2012, Section 5.3.5.
252 PJM, Manual 18: PJM Capacity Market Revision 14. February 23,2012, Section 5.3.5.

and expected environmental or energy policies that affect the seller's forecast of electricity prices in such region, employing input data from sources readily available to PJM and the Market Monitoring Unit. Documentation for net revenues also may include, as available and applicable, plant performance and capability information, including heat rate, start-up times and costs, forced outage rates, planned outage schedules, maintenance cycle, fuel costs and other variable operations and maintenance expenses, and ancillary service capabilities. …

"An evaluated sell offer shall be permitted if the information provided reasonably demonstrates that the sell offer's competitive, cost-based, fixed, net cost of new entry is below the minimum offer level, based on competitive cost advantages, including, without limitation, competitive cost advantages resulting from the capacity market seller's business model, financial condition, tax status, access to capital or other similar conditions affecting the applicant's costs, or based on net revenues that are reasonably demonstrated to be higher than those used by PJM to develop the minimum offer level. Capacity market sellers shall be asked to demonstrate that claimed cost advantages or sources of net revenue that are irregular or anomalous, that do not reflect arm's-length transactions, or that are not in the ordinary course of the capacity market seller's business are consistent with the standards of this subsection. Failure to adequately support such costs or revenues so as to enable PJM to make a determination will result in denial of an exception by PJM."[253]

This elective exception process was invoked by bidders as soon as the procedure was put in place, in time for the RPM Base Residual Auction for the 2015/2016 cycle. Although the details are not publicly available, submissions by the IMM indicate that in some cases the offer prices were deemed inconsistent with the MOPR and in other cases the exception was granted to permit offer prices below the MOPR screen. The results of the auction were a surprise. For example, PJM calculations set the MOPR UCAP screen for combined cycle gas units at $242.07/MW-day and $168.75/MW-day in EMAAC and SWMAAC, respectively.[254] This compares with the Base Residual Auction market-clearing price of $167.46/MW-day in both regions.[255] Subsequent analysis by PJM indicated that the differences between the CONE screen and the Base Residual Auction market-clearing prices could be explained largely by different input assumptions about forward electricity prices, gas prices, and the cost of capital.[256]

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253 PJM, Manual 18: PJM Capacity Market Revision 14. February 23, 2012, Section 5.3.5.

254 Paul Sotkiewicz, "MOPR and Economics of New Entry in PJM," UBS Electric Utilities and IPP Group Presentation, New York, June 12, 2012, p. 14.

255 PJM, 2015/2016 RPM Base Residual Auction Results, PJM DOCS #699093, May 17, 2012, p. 14.

256 Paul Sotkiewicz, MOPR and Economics of New Entry in PJM. UBS Electric Utilities and IPP Group Presentation, New York, June 12, 2012.

This outcome is a telling commentary on the PJM MOPR rules if the CONE screen can be off by roughly 50 percent as a result of differences in these assumptions.

b. ISO New England

With regard to buyer market power (monopsony), the original ISO-NE FCM rules also contained provisions for the market monitor to review offer prices for new generation or demand response resources that were less than 75 percent of CONE,[257] but these provisions had limited, if any, practical significance given the ability of LSEs to self-supply capacity (i.e., offer capacity at a price of zero).

If the market monitor determines that an offer is not consistent with the going-forward cost of the unit, then the capacity clearing from that offer was to be considered to be out-of-market under the alternative price rule.[258] The alternative rule would set the price at the lower of 1 cent under the price at which the last new generating, import or demand resource withdrew from the auction or at CONE.[259]

The New England FCM capacity market design does not include an elastic capacity demand curve. Instead, the capacity requirement is fixed. As part of the design determined in the stakeholder process, the FCM included a minimum price floor for the clearing price, viewed as a deminimis price level. This price floor was originally scheduled to be eliminated after FCA 3 but was subsequently extended.[260] Because the CONE is reset after each auction based on the auction clearing price as noted above, this price floor has been ratcheting down over time. At the time of the design of the FCM it was presumably

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257 ISO New England, Transmission, Markets & Services Tariff, Sections III.13.1.1.2.2.3, III.13.1.1.2.6, and III.13.1.4.2.4.
258 ISO New England, Transmission, Markets & Services Tariff, Sections III.13.1.1.2.2.3, III.13.1.1.2.6, III.13.1.3.5.6, and III.13.1.4.2.4.
259 ISO New England, Transmission, Markets & Services Tariff, Sections III.13.2.7.8.
260 ISO New England, 131 FERC ¶ 61,065 at p. 19. Issued April 23,2010.

anticipated that the clearing capacity price would converge to the cost of new entry. As reported by the market monitor, however, this has not proved to be the case.

> "One of the assumptions in the FCM design is that the capacity price would converge to the cost of new entry. Before the implementation of the FCM, the industry assumed that the cost of new entry would be determined by the cost of a new peaking unit. Under this assumption, few resources would be added if prices in the capacity market did not rise to the cost of new generation. The activity in the New England market since the start of the transition period belies this assumption. Most new capacity (about 4,600 MW) has been demand resources and imports, with costs apparently far below the consensus cost of new generation."[261]

For example, in the most recent Forward Capacity Auction (FCA 6), for the period 2015, the requirement of 33,456 MW was met at the floor price of $112.90/MW-day ($3.434/kW-Mo.).[262]

These low clearing prices appear to result in part from the treatment of buyer market power in New England. The ISO-NE refers to as out-of-market (OOM) offers that have a separate payment to cover some of the costs of new capacity and hence are able to submit offers in the FCM that are lower than the resource's full costs, thereby, reduce the market-clearing price in the FCM. This was perceived as a mechanism for the exercise of buyer market power and lead to several complaints at FERC and extended litigation at FERC.[263]

As a result of this process, the New England parties underwent an extensive period of negotiation to develop an improved mitigation rule directed at the exercise of buyer market power. The result was an innovative variant of an Alternative Capacity Pricing model proposed as a more comprehensive reform. The essential idea is summarized by the FERC review of the alternative capacity price rule (APR) under this model.

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261 ISO New England Market Monitoring Unit, 2011 Annual Markets Report. May 15, 2012, p. 69

262 ISO New England, Forward Capacity Market (FCA 6) Result Report. April 4, 2012, p. 3.

263 See New England Power Generators Association Inc., Complaint Requesting Fast Track Processing, in Docket ER10-50-000. Submitted March 23. 2010 and New England Power Generators Association Inc., Motion to Intervene and Protest, in Docket ER10-787-000. Submitted March 15, 2010.

> "Under the revised APR mechanism, all resources that clear in the FCA receive a Capacity Supply Obligation, with new resources receiving capacity payments for a fixed time frame of five consecutive Capacity Commitment Periods at the price from the first FCA in which the resource clears. ISO-NE states that new resources receive this price for a fixed period to provide these resources with an incentive to offer based on the cost of entry rather than based on the possibility of obtaining the higher Alternative Capacity Price in subsequent FCAs.
>
> "Under the revised APR mechanism, existing resources that did not clear in the FCA but that offered in an FCA at or below the Alternative Capacity Price also receive a Capacity Supply Obligation, since these are the resources that were displaced by the OOM resources. As a result, ISO-NE notes that this higher Alternative Capacity Price does not send an accurate signal about the need for new capacity."[264]

The Alternative Capacity Pricing rule was a balance between competing objectives. The several attractions included that the rule would not prevent OOM resources from making their own offers and clearing in the market. The rule would only affects the mitigation of offers in determining the alternative price that would apply to existing resources that otherwise would clear in the market.[265] In equilibrium, with perfect mitigation, the Alternative Capacity Pricing rule would tend to produce competitive offers and the market-clearing price would be the same as the alternative price. With less than perfect mitigation, however, the rule could produce two prices and result in procuring some capacity in excess of the capacity requirement.

The FERC ultimately rejected the ISO New England Alternative Capacity Pricing rule and directed ISO New England to provide a MOPR based on an approved mitigation model. "…[W]e will require ISO-NE to work with its stakeholders to develop an offer-floor mitigation construct akin to those in PJM and NYISO." [266] In New England the mitigation plan is to have resources specific mitigated offers without

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264 ISO New England, 135 FERC ¶ 61,029 at ¶ 92-93. Issued April 13, 2011.
265 W. Hogan, Comments on PJM Minimum Offer Price Rule, FERC Technical Conference, August 25, 2011. (http://www.hks.harvard.edu/fs/whogan/Hogan_Statement_2011-08-25.pdf.)
266 ISO New England, 135 FERC ¶ 61,029 at ¶ 19. Issued April 13, 2011.

any exemptions. How well this will work on further review is open to question. The current compliance filing deadline for implementing the revised MOPR is December 13, 2012.[267]

267 Andrew Gillespie, "FCM Compliance and Conforming Changes," ISO New England, June 13, 2012. http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2012/jun12132012/a17_iso_presentation_06_13_12.ppt.

IV. Differences in Auction Timing, Obligation Patterns, etc. Across NY, PJM and ISO New England

This section discusses issues arising from differences in capacity market timing across the PJM-New York- New England region. It also addresses locational factors impacting the portability of capacity.

A. Market Timing Differences

Both PJM and ISO New England clear their capacity markets on an annual basis (i.e. the procurement period is a year) using capacity years whose start and end dates differ from the New York ISO capability periods (June through May for PJM and ISO New England and May through October and November through April for the New York ISO). If the New York ISO procured capacity on an annual basis, these differences in procurement period start dates would make it more difficult to shift capacity between New York and PJM or New England. While the New York ISO clears capacity market auctions covering the six month periods corresponding to its capability periods (called strip auctions), participation in these auctions is voluntary and a great deal of capacity is purchased and sold in the monthly auction (which is also a voluntary auction), and finally in the spot auction which is the only mandatory auction and procures capacity for a month long period. Hence, a supplier that has sold capacity in PJM for a capability year ending in May would not be able to sell its capacity in the New York ISO summer strip auction or the May monthly or spot auctions but it would be able to participate in the New York ISO monthly and spot auctions for the balance of the year after May when its obligation in the PJM market would have ended.

Conversely, a supplier that has historically sold its capacity into New York but wishes to shift to selling capacity into PJM or ISO New England could sell its capacity in the New York monthly or spot auctions through May of the year, then shift its capacity to PJM or ISO New England for the next year starting in

June. Hence, no monthly auction revenues need to be forgone when shifting capacity in either direction between the regions.

Hence, New York's monthly auction design provides flexibility for capacity suppliers to shift their resources across the three regions in response to local surpluses or shortages.

While differences in capacity year definitions do not impede shifting capacity between New York, or PJM or New England, the difference between the forward procurement in PJM and New England and current year procurement in New York can delay adjustments to unexpected conditions. Capacity exports from New York in response to unexpectedly low prices in New York will be delayed by the forward procurement designs in PJM and New England. Similarly, imports into New York or reductions in exports in response to higher than expected capacity prices in New York will also be delayed by the forward procurement designs in PJM and New England.

If market participant expectations are incorrect, New York capacity sold into PJM or New England could displace demand response or new generation, reducing the supply of capacity available to New York capacity buyers in the future year. In addition, excess capacity could clear in PJM on its demand curve for future years and not be available for sale in the New York capacity market during the operating year. Similarly, capacity could clear in ISO New England, increasing the surplus capacity at the price floor. This excess capacity that clears in PJM or ISO New England future year capacity markets would be physically available to meet New York load to the extent it was not needed in PJM or New England. However, it does not appear to us that PJM and New England have any obligation to activate their demand response in order to make exports available to New York, so generation that clears in the other capacity markets may reduce the generation supply available to New York in real time.

Another timing related factor that can reduce the ability of generation owners in PJM or New England to shift capacity into New York in response to expected higher prices is that market power mitigation policies in PJM or New England may require that existing capacity be offered at low prices in the PJM and ISO New England forward capacity auctions, precluding its availability to be subsequently offered in the New York capacity market auction.

For example, PJM rules would allow capacity to be withheld from the PJM forward capacity auction in order to be sold into New York in two ways. First, capacity can be withheld from the PJM forward RPM auction to support exports to another region by showing that the resource has a "financially and physically firm commitment to an external sale of its capacity."[268] This standard would not allow a capacity resource to be withheld from the PJM RPM market in order to be subsequently offered into a New York ISO strip, monthly or spot auction, but would allow the resource's capacity be sold forward on a bilateral basis to a load serving entity in New York. Second, the rules also allow a resource to use the "documented opportunity costs" of capacity in an adjacent market as the basis for its offer in the RPM auction and if the offer did not clear, the capacity would be available for export.[269]

It is not clear how the opportunity costs of selling and a future New York auction could be documented to the satisfaction of the market monitor several years in advance.

Hence, it may in practice be necessary to enter into a forward contract with a New York load serving entity in order for PJM capacity resources to hold capacity out of the base residual auctions in order to subsequently sell the capacity into New York. Some kind of restrictions are necessary to avoid the potential for entities possessing market power in some region in PJM to circumvent the mitigation rules by withholding capacity from the base residual auction in order to offer it for sale in a subsequent New

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268 Attachment DD section 6.6 (g).
269 Monitoring Analytics, 2011 State of the Market Report for PJM, March 15, 2012, p. 101.

York ISO auction. However, the PJM design in which all suppliers, no matter how small are subjected to seller offer price mitigation, creates an unnecessary barrier to inter RTO capacity transactions.

B. Capacity Exports and Transmission Constraints

This portability of capacity across the Eastern ISO regions is not hypothetical. Substantial amounts of capacity have been sold into ISO New England's forward capacity market in recent FCA auctions with delivery beginning in the summer of 2012.

In recent New York capacity market auctions the clearing price of NYCA capacity has been far below the floor price of capacity in ISO New England's FCA auction and as a result, New York generation resources have apparently been selling as much capacity into ISO New England's forward capacity auctions as ISO New England will allow.

In the ISO New England 2011 and 2012 forward capacity market auctions, exports of capacity from New York to New England rose to the level at which they were constrained by ISO New England's 1100 megawatt limit on imports from New York.[270] Table 38 shows the quantity of capacity imports into New England over the New York interface, and the amount supported by New York generation (as opposed to capacity in Hydro-Quebec wheeled through New York).

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270 See ISO New England, Forward Capacity Auction Results Filing, in Docket ER11-3891-000 at p. 7. Submitted June 27 2011 and ISO-NE, Forward Capacity Auction Results Filing, in Docket ER12-1678-000 at p. 7. Submitted April 30, 2012.

Table 38
ISO New England Forward Capacity Cleared from New York

Auction	Auction Year	Operation Year	Import Capacity Cleared From the NY Interface	Portion From NY Resource*
FCA 2	2008	2011-2012	1,244	813
FCA 3	2009	2012-2013	921	801
FCA 4	2010	2013-2014	949	829
FCA 5	2011	2014-2015	1,110	819
FCA 6	2012	2015-2016	1,100	816

Source: http://www.iso-ne.com/markets/othrmkts_data/fcm/cal_results/index.html

* Excludes the following from HQ Control Area: 55 MW in FCA 2, 120 MW in FCA 3, 120 MW in FCA 4, 291 MW in FCA 5 and 284 MW in FCA 6.

* Excludes the following from BEMI Ontario Assets: 375 MW in FCA 2.

* Values presented are those which cleared in June of the relevant auction.

The New York capacity offered at the floor price in the ISO New England FCA auctions would be subject to additional proration based on the overall excess capacity offered at the floor price. Even with proration however, roughly on the order of 700 megawatts of New York capacity, potentially capacity located west of Central East, cleared in the ISO New England capacity market.

In view of the large quantity of New York generating capacity that has cleared in the ISO New England forward capacity market for both the current and coming years, it is important from a New York reliability standpoint that the New York ISO's evaluation of New York Control Area reliability account for any impact of these exports on the transfer capability to meet New York Control Area load. One concern would be if the New York ISO were obligated to use the New York transmission system to deliver power from ISO New England capacity resources located in Western New York to ISO New England in circumstances in which the transfer capability on Central East and other cross state transmission limits was needed to meet New York control area load.

It is our understanding that the New York ISO is not obligated to deliver power from Western New York resources to New England if this would violate cross state transmission constraints and the New York

ISO is reserve short east of Central East but not reserve short for the NYCA as a whole. Since Central East would likely be constrained or nearly constrained at any time that New York is in a reserve shortage situation that would cause it to curtail exports to New England, ISO New England may be purchasing Western New York capacity that likely would not be deliverable in the circumstances that the designation as ISO New England capacity would be relevant, i.e. when the New York ISO is recalling exports supported by New York capacity.

Given our understanding of the rules applicable to capacity sales from New York into New England, capacity sales into New England by New York resources located west of Central East do not appear to create any reliability risks for New York firm load as exports of power to New England from capacity resources located in Western New York would not be scheduled if this would violate cross state transmission limits or require the New York ISO to shed firm load when New York had adequate capacity resources to meet its load. Under the current New York ISO capacity market design, however, capacity located east of Central East in the NYCA capacity zone receives the same low capacity prices as capacity in the West so it is possible that if no new Lower Hudson Valley or east of Central East zone were introduced in the New York ISO capacity market, future capacity exports to ISO New England could be sourced from resources east of Central East. If this turned out to be the case, the New York ISO could end up short of capacity east of Central East in these years. This could cause reliability problems if there was insufficient capacity in Zone J to compensate and could cause a substantial increase in the local capacity requirement and price in Zone J and possibly Zone K.

Given the large amount of excess capacity that cleared in the ISO New England forward capacity market through 2016, it appears somewhat unlikely that ISO New England would actually need to call upon its capacity resources located in New York to meet New England load as a result of inadequate capacity in

New England,[271] unless either the New England economy strengthens materially and load rises above current projections or there is substantial non-performance by other resources clearing the New England capacity market for those years. However, if Western New York capacity market prices remain low, there is a potential for future sales of capacity into New England that might be needed, and called upon, to meet ISO New England reliability if load rises in New England or other capacity shuts down.

PJM models imported New York capacity as deliverable into the (PJM) RTO region.[272] This obligation would be satisfied by power delivered into Western PJM so deliverability should not be a barrier to the export of capacity from New York to PJM and should not have adverse impacts on the ability of the New York ISO to meet New York control area load under the current capacity market design because the export of capacity to PJM would not impact transmission constraints likely to impact the ability of the New York ISO to meet NYCA load.

C. Capacity Transaction Scheduling Requirements

Another inter-regional capacity portability issue is the potential cost shifting associated with efforts by ISO New England and some New England regulators to use the New England capacity market design to allow New England to carry additional operating reserves in New York with the cost of carrying these operating reserves borne by New York transmission customers.

ISO New England takes a different approach to the availability of import supply from capacity resources than does the New York ISO. Rather than requiring that resources submit bids to make the capacity available when they are told by the ISO that their capacity is needed, ISO New England requires that the

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271 While New England may not need to call upon this capacity located in New York as a result of a lack of installed capacity to meet New England load, there is a potential for New England to use this capacity to provide spinning reserves for new England at the expense of New York ISO transmission customers or as a substitute for a reliability commitment. These issues are discussed below.

272 PJM, Manual 18: PJM Capacity Market Revision 15. June 28, 2012, p.27

capacity resources submit bids in every hour of every day for all capacity that is not out due to an outage.[273] ISO New England does not require that the import offers submitted in the New England market be low enough to always clear, but they must be submitted at a price that is equal to or below either the New York ISO day-ahead market price at the interface or lower than a price based on a 22,000 btu/kwh heat rate generator.[274]

In order for capacity transactions from New York to New England to flow if called upon, New York capacity suppliers selling capacity into New England would have to submit export bids in the New York ISO scheduling process that would clear in every hour for all of the capacity they have agreed to export to ISO New England, yet this capacity would rarely flow. If the New York ISO did not derate these transactions after a few hours when they did not flow, it would solve RTC to an artificially high level of load (including exports) in every hour, leading to the commitment of excess generation or scheduling of excess imports from other regions, depressing real-time prices and inflating real-time uplift costs borne by New York transmission customers. If the New York ISO were to apply its current derating policies, these transactions would be derated every day after they failed to flow in the initial hours of the day.

Back in 2007-2009, when some New York generators sold capacity into New England, they avoided having their transactions derated by submitting low priced export bids from New York and offered imports into New England at high prices, with the stated intent of modifying the offer prices if ISO New England notified them that their capacity was needed. ISO New England has subsequently modified its requirements, however, requiring that capacity resources offer imports into New England at prices that ISO New England might take from time to time. It is not clear how capacity resources located in New York that have sold substantial amounts of capacity into New England will handle these obligations and

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273 ISO New England, Transmission, Markets & Services Tariff, Sections III.12.6.1.2.1
274 ISO New England, Transmission, Markets & Services Tariff, Section III.12.6.1.2.1 (a) and (b)

what impact their actions might have on the New York market and the costs borne by its transmission customers.

If these capacity suppliers bid for exports from New York in every hour but their offers only occasionally clear in New England, New York would be providing New England with additional operating reserves with the cost borne by New York transmission customers who would pay the costs of resources committed into RTC to support the exports which failed to flow in real time.

These inconsistencies could be addressed in a fairly straight-forward manner when CTS scheduling is implemented between New England and New York, however, it is not clear when CTS scheduling will be implemented, and it is also possible that New York suppliers have sold substantial capacity into New England for years prior to 2014.

V. Evaluation of a Forward Capacity Market Design in New York

In this final section we evaluate whether the existing regulatory requirement, resource planning processes, and capacity market construct in New York provide adequate notice for the NYISO's reliability planning obligations and evaluate the desirability of introducing a forward capacity market in New York with a three to five year reserve adequacy reliability criterion.

A. Forward Reliability Assessment in New York

The New York ISO's capacity requirement is enforced for load serving entities one month at a time in the monthly spot auction. While market participants can and do enter into forward bilateral capacity market contracts,[275] and can participate in the forward strip and monthly capacity market auctions coordinated by the New York ISO, load serving entities have no obligation to secure capacity prior to the spot market auction.

Given the long-lead time required to construct generation, the supply side response to an impending shortfall in capacity to meet the capacity target in the monthly spot auction is limited to additional demand response, possibly additional import supply, or the possible reactivation of mothballed generating capacity. The NYISO has an bi-annual backstop reliability evaluation process, that is part of the Comprehensive System Planning Process. This process looks forward 10 years to evaluate capacity adequacy on a projected basis over a time frame in which investment in incremental generation is feasible. The first step in this evaluation process is the preparation of the Reliability Needs Assessment.[276] If this assessment identifies unmet reliability needs over the 10-year study period, the

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275 These bilateral contracts include forward contracts for Zone J and rest of state capacity traded and cleared on NYMEX (product symbols NRS and NNC) that settle as contracts for differences against the spot auction price.

276 See, for example, the 2010 Reliability Needs Assessment, Final report, September 2010.

New York ISO will designate one or more transmission owners to develop “regulated backstop” solutions to the reliability needs and will also request market based solutions and alternative regulated solutions from any interested party to address these needs. The final step in this process is the issuance of the Comprehensive Reliability Plan for that period, which includes any determination of actions necessary to ensure system reliability, whether market based or regulated backstop in nature.

The New York ISO Comprehensive System Planning Process has some limitations in providing a forward evaluation of electric system reliability in comparison to a forward capacity procurement process such as those employed by PJM and ISO New England. These limitations include 1) the evaluation of whether internal generation will be shut down or mothballed is based on NYISO expectations and may not be accurate because generators assumed to remain in operation have no financial commitment to remain in operation over the horizon of the study;[277] 2) the evaluation of import supply is based on supply that has been available in the past, which may or may not be the case in the future; 3) the evaluation of the level of capacity exports is based on the current level, which could increase or decrease in the future; 4) the evaluation of demand response is based on expected supply given current conditions, which may or may not accurately forecast future demand response; and 5) resources assumed to be coming on line in future years may be delayed or may not come in service at all.

While all of these uncertainties exist in the supply analysis underlying the New York ISO Comprehensive System Planning Process, there is an underlying logic from a reliability perspective in that in general resources assumed to be available in the planning study, could be available, if the price of capacity were sufficiently high. The process for evaluating future reliability needs, however, does not provide a forward price to signal whether it would be economic to develop new capacity to replace capacity that may only be available at very high prices in the future, as might be the case, for example, due to the cost of

277 Conversely, a resource that is anticipated to retire may remain in service if capacity market prices rise sufficiently.

complying with environmental regulations. Load serving entities and resource developers can have a general sense of the cost of environmental compliance for the various resources at risk of retirement, but the range of uncertainty based on publicly available information may not permit an accurate evaluation of potential future capacity market prices in the time frame during which new replacement capacity would need to be developed.

A further potential limitation of the New York ISO's reliability needs assessment is that it is necessarily based on a forward projection of peak load, which may or may not be accurate. This limitation is important, but is shared by the New York process and the forward capacity markets of PJM and ISO New England. In practice it is very difficult to project future peak demand several years in advance. The difficulty of projecting electricity demand three or more years in advance has been seen in the New York Comprehensive Reliability Planning Process. The New York reliability process projected a capacity shortfall in the 2007 Reliability Needs Assessment and triggered the initial steps of the backstop procurement process; in retrospect it is clear that the 2007 analysis was based on peak load forecasts for future years that proved to greatly exceed actual peak demand.[278]

The 2008 Reliability Needs Assessment similarly identified reliability needs beginning in 2012,[279] based on a forecast of peak load plus losses of 35430 megawatts in 2011 and 35,882 megawatts in 2012.[280] These load projections turned out to be far in excess of actual or forecasted peak loads for those years. Indeed, the 2009 Reliability Needs Assessment was based on projected 2018 NYCA load that was 1973 megawatts less than the 2008 Reliability Needs Assessment projection for 2017.[281]

278 See New York Independent Service Operator, 2007 Reliability Needs Assessment, March 16, 2007 pp. 8, 10-11, 14-17, and Letter to NYISO Transmission Owners and other Customers and Interested Parties, April 1, 2008 from Henry Chao on behalf of the New York ISO.

279 See New York Independent Service Operator, 2008 Reliability Needs Assessment, Final Report, December 10, 2007 pp. I-17 to I-21

280 Ibid p. III-3

281 See, New York Independent Service Operator, 2009 Reliability Needs Assessment, Final Report, January 13, 2009, p.iii.

B. Advantages and Disadvantages of Forward Capacity Markets

Forward capacity procurement processes such as those in PJM and New England lock in most supply several years in advance, thus avoiding some of the uncertainty regarding generation shut-down decisions, capacity import availability, and capacity exports that complicate the New York ISO's forward evaluations of resource adequacy.

With the three year forward commitment by suppliers provided by their forward capacity markets, PJM and ISO New England have greater insight into the intentions of their generation owners regarding the continued operation of their generation as generation owners must decide whether or not to commit their generating resources in the PJM and ISO New England capacity markets three or so years in advance of the operating year. This is particularly helpful when there is a potential for market conditions, including environmental regulations, to cause the shutdown of substantial amounts of capacity within a relatively short-term frame. Moreover, the auction provides a forward price signal of the cost of environmental compliance which can guide the development of additional resources.

However, it must be kept in mind that the forward auction only clarifies the intentions of generation owners three years in advance. It will not resolve uncertainties such as those regarding future government environmental policies that might impact the ability or costs for existing generation to remain in operation. If government environmental regulations are more restrictive than expected by the affected generation owners, capacity that clears in the forward capacity market may not be available to operate and conversely, if environmental restrictions are looser than projected or delayed, capacity that did not clear in the forward auction may be available in the operating year.

Hence, there can be a potential for differences under a forward capacity market design between the quantity of capacity that clears in the forward auction and the amount that is available to meet load during the operating year. These gaps will be smaller if there are reconfiguration auctions in which new resources can buy out of their capacity supply obligation and if the capacity supply obligation is financial rather than physical, but the unexpected shutdown of a resource can produce a shortfall of capacity under a forward capacity market design just as under a current year capacity market design.

Another potential role that has been suggested for a forward capacity market is to identify in a forward timeframe in which replacement capacity or transmission upgrades can be put in service, potential retirements of specific facilities whose operation is needed to maintain local reliability. In our view, a generic forward capacity market is poorly suited to serve this role. While a forward capacity market can contract in aggregate for the capacity needed to reliably meet load, contracting for an aggregate amount of capacity in this auction does not ensure that specific resources will remain in operation to meet local reliability requirements. This is because individual resources can buy out of their forward capacity obligations in sequential reconfiguration or "incremental" auctions and be contractually free to exit the market with a short-time frame.

This is an appropriate and desirable feature of a forward capacity market design because it allows resources seeking to participant in the capacity market to manage the risks associated with uncertain environmental permitting and construction timelines. This feature is common to the PJM and ISO New England forward capacity markets as discussed above. Moreover, we observed above in Section IIIE that large amounts of capacity have bought out of their forward supply obligation in PJM's incremental auctions and that smaller amounts have bought out of their forward obligation in ISO New England's forward capacity market. Hence, the fact that a specific resource sold capacity in a forward capacity auction does not preclude that resource from ceasing operation during the capacity year without financial penalty and doing so on short notice after buying out of their capacity market obligation.[282]

Concerns regarding the continued operation of "at risk" generating resources that are needed for local reliability are better addressed through forward contracts entered into by the relevant transmission owner that specifically address those local reliability requirements. A rolling three or four year forward contract with generation resources need to meet local reliability requirements would provide forward notification of retirements, and would also address the kind of local market power concerns that were the focus in Docket ER10-2220-000.

Indeed, precisely these kind of forward contracts to provide local reliability were entered into covering some of the generation divested by New York transmission owners in 1998-1999, but subsequently not extended. If such contracts were entered into and either extended from year to year, or the need for them eliminated through transmission upgrades if the contracts became too expensive, these problems would be addressed, without the need for a forward capacity market covering all of the generation and demand response in New York.[283]

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282 While it could be expensive for a resource needed for local reliability to buy out of its forward capacity market obligation in the incremental auction if the capacity market had tightened in the interim, it will not necessarily be the case that the exit of resources needed for local reliability will be associated with a tight capacity market. Rather, it is more likely they will be associated with a slack capacity market with excess capacity and low capacity prices in which the cost of buying out of the forward obligation will be low. Prices in the PJM and ISO New England incremental auctions have typically been quite low, to the extent that they might even incent resources that intend to exit to participate in the forward auction than buy out of the obligation in the incremental auctions.

283 If new entrants clearing capacity in the forward market are required to post little collateral to ensure their performance, new entrants could sell capacity in the forward capacity then buy out of the obligation at a profit if capacity prices fall in subsequent reconfiguration auctions and default if capacity prices rise. This type of behavior can be discouraged through appropriate collateral requirements but those requirements can raise the cost of entry and hence raise the capacity price paid to new and existing resources. This concern with the effect of high collateral requirements motivated ISO New England and its market participants to choose a design based more on intensive monitoring to ensure performance but that approach can be resource intensive for the ISO and hence expensive for market participants and conflicts with the efficiency concept of resources being able to exit their obligation if capacity that was expected to be uneconomic and shut down remains in operation.

Our view appears to be consistent with the view of the staff of the New York Department of Public Service, who observed that "when the New York Transmission Owners divested most of their generation, certain contractual restrictions were included to address local reliability and market power issues. Similarly, when local reliability issues have required the deferment of proposed retirements, those issues have been addressed via contracts negotiated between the local transmission owners and the supplier. DPS Staff suggests that similar contract-based approaches may provide a more effective means of addressing local reliability and market power issues than a NYISO-based forward capacity market. Contracts with Transmission Owners could also be tailored to supplement the NYISO and Transmission Owner planning processes. Such contracts would be designed not to replace the ICAP market, but to address other specific issues which cannot yet be resolved by the energy, ancillary services or capacity markets."[284]

If such a process were conducted on a forward basis, providing compensation to generation needed to maintain local reliability in exchange for a contractual obligation to operate, it is anticipated that this approach would be far lower cost than the implementation of a forward capacity market and would avoid the potential problems with would arise if a forward capacity market were used to address local reliability issues.

There would be checks and balances in such a market based approach as generators will to provide assurance of continued operation to provide local reliability services would receive additional revenues reflecting this value, while the use of rolling multi-year forward contracts would avoid hold up problems, as the term of the forward contract would enable transmission owners to contract in advance for transmission upgrades needed to replace generation no longer willing to provide these local reliability services at a satisfactory price. The outcome if such an approach were used would be that generators

284 Staff of the New York State Department of Public Service Comments on draft FTI report, p. 6.

willing to provide such assurance of continued operation would receive additional payments that would reduce their going forward costs.

We also recommend that if such an approach were implemented, the payments for local reliability services would be accounted for as a market payment in applying buyer side mitigation as long as the payment was offered both to existing and new generation.

When there is substantial uncertainty regarding future government policies impacting the economic viability or physical operating capability of existing generation, the quality of the forward capacity price signal provided by forward auctions will potentially depend on the financial assurance policies regarding existing capacity of the ISO or RTO coordinating the forward auction, and on the financial integrity of the entities owning at-risk generation. The capacity price required for resources facing uncertain future staying-in-business costs to commit to physical performance may be very high, particularly for a one year capacity contract. A forward procurement of capacity that requires physical performance may cause these resources to submit high offer prices that effectively remove these resources from the auction, replaced in the clearing supply by demand response or other generation resources. To the extent that the forward capacity procurement is financial, on the other hand, resources with such uncertain future costs may be willing to offer supply in the forward procurement auction at lower prices than would otherwise be the case, because they will have the option of buying out of the obligation in subsequent auctions if their cost of remaining in business rises excessively. At a minimum, a forward procurement can make such high staying-in-business costs visible in a time frame in which lower cost alternatives can be placed in service.[285]

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285 There can still be surprises regarding resource exit in the forward auction, but those surprises will occur in a time frame in which replacement resources have only incurred the costs needed to participate in the forward auction, they would not need to guess which existing resources might or might not shut down in deciding whether or not to go forward with the construction of their resource.

A forward auction would also provide greater visibility to market participants in general, and generation developers, in particular regarding future imports and exports of capacity. For example, it does not appear that the New York ISO 2010 Resource Needs Assessment took into account the potential for substantial amounts of New York generation to be sold into the ISO New England capacity market. With the New York ISO's current year-by-year or capability period by capability period auction design, future year capacity export commitments of generation located in New York will be directly visible only through the auction reports of PJM and ISO New England.

This lack of direct visibility and interaction between these future year export commitments and the New York ISO capacity market will not necessarily lead to adverse reliability or market impacts because New York generation owners will not sell their capacity forward into New England if they expect that they will be able to earn much larger returns by selling that capacity in the New York ISO auctions in future years.[286] However, because the PJM and ISO New England markets will have contracted for capacity in advance of the New York ISO markets, if demand in the region of the Eastern ISOs grows more than expected or there are unexpected reductions in supply, the burden could fall on the New York ISO capacity market which is contracting for capacity on a short-term basis. Since the New York capacity market is cleared both after the forward procurement auctions and after most of the reconfiguration auctions conducted by PJM and ISO New England, there is a potential for mistaken assessments to cause capacity shortages to fall more on the New York capacity market when the future operating year arrives.[287] This is analogous to the situation the California ISO has been in, with its power consumers contracting for capacity on a short-term basis while most other load serving entities in the West are contracting for capacity a few years in advance. California ISO customers thereby benefit from low prices

286 The market impact of these capacity sales would also likely be reflected in the forward capacity prices on NYMEX, although the limited forward duration of the reported prices, the impact on exchange traded capacity prices would only become apparent a year or so prior to the operating year.

287 Conversely, low demand growth could mean that New York consumers purchase capacity at much lower prices than the capacity was sold forward into New England and even higher demand could simply keep some additional Western New York in operation and restore Western capacity prices to more normal levels, without leading to any adverse reliability consequences.

when the market is weak, but they are exposed to very high prices and shortages when there is a shortage of supply, as they will be the ones bearing the shortage.

The New York capacity market design is fundamentally different than the situation in California in 2000 because New York capacity prices can rise to high levels if there was a shortage, unlike the situation in California in which load serving entities both did not contract forward and then were constrained by price caps from out bidding load serving entities outside California for scarce power. The potential for these kind of situations is a reason to better align the capacity market demand curve with the reliability value of incremental capacity so that the New York ISO will be able to attract needed capacity despite contracting after PJM and ISO New England. Going after PJM and ISO New England in the contracting process does mean however that New York consumers could be paying high spot prices for all capacity not purchased through forward bilateral contracts if such a regional shortage were to develop. The potential for a regional capacity shortage is not a concern at present with large capacity excesses in New York and New England but is a possibility in the long-run.

It needs to be kept in mind that forward contracting for capacity shifts risk from capacity suppliers to consumers. This has been particularly apparent in the PJM capacity market which contracted forward for capacity based on load growth forecasts that proved materially inaccurate following the financial crisis, with the cost of keeping the excess capacity in service, or of buying back the capacity obligation at a lower price in an incremental auction, borne by PJM power consumers. An intrinsic feature of an ISO coordinated forward capacity market is that capacity is procured based on an administratively determined load forecast, rather than a market based evaluation.

Because a forward capacity market would be cleared based on demand projected several years in advance, rather than demand projected six months or a year in advance, capacity prices in a forward capacity market will tend to be more stable than under a current year procurement design, as they will not vary in response to short-term variations in economic conditions that raise or depress the projected peak load for the current year (but would not have been projected three years in advance).

Hence, PJM's capacity prices were likely more stable than New York's over the 2009-2010 through 2012/2013 capacity years, in part because the PJM capacity market for these years cleared before the downturn in power demand that followed the collapse of the housing bubble. However, the forward auction design is likely responsible for only part of the difference in the stability of capacity prices over this period. It is also relevant that a far larger proportion of the PJM generating capacity will likely need to either shut down completely or incur substantial costs to remain in operation in compliance with current and expected environmental regulation than is the case in the New York ISO, or New England. It is likely that the decision to shut-down some of this generation, (and/or the offering of this capacity at capacity prices in the Base Residual Auction reflecting the expected cost of keeping the capacity in operation under new or anticipated environmental rules) accounts in part for the stability of prices in the PJM capacity auctions, which have remained at higher levels than those in Western New York or New England.

One of the concerns with the PJM and ISO New England forward capacity markets when they were implemented was whether the forward procurement process would disadvantage demand response relative to generation, because demand response providers would have to contract several years forward with power consumers. In practice, both regions have experienced a substantial increase in the role of demand response within their forward capacity market designs. This increase is likely due to the much higher capacity prices,[288] rather than to the forward procurement, but the forward procurement process has not precluded this increased role of demand response.

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288 In both regions some of the demand response is supplied in response to utility or state programs that pay even higher prices for demand response than auction clearing prices.

On the other hand, while PJM and ISO New England experience to date shows that demand response can be accommodated within a forward capacity market, the higher costs to both market participants and the ISO of implementing demand response in a forward capacity market needs to be considered in evaluating the benefits of implementing a forward capacity market in New York.

While forward capacity procurement designs may make the likely future availability of physical generation assets clearer for market participants, regulators and the ISO, they may contribute to increased uncertainty regarding actual demand response performance. While, as noted above, the forward auction designs of both PJM and ISO New England have elicited substantial participation by demand response providers, there is some uncertainty regarding whether this increased demand reduction capability will actually be provided when those future years arrive. This uncertainty arises both from the fact that the performance of the demand response resources will not be observed until the operating year arrives and from the fact that recent low load levels relative to projections and available capacity have reduced the need to call upon demand response (particularly in New England), so the performance of even existing resources is somewhat uncertain because it has not been demonstrated in practice.

This is really no different, however, from the uncertainty that exists in a year to year capacity market, as the amount of physical capacity built will be based on expected future demand response supply, which is not known until the operating year arrives.

What is different is the need to measure demand response, and energy efficiency, performance against a more uncertain baseline and the complexity of doing so. A forward capacity market procures capacity to meet projected future demand and capacity market demand response would need to be able to offer reductions relative to that projected future demand in order to avoid excess procurement of generating capacity, but the amount of demand reduction available in those future years may depend on how much demand actually grows. If load does not grow as much as forecasted because of poor economic conditions, a demand response provider may not be able to reduce consumption relative to a projected baseline demand that may not exist because the production line, is not even operating because of those poor economic conditions. Hence it is necessary to address situations in which neither the demand reductions nor the need for those demand reductions exists because of changes in economic conditions. If reconfiguration auctions are run in which the ISO adjusts its projected future demand downward when load growth fails to materialize, demand response providers will have a mechanism to buy out of their commitments to provide demand response when low demand growth makes it impossible, or uneconomic, to provide the amount of demand response sold in the forward auction.

Similarly, when demand reductions due to energy efficiency are bid into a forward capacity market relative to a projected baseline demand several years in the future, it is necessary to distinguish lower demand due to energy efficiency investments from lower demand due to poor economic conditions.

A second concern with forward capacity markets is a potential tendency for forward demand forecasts to average out higher than actual weather adjusted load or near-term load forecasts because of extra conservatism built into forward load forecasts.

The initial forward demand projections of PJM and ISO New England have turned out to be quite a bit higher than actual peak load. Table 39 shows that as the Base Residual auctions have been conducted further and further in advance of the operating year, the peak load forecast has exceeded the weather normalized peak load by a larger and larger amount.[289]

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289 The data in Table 39 for the Zonal Peak load Forecast and the weather normalized coincident peak loads are both taken from the PJM reports on the Base Residual Auction Planning Parameters which contain this information by LDA. The peak load forecast appears in the report for the auction year, while the weather normalized actual data is included in the report for a subsequent year after the delivery year has occurred. Because the data is broken down by LDA, we have been able to adjust the forecast and weather normalize load totals to include the same LDA in each year, although some LDAs are not included in either total to maintain this consistency.

Table 39
PJM Forecast and Actual Peak Loads

Capacity Year	Year Auction was Conducted	Preliminary Zonal Peak Load Forecast Used for RPM Base Residual Auction [A]	Actual Weather Normalized Coincident Peak Loads* [B]	Actual PJM Summer Coincident Peak Load* [C]
2007/2008	2007	137,421	136,427	139,428
2008/2009	2007	139,806	136,550	130,100
2009/2010	2007	142,177	133,780	126,798
2010/2011	2008	144,592	135,080	136,460
2011/2012	2008	142,390	131,325	144,063
2012/2013	2009	144,857	-	-
2013/2014	2010	147,270	-	-
2014/2015	2011	145,404	-	-
2015/2016	2012	144,222	-	-

* Refers to only the first of the two years listed.

Notes:

1. All figures exclude ATSI and DEOK for consistency.
2. [A] and [B] include FRR load data.
3. [D] Based on the Capacity Market; includes MAAC, EMAAC and SWMAAC.
4. Data used in [A] and [B] for 2011-2012 does not include DCLO which was not incldued in BRA auction load forecast.

Souces:

1. [A] and [B]: RPM Base Residual Auction Planning Parameters (http://pjm.com/markets-and-operations/rpm/rpm-auction-user-info.aspx#Item03)
2. [C] and [D]: PJM State of the Market Reports
3. 2011/2012 DLCO figure from [A] added in based on http://pjm.com/markets-and-operations/rpm/~/media/markets-ops/rpm/rpm-auction-info/dqe-daily-frr-ucap-obligation-for-2011-2012.ashx
4. 2007 DLCO figure from [B] added in based on estimated of 2900 on page 32 of http://pjm.com/~/media/documents/reports/2012-pjm-load-report.ashx

Weather normalized peak load data for ISO New England the 2011-2012 capacity year indicate a weather normalized and demand response adjusted peak load of 29,533 megawatts, compared to the procurement target of 31,525 megawatts, a nearly 2000 megawatt difference.[290]

Table 40 below portrays the load forecasts for the FCA auctions to date and the actual peak loads for the historical years. The actual peak loads are not directly comparable to forecasts because they are not

290 David Ehrlich, ISO New England, "ISO New England RSP12 Kong-run Forecast of Energy and Seasonal Peaks," February 15, 2012 p. 7

weather normalized and do not account for the impact of peak load reductions due to energy efficiency investments or demand response, which need to be added to the observed peak load.

Table 40
ISO New England Forecast and Actual Peak Loads

Auction	Year of Auction	Capacity Commitment Period	Forecast Source	Peak Load Forecast	Actual Summer Peak Load
FCA1	2008	2010-2011	2007 CELT Report	31035	27102
FCA2	2008	2011-2012	2008 CELT Report	31525	27707
FCA3	2009	2012-2013	2009 CELT Report	31075	-
FCA4	2010	2013-2014	2010 CELT Report	30840	-
FCA5	2011	2014-2015	2011 CELT Report	31250	-
FCA6	2012	2015-2016	2011 CELT Report	31705	-

Notes
(1) FCA 2 took place in December of 2008; it was assumed that the 2008 CELT report projection was used as this was the most recent projection available at the time of the auction. The CELT Report used for forecasts was confirmed in ISO NE FERC acution results filings for all other years.
(2) Actual Peak Load corresponds to the peak load in the summer of the first year of the Capacity Commitment Period.

Sources
(1) Peak Load Forecasts are taken from Table 1.6 of the CELT Report indicated, which can be found at: http://www.iso-ne.com/trans/celt/report/index.html
(2) Actual Peak Load data is taken from Table 1.5 of the CELT Report.

This pattern of overstated load forecasts in forward auctions to date does not necessarily reflect a consistent bias, it could simply reflect to coincidence of those initial year's corresponding to the recession following the financial crisis. However, if the planning models used to generate peak load forecasts for a forward capacity market are not well grounded in probabilities, rather than possibilities, they would tend to have a systematic bias towards overstating future capacity requirements.

Such a bias toward high load forecasts could be accommodated by designs in which developers or demand response providers could bid in high cost resources that would not move in to development unless load appeared to be following the high load growth projections and buy out their obligations in future reconfiguration auctions after the peak load forecast has been reduced. Indeed, energy efficiency investments in particular might be amenable to being used to offset excessive load forecasts, even if no investment in energy efficiency is made. The potential profitability of this kind of strategy could make approaches that seek to carefully track the progress of new capacity resources and makes sure they are on track, more expensive to implement if energy efficiency investments are included in a forward capacity market.

Insight into the level of the costs needed to make sure that energy efficiency impacts reflect real programs rather than load forecast error and to ensure that demand response capability is available could be provided by data on the number of staff ISO New England uses to monitor the development of new resources. We lack the insight into ISO New England staffing to make any such an assessment.

Finally, there is nothing in the current New York ISO capacity market design that precludes capacity suppliers and load serving entities from entering into long-term forward contracts for capacity and indeed, some load serving entities, such as the Long island Power Authority, have done so. While default providers with short-term obligations to serve have reasons not to enter into long-term capacity contracts, there is no barrier to competitive retailers entering into longer-term contracts with both their customers and with capacity suppliers, to the extent that this reduces risks and costs, (as would presumably be the case if it reflected the long-run interests of their customers).

A forward capacity procurement process conducted by an ISO based on its planning forecasts of future demand implements a policy that the ISO contract forward for an aggregate amount of capacity that individual consumers and load serving entities have made the decision not to contract forward for. While there are theories that raise potential concerns about the adequacy of the forward contracting incentives of retail consumers and load serving entities, the implementation of a forward capacity market is not the only way to address these concerns, if and when a determination is made that some action is needed.

If these kind of incentives issues in the New York retail access design are identified and motivate a decision to implement a forward capacity market, the evaluation of the need for such a forward procurement process should include assessment of whether changes in the retail access design would also address these problems. It is relevant in this regard that the New York ISO is a single state ISO, so unlike in PJM and ISO New England, there is a single state government that has the ability to address such incentive problems, if this is the issue.[291]

C. Evaluation of a Forward Capacity Market for the New York ISO

There are both advantages and disadvantages to the New York electricity market and its participants of moving to a forward capacity procurement design. First, as discussed above, a forward procurement process would provide greater visibility to the cost of keeping existing generation in operation. This greater visibility would be particularly beneficial if New York capacity resources were impacted by environmental regulations that would potentially be prohibitively expensive for some resources to comply with in order to remain in the market and those compliance costs were not clearly visible to the market as a whole. Hence, in this kind of environment the greater visibility of entry and exit decisions provided by a forward procurement process would likely reduce the variability of future capacity prices because generation retirement decisions would be more visible in a time frame in which it could be replaced with lower cost new capacity and could also enable future capacity needs to be met with a lower cost resource mix, by identifying capacity with a high cost to remain in operation in a time frame in which it could be replaced by lower cost capacity. This increased visibility will be more beneficial to resources that would be able to come on-line within the time frame of the forward procurement auction, relative to capacity resources (including demand response) with shorter development and construction cycles. How material the benefits of this greater visibility would be depend in part on the degree to which existing New York generators will be impacted by regulatory changes which materially increase their costs of continued operation and the degree to which those increased costs are not readily apparent to the rest of the industry.

291 Another issue, recognized in a recent initiative in New England, is that a commitment to a longer term forward generation capacity commitment raises the complication of formalizing the coordination of transmission reliability planning. ISO New England, “Aligning Markets and Planning,” ISO Discussion Paper, June 13, 2012 http://www.iso-ne.com/committees/comm_wkgrps/strategic_planning_discussion/materials/mra_discussion_paper_06132012_vtransmit.pdf. The possible impact of a forward capacity market on the New York ISO’s transmission planning process is outside the scope of this report.

It is particularly unclear whether there would be material long-run benefits to this greater visibility since the time frame in which a forward capacity market could be implemented in the New York ISO is likely past the time frame in which most current uncertainties regarding generation operation, such as coal fired unit operation and the continued operation of the Indian Point nuclear facilities, would have been resolved. Moreover, the uncertainties associated with continued Indian Point operation would be much better addressed through a resolution in which if a shutdown is to occur, the date is set sufficiently far in the future that there is adequate time for new capacity resources and transmission to come into service, than by implementation of a forward capacity market.

First, some kinds of resources have longer lead times for development and construction than others, requiring that the development and construction of some resources begin further in advance of the operating year. These longer lead times do not mean that these kinds of resources are not built under the current year-by-year capacity market design and require a forward capacity market to support their construction. The longer lead times just means that their construction must be based on expected load, expected generation retirements, expected fuel prices and expected capacity prices.

Second, a forward capacity procurement process would tend to somewhat stabilize capacity prices, which could reduce the cost of capital for capacity projects, reducing their market price and the cost of the capacity needed to maintain New York reliability. This stabilization, however, would come about through an involuntary shifting of risk from capacity suppliers to New York power consumers, so there would be no net benefit from this change in the cost of capital; it would simply reflect the change in who was bearing risk.

Third, there is a potential for a forward capacity procurement process to be more conservative in projecting future demand and in contracting for capacity than is the market under the current system.

This could potentially result in a systematic increase in the amount of capacity procured relative to actual peak loads and lead to an increase in capacity costs to New York power consumers. This outcome can presumably be avoided in the design/implementation of a forward capacity procurement process,[292] but remains a risk.

Fourth, there is also a potential for a forward capacity procurement process to be so rigid in imposing performance obligations on existing resources that clear in the auction, but have future operating risks due to the uncertainties associated with future government regulations and compliance costs, that capacity prematurely exits the market in response to these kinds of uncertain future costs. Such an outcome could also presumably be avoided through care in the design but is a potential risk associated with lengthening the time frame of a mandatory procurement process.[293]

Fifth, the longer time period with a forward capacity procurement design between the point in time at which the capacity price is fixed and remaining-in-business costs are incurred, would increase the regulatory risk associated with unfavorable changes in costs, relative to New York's current capacity market design. If this change in risk appears substantial, this perception could result in an increase in capacity offer prices and a reduction in capacity supply relative to the current design.

Sixth, a forward capacity procurement design might require that the NYISO shift to an annual procurement process in its mandatory forward auction, as do ISO New England and PJM. This would potentially have a few negative consequences. First, such a change would eliminate the flexibility in

292 One way to do this would be to contract forward for capacity based on an expected load forecast that is not the highest possible load forecast and to contract for additional capacity in subsequent years if it appears that load is rising more rapidly than projected. Obviously the later auctions would be skewed towards contracting for resources available in a shorter time frame, but this is also the case in the current design if the one year in advance load forecast is higher than what developers projected 4 years prior.

293 It is important to understand that these risks are associated with a mandatory forward procurement process. In a voluntary forward contracting process, the specific resources facing these kinds of uncertainties would refrain from entering into forward contracts while resources not facing such material risks could choose to do so and prices would reflect expectations about the likely impact of such changes.

accommodating shifts of resources between New York and the capacity markets of PJM and ISO New England that is currently provided by New York's monthly spot auction. Second, such a change might make it more difficult for Hydro-Quebec to supply capacity to New York for the summer months. These negatives could perhaps be avoided by adopting a more flexible forward capacity market design than used by PJM or ISO New England that allowed some degree of monthly variation but this flexibility might be unworkable in a forward auction. Clearing a forward auction independently one month at a time would introduce inefficiencies because the cost of resource being available in one month would depend on whether it was taken in another month. This would be analogous to the inefficiencies from clearing a day-ahead market separately hour by hour. Hence, it might be too complex to implement a forward auction that preserves the flexibility of the current New York design.

Seventh, a shift to a forward procurement design would entail one time transition costs for the New York ISO and its market participants. In addition, while it is not intrinsically more expensive to coordinate a forward capacity auction and then a current year or capability period capacity auction, some of the complexities that need to be addressed in a forward auction have the potential to raise the ongoing cost of administering the overall capacity market. In particular, the uncertainties associated with demand response in a forward auction, the need to account for future energy efficiency investments, the potential for demand response and energy efficiency offers to be used to arbitrage the ISO load forecast, and the need to ensure performance by physical generation resources, both new and existing, all will need to be addressed in some manner, and are likely to raise the ongoing administration costs for such a forward procurement relative to the current design. We cannot quantify those costs without knowing how market participants, the New York ISO and other stakeholders would choose to resolve these complexities, but we think it is clear that the direction of the effect would be to increase the ongoing costs.

Finally, the current market design does not prevent load serving entities from contracting forward for capacity. A forward capacity procurement process conducted by an ISO based on its planning forecasts of future demand implements a policy that the ISO contract forward for capacity that individual consumers and load serving entities have made the decision not to contract forward for. While there are theories that raise potential concerns about the adequacy of the forward contracting incentives of retail consumers and load serving entities[294], the implementation of a forward capacity market is not the only way to address these concerns, if and when a determination is made that some action is needed. Hence, a decision to incur the considerable costs of implementing and then operating a forward capacity market in order to address such incentive problems should be made with due consideration of the results of an overall evaluation of the retail access design in New York, presumably by the New York Public Service Commission. This evaluation could include an assessment of whether the current retail access design is leading to an inefficiently low level of forward hedging by consumers in New York with respect to either energy prices, capacity prices or both. If such a problem is identified, this evaluation could consider whether the incentive problems would be best addressed by the New York ISO contracting forward for capacity on behalf of consumers or through changes in the retail access design.

While guidance on how to address many of these issues could eventually be drawn from the experience of PJM and ISO New England in implementing their forward markets, both regions are currently still exploring how to best resolve these and other issues.

Our comments regarding the benefits, costs and risks of implementing a forward capacity market in New York have focused on the attributes of a multi-year forward auction in which capacity is contracted for three or more years prior to the operating year. Another possible design change would be to transition from a design in which there are forward voluntary capability period auctions and mandatory monthly spot auctions to a design with a mandatory forward annual or capability period procurement. Such a

294 Such as the likely inability of providers of last resort to recover the cost of long-term capacity contracts from rate payers.

design would reduce the significance of most of the potential costs and risks of a multi-year forward capacity market but would also reduce the potential benefits.

Some of the issues discussed above with respect to a multi-year forward procurement that would be avoided entirely or materially less significant in the context of a annual forward procurement would be 1) the potential for increased capacity costs due to reliance on multi-year forward load forecasts would be largely eliminated as a one year forward capacity market could be based on essentially the same load forecasts as the current design, 2) the potential for pre-mature exit or higher supply offers due to greater uncertainty about future staying in business costs, particularly those associated with environmental regulations, would also be greatly reduced because of the nearer term time frame for the auction; 3) It should be possible to maintain a two capability period procurement design in a one year forward process without introducing undue complexity; and 4) the transition costs should be lower, perhaps materially so, for a one year forward auction relative to a multi-year forward auction as many of the complications that need to be addressed in a multi-year forward auction would be less of a concern in a one year forward auction, requiring fewer changes in the current design.

D. Review of Other Potentially Beneficial PJM and ISO New England Capacity Market Design Features

Aside from the forward procurement design feature, other beneficial features of the PJM and ISO New England capacity markets that might enhance the New York ISO’s capacity market design are 1) PJM’s effort to define capacity zones well before the time that they actually bind so that they can be enforced when needed; and 2) PJM’s effort to provide improved performance incentives by basing capacity payments on availability during peak load hours.

As the New York ISO moves to implement additional capacity market zones, it should imitate the PJM approach of attempting to anticipate potentially binding constraints and model then in the New York ISO auctions before it is a certainty that they will actually bind.

The New York ISO's capacity market performance incentives for thermal generation are currently based upon the resource's UCAP rating, which reflects a resource's forced outage rate over all hours of the year.[295] Paying generators for capacity based on their UCAP rating rewards generation that is most likely to be available when needed during shortage conditions if generator availability depends largely on forced outages, which are random and not correlated across units. It also provides appropriate incentives to the extent that the incidence and length of forced outages is largely outside the control of the generator.

However, these premises are not necessarily valid in contemporary power markets. Non-availability of gas fired generation due to high gas prices or gas interruption will be correlated across gas fired generators on cold winter days as New England has found. The New York ISO has historically had sufficient dual fueled capacity that winter gas availability constraints has not resulted in reliability problems; however with the retirement of substantial amounts of dual fueled generating capacity in the New York ISO control area, this may cease to be the case at some point in the future[296]At some point in coming years, it may be necessary to maintaining New York reliability during winter conditions for gas fired generators to take measures to ensure that they can be available on a cold winter day, either through maintaining duel fuel capability or contracting for firm gas pipeline capacity.

PJM and New England's forward capacity markets have rules that more narrowly focus generator capacity value on generator availability during high load conditions than does a general UCAP rule.

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295 See New York Independent Service Operator, Installed Capacity Manual Version 6.2. January 2012, Section 4.5.. Other rules apply to limited control run of river resources, demand side resources and intermittent resources..

296 This could happen as dual fueled capacity in New York shuts down and could be accelerated if capacity located in New York that is either dual fueled or does not burn gas is sold into the ISO New England capacity market and not recallable to meet New York load on a cold winter day in the future.

However, while these RTOs availability rules are an improvement over a UCAP system neither RTO's rules provide strong incentives for resources to be available during stressed system conditions, as seen by both the PJM and ISO New England's internal Market Monitors comments regarding gas fired generator performance cited in Section IIIF above.

Hence, while it is desirable that the New York ISO provide stronger performance incentives for New York suppliers during stressed system conditions in the future, we think a better approach for the New York ISO than to mimic either the PJM or ISO New England capacity availability rules would be to shift capacity market revenues into energy market prices during shortage conditions. The New York ISO does not need all of its capacity to be available during the winter peak but it needs to have enough capacity available to meet load when gas prices spike and gas availability may be curtailed. Appropriate reserve shortage prices would contribute to resources making the investments necessary to be available.

A common feature of the New England and PJM capacity market designs that we do not recommend that the New York ISO imitate is the inclusion of energy efficiency programs in the capacity market, i.e. extending its current capacity market to include capacity payments for permanent reductions in load.

There are several reasons for this view. First, within New York's current capacity market design, reductions in peak load attributable to energy efficiency investments would be reflected in a reduction in customer capacity market obligations with a one year lag. That is, the peak load forecast used to develop the 2012 installed capacity requirement would be based on 2011 load data. Hence, energy efficiency investments that reduced the 2011 peak load, would immediately provide a benefit by reducing the capacity procurement obligation for the next year, 2012.

The New York ISO standard for demand response participating in the capacity market (SCR) is that the demand response resource must be able to reduce demand under peak load conditions. Continuing reductions from what load would have otherwise been such as those potentially produced by energy efficiency investments are already incorporated in the ISO load forecast and provide no reliability benefit in real-time operation as the reductions are incorporated in both capacity and unit commitment decisions. Because energy efficiency investments are not dispatchable, they would be difficult for the New York ISO to distinguish from load forecast error or random load variations if applied on a year by year basis to the power consumption of individual customers or groups of customers.

Second, including permanent reductions in peak demand in a capacity market program requires that peak demand be grossed up to reflect to compensate. While it would not be particularly complicated for the New York ISO to make such an adjustment in its capacity market to add past cleared demand reductions back into peak load, as do ISO New England[297] and PJM,[298] similar adjustments would need to be made not just within the New York ISO capacity market but throughout the entire process of allocating capacity costs to retail consumers to avoid unintended cost shifts. We have not identified any benefit to introducing such complexity.

If the New York ISO were to shift to a forward, rather than current year or capability period, capacity auction, there would be a longer interval between the time that a permanent reduction in peak load would be observed and then reflected in the amount of capacity procured. If the New York ISO were to shift to a design in which capacity was procured several years prior to the operating year, there might be a need to implement a process by which consumers could commit to such future reductions in peak load, the New York ISO's procurement of future capacity would be reduced to reflect those reductions and the consumers allocated capacity costs based on their actual peak load reflecting the committed reductions. As discussed above, however, implementing such a process in a forward procurement process is not

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297 Energy Efficiency Forecast Working Group of the ISO New England Staff, "Draft Final Energy-Efficiency Forecast" p. 57 at http://www.iso-ne.com/committees/comm_wkgrps/othr/enrgy_effncy_frcst/frcst/2012/draft_final_ee_forecast_3_16_12.pdf

298 PJM Forward Market Operations, "Energy Efficiency Measurement & Verification", p.6, found at (http://pjm.com/~/media/documents/manuals/m18b.ashx).

straightforward and would involve many design choices because of the potential for the offer of energy efficiency load reductions to be a mechanism for profiting from errors in the ISO load forecast. We do not recommend any particular design for accommodating energy efficiency load reductions as a product sold in a forward capacity procurement process because of the many potentially complex choices that would need to be mandated, because we do not identify a compelling need for the New York ISO to implement a forward capacity market, and because the details of how to account for permanent reductions in load within such a capacity market could be addressed at the time such a forward capacity market was developed.[299]

In the discussion of energy efficiency investments in the capacity market stakeholder meeting on July 31, it was suggested that another reason to explicitly account for the impact of energy efficiency investments on peak load might be that the ISO's estimate of the demand reduction is less than the impact bid in by the market participant. We do not perceive any benefit for paying for an overstated amount of demand reduction, which would simply shift capacity costs to other power consumers. In addition, there would only be a transitory impact from such overstatement in any case if the ISO were adding back into peak load the same amount of permanent load reduction that was bid in. The potential for the ISO to either over estimate or under estimate the impact of particular energy efficiency investments needs to be evaluated in the context of the potential for energy efficiency investments to be used to arbitrage the ISOs load forecast, which in our view will potentially make addressing these issues in a forward capacity market quite complex.

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299 Another issue to be considered in such a process would be how to account for permanent reductions in demand that were funded by New York Public Service Commission programs or NYSERDA rather than the consumer. It might be more appropriate for the New York ISO to simply model those reductions in peak load based on

Table 41
Additional Summer Capability from New Generation by Zone (MW)

2000												
	A	B	C	D	E	F	G	H	I	J	K	NYCA
Total	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2001												
	A	B	C	D	E	F	G	H	I	J	K	NYCA
Total	0.0	6.6	0.0	0.0	11.0	0.0	0.0	0.0	0.0	0.0	0.0	17.6
Wind	0.0	6.6	0.0	0.0	11.0	0.0	0.0	0.0	0.0	0.0	0.0	17.6
2002												
	A	B	C	D	E	F	G	H	I	J	K	NYCA
Total	5.3	0.0	72.6	0.0	0.0	0.0	0.0	0.0	0.0	586.7	47.0	711.6
Gas Turbine	0.0	0.0	42.6	0.0	0.0	0.0	0.0	0.0	0.0	411.6	47.0	501.2
Steam Turbine	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	175.1	0.0	175.1
Wind	0.0	0.0	30.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	30.0
2003												
	A	B	C	D	E	F	G	H	I	J	K	NYCA
Total	37.3	0.0	0.0	0.0	1.3	0.0	0.0	0.0	0.0	0.0	507.4	546.0
Gas Turbine	37.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	507.4	544.7
Hydro	0.0	0.0	0.0	0.0	1.3	0.0	0.0	0.0	0.0	0.0	0.0	1.3
2004												
	A	B	C	D	E	F	G	H	I	J	K	NYCA
Total	0.0	0.0	3.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	102.5	105.5
Gas Turbine	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	102.5	102.5
Internal Combustion	0.0	0.0	3.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.0
2005												
	A	B	C	D	E	F	G	H	I	J	K	NYCA
Total	0.0	0.0	0.0	0.0	0.0	939.7	0.0	0.0	0.0	222.0	97.5	1259.2
Combined Cycle	0.0	0.0	0.0	0.0	0.0	938.4	0.0	0.0	0.0	222.0	0.0	1160.4
Gas Turbine	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	97.5	97.5
Hydro	0.0	0.0	0.0	0.0	0.0	1.3	0.0	0.0	0.0	0.0	0.0	1.3
2006												
	A	B	C	D	E	F	G	H	I	J	K	NYCA
Total	0.0	0.0	0.0	0.0	198.0	727.2	0.0	0.0	0.0	767.9	157.9	1851.0
Combined Cycle	0.0	0.0	0.0	0.0	0.0	727.2	0.0	0.0	0.0	767.9	157.9	1653.0
Wind	0.0	0.0	0.0	0.0	198.0	0.0	0.0	0.0	0.0	0.0	0.0	198.0
2007												
	A	B	C	D	E	F	G	H	I	J	K	NYCA
Total	2.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	530.9	0.0	532.9
2007												
Combined Cycle	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	530.9	0.0	530.9
Wind	2.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.0

2008												
	A	B	C	D	E	F	G	H	I	J	K	NYCA
Total	4.7	4.7	2.1	0.0	12.5	0.0	0.0	0.0	0.0	0.0	0.0	24.0
Internal Combustion	4.7	4.7	2.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	11.5
Wind	0.0	0.0	0.0	0.0	12.5	0.0	0.0	0.0	0.0	0.0	0.0	12.5
2009												
	A	B	C	D	E	F	G	H	I	J	K	NYCA
Total	0.0	4.1	0.0	24.5	4.1	0.0	0.0	0.0	0.0	0.0	0.0	32.7
Internal Combustion	0.0	4.1	0.0	4.6	4.1	0.0	0.0	0.0	0.0	0.0	0.0	12.8
Wind	0.0	0.0	0.0	19.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	19.9
2010												
	A	B	C	D	E	F	G	H	I	J	K	NYCA
Total	6.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	309.6	316.0
Combined Cycle	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	309.6	309.6
Internal Combustion	6.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6.4
2011												
	A	B	C	D	E	F	G	H	I	J	K	NYCA
Total	0.0	0.0	0.0	0.0	7.4	571.2	0.0	0.0	0.0	0.0	0.0	578.6
Combined Cycle	0.0	0.0	0.0	0.0	0.0	571.2	0.0	0.0	0.0	0.0	0.0	571.2
Wind	0.0	0.0	0.0	0.0	7.4	0.0	0.0	0.0	0.0	0.0	0.0	7.4
2012												
	A	B	C	D	E	F	G	H	I	J	K	NYCA
Total	0.0	0.0	51.3	0.0	0.0	0.0	0.0	0.0	0.0	549.2	31.5	632.0
Combined Cycle	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	549.2	0.0	549.2
PV Solar	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	31.5	31.5
Wind	0.0	0.0	51.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	51.3
Total:	55.7	15.4	129.0	24.5	234.3	2238.1	0.0	0.0	0.0	2656.7	1253.4	6607.1

Notes

(1) The totals given above are total generation added since the previous Gold Book; this does not always correspond to the calendar year. For 2000-2004, the Gold Book is current as of January 1 of that year; the 2004 table reports generation added during the 2003 calendar year. For 2005-2012, the gold book is current as of April 1; the 2011 table reports generation added between April 2010 and March 2011.

(2) Three of the generators that make up the total additions for Zone F in 2005 are originally listed in the 2004 GB as going online in Dec 03. In all subsequent Gold Books, they are listed as going online in May 2004, so they have been presented in the 2005 table (to reflect additions between April 2004 and March 2005) and omitted from 2004 Zone F additions.

(3) Some components of the 2001 and 2002 totals (6.6 MW in Zone B and 30 MW in Zone C, respectively) were not listed in the Gold Book for their respective year but were listed as going online during this year in a later Gold Book. For these units, 2006 capability is given.

Sources

Data from 2000-2005 was taken from Table III-2 of the relevant Gold Book. Data from 2006-2012 was taken from an Excel Spreadsheet of Table III-2,published by the NYISO at:
http://www.nyiso.com/public/markets_operations/services/planning/documents/index.jsp

Table 42
NYISO ICAP Prices ($/kW – Month), May 2003 –April 2012

Capability			**Spot Price**			**Monthly Price**			**Strip Price**		
Period	**Year**	**Month**	**NYC**	**LI**	**ROS**	**NYC**	**LI**	**ROS**	**NYC**	**LI**	**ROS**
Summer 2003	2003	5	12.36	23	0.25	10	24	1.3	11.22	9.41	1.67
	2003	6	11.46	5.17	2.34	13.78		1.06	11.22	9.41	1.67
	2003	7	11.46	5.14	2.28	11.57	5	2.01	11.22	9.41	1.67
	2003	8	11.46	4.03	2.25	11.56	5	2.04	11.22	9.41	1.67
	2003	9	11.46	4.55	2.08	11.56		1.97	11.22	9.41	1.67
	2003	10	11.45	4.55	2.01	11.55		1.93	11.22	9.41	1.67
Winter 2003/2004	2003	11	6.98	8.14	1.94	6.67		1.15	6.55	4	1.17
	2003	12	6.98	8.22	1.79	6.64		1.48	6.55	4	1.17
	2004	1	6.98	7.99	1.75	6.64		1.5	6.55	4	1.17
	2004	2	6.98	7.08	1.73	6.77	7.5	1.58	6.55	4	1.17
	2004	3	6.98	7.72	1	6.05	7	1.54	6.55	4	1.17
	2004	4	6.98	7.04	0.8	6	6.85	0.99	6.55	4	1.17
Summer 2004	2004	5	11.42	9.83	1.31	11.16	8	1.65	11.15	8	1.68
	2004	6	11.42	9.79	1.27	11.29	9.29	1.48	11.15	8	1.68
	2004	7	11.42	8.42	1.04	11.29	8.67	1.29	11.15	8	1.68
	2004	8	11.42	8.16	1.17	11.25	8.05	1.15	11.15	8	1.68
	2004	9	11.42	8.15	1.07	11.25	8.06	1.16	11.15	8	1.68
	2004	10	11.42	8.15	1.12	11.21	8.06	1.18	11.15	8	1.68
Winter 2004/2005	2004	11	7.12	6.34	0.7	6.96	4	0.7	6.68	4	0.6
	2004	12	7.12	6.21	0.61	7.07	4.33	0.69	6.68	4	0.6
	2005	1	7.12	6.16	0.27	7.03	3.81	0.59	6.68	4	0.6
	2005	2	7.12	6.14	0.25	7.03	3.68	0.49	6.68	4	0.6
	2005	3	7.12	6.16	0.41	7.03	3.54	0.45	6.68	4	0.6
	2005	4	7.12	6.23	0.27	7.03	3.54	0.48	6.68	4	0.6
Summer 2005	2005	5	12.03	12.15	2	11.86	8	0.75	11.68	8	0.75
	2005	6	11.96	11.96	1.96	11.8	8.5	1.4	11.68	8	0.75
	2005	7	11.95	10.48	1	11.82	9	1.29	11.68	8	0.75
	2005	8	11.86	10.06	1	11.82	8.5	0.81	11.68	8	0.75
	2005	9	11.7	9.9	1.45	11.82	8.61	0.81	11.68	8	0.75
	2005	10	11.86	9.49	1.25	11.82	8.71	1.03	11.68	8	0.75
Winter 2005/2006	2005	11	6.55	8.37	0.85	6.39	5	0.67	5.11	0.68	0.62
	2005	12	6.55	8.16	0.65	6.44	4.99	0.68	5.11	0.68	0.62
	2006	1	6.55	9	2.01	6.21	5	0.63	5.11	0.68	0.62
	2006	2	6.55	8.18	1.67	5.78	5	1.01	5.11	0.68	0.62
	2006	3	6.55	8.07	0.57	5.78	5	0.58	5.11	0.68	0.62

Capability			Spot Price			Monthly Price			Strip Price		
Period	Year	Month	NYC	LI	ROS	NYC	LI	ROS	NYC	LI	ROS
Winter 2005/2006	2006	4	6.55	8.14	0.4	5.88	5	0.51	5.11	0.68	0.62
Summer 2006	2006	5	12.71	11.15	3.25	12.37	6.5	1.65	12.35	6.5	1.44
	2006	6	12.71	6.76	3.12	12.44	7.5	2.49	12.35	6.5	1.44
	2006	7	12.71	6.52	3.33	12.48	7	2.9	12.35	6.5	1.44
	2006	8	12.71	6.31	3	12.57	6.75	3.26	12.35	6.5	1.44
	2006	9	12.71	6.19	2.8	12.62	6.5	2.99	12.35	6.5	1.44
	2006	10	12.71	6.02	2.77	12.7	6	2.75	12.35	6.5	1.44
Winter 2006/2007	2006	11	5.84	3.66	1.5	5.79	3.74	2	5.67	3.5	2.5
	2006	12	5.84	3.65	2.18	5.79	3.5	2.17	5.67	3.5	2.5
	2007	1	5.84	3.6	2.71	5.82	3.5	2.24	5.67	3.5	2.5
	2007	2	5.84	3.61	2.67	5.82	3.5	2.43	5.67	3.5	2.5
	2007	3	5.84	3.61	1.34	5.84	3.5	1.73	5.67	3.5	2.5
	2007	4	5.84	3.61	1.1	5.84	3.3	1.3	5.67	3.5	2.5
Summer 2007	2007	5	12.72	7.25	3.16	12.28	3.75	2.27	12.37	3.75	2.25
	2007	6	12.72	8.78	3.39	12.37	5.5	2.76	12.37	3.75	2.25
	2007	7	12.72	7.23	3.52	12.37		2.97	12.37	3.75	2.25
	2007	8	12.72	7.22	3.43	12.37	5.5	3.14	12.37	3.75	2.25
	2007	9	12.72	7.17	3.14	12.37	5.5	3.14	12.37	3.75	2.25
	2007	10	12.72	7.17	3.03	12.37	5.5	3	12.37	3.75	2.25
Winter 2007/2008	2007	11	5.77	4.31	1.6	5.1	3.5	1.9	5.32	1.91	1.91
	2007	12	5.77	4.27	2.22	5.41		1.92	5.32		1.91
	2008	1	5.77	4.2	3.4	5.42	3.7	2.33	5.32		1.91
	2008	2	5.77	4.07	3.18	4.55	3	2.49	5.32		1.91
	2008	3	1.05	4.02	1.05	3.39	2.1	1.46	5.32		1.91
	2008	4	0.75	4.01	0.75	1.05	2.1	1.05	5.32		1.91
Summer 2008	2008	5	5.53	2.6	2.6	6.5	2.78	2.79	6.5		2.67
	2008	6	6.03	2.94	2.94	5.37	2.81	2.86	6.5		2.67
	2008	7	6.33	2.8	2.8	6.03	2.95	2.96	6.5		2.67
	2008	8	6.17	2.7	2.7	6.29	2.89	2.87	6.5		2.67
	2008	9	5.98	2.45	2.45	5.97	2.67	2.69	6.5		2.67
	2008	10	5.83	1.93	1.93	5.91	2.4	2.4	6.5		2.67
Winter 2008/2009	2008	11	1.52	1	1	2.19	1.99	1.64	2.79	1.77	1.77
	2008	12	1.25	1.25	1.25	1.67	1.55	1.41	2.79	1.77	1.77
	2009	1	3.19	3.19	3.19	1.46	1.44	1.43	2.79	1.77	1.77
	2009	2	1.77	1.77	1.77	2.75	2.5	2.22	2.79	1.77	1.77
	2009	3	0.5	0.5	0.5	1.48	0.98	1.04	2.79	1.77	1.77

Capability			Spot Price			Monthly Price			Strip Price		
Period	**Year**	**Month**	**NYC**	**LI**	**ROS**	**NYC**	**LI**	**ROS**	**NYC**	**LI**	**ROS**
Winter 2008/2009	2009	4	0.3	0.3	0.3	0.75	0.5	0.5	2.79	1.77	1.77
Summer 2009	2009	5	8.72	4.71	2.61	6.94	3.02	3.03	6.75	3.01	3.01
	2009	6	8.65	4.65	4.22	8.55	3.44	3.42	6.75	3.01	3.01
	2009	7	8.47	4.77	4.42	8.67	4.11	4	6.75	3.01	3.01
	2009	8	8.45	3.42	3.42	8.46	4.19	4.15	6.75	3.01	3.01
	2009	9	7.65	2.76	2.76	8.33	3.44	3.46	6.75	3.01	3.01
	2009	10	7.7	2.23	2.23	7.62	2.59	2.59	6.75	3.01	3.01
Winter 2009/2010	2009	11	1.23	0.5	0.5	2.44	1.82	1.64	4.65	1.75	1.75
	2009	12	0.76	0.75	0.75	4.27	2.08	1.4	4.65	1.75	1.75
	2010	1	1.85	1.85	1.85	4.38	1.62	1.66	4.65	1.75	1.75
	2010	2	7.98	3.49	3.49	6.27	2.37	2.24	4.65	1.75	1.75
	2010	3	7.72	0.85	0.85	7.4	1.59	1.47	4.65	1.75	1.75
	2010	4	7.16	0.64	0.64	7.5	0.74	0.74	4.65	1.75	1.75
Summer 2010	2010	5	13.53	5.81	3.52	13.01	2.7	2.54	12.9	2.47	2.47
	2010	6	13.13	2.12	2.12	13.33	2.68	2.51	12.9	2.47	2.47
	2010	7	13.05	1.91	1.91	12.98	1.9	1.9	12.9	2.47	2.47
	2010	8	12.97	1.68	1.68	12.94	1.79	1.63	12.9	2.47	2.47
	2010	9	12.5	0.63	0.63	12.84	1	0.97	12.9	2.47	2.47
	2010	10	12.72	0.56	0.48	12.45	0.45	0.45	12.9	2.47	2.47
Winter 2010/2011	2010	11	4.29	0.01	0.01	4.75	0.27	0.27	4.6	0.39	0.39
	2010	12	3.66	0.5	0.5	4.28	0.1	0.1	4.6	0.39	0.39
	2011	1	3.99	0.5	0.5	3.66	0.65	0.65	4.6	0.39	0.39
	2011	2	3.57	0.65	0.65	4.25	0.45	0.45	4.6	0.39	0.39
	2011	3	3.57	0.3	0.3	4	0.15	0.15	4.6	0.39	0.39
	2011	4	3.32	0.15	0.15	3.82	0.2	0.2	4.6	0.39	0.39
Summer 2011	2011	5	11.97	0.65	0.65	13.2	0.6	0.6	13.54	0.55	0.55
	2011	6	11.76	0.55	0.55	12	0.6	0.6	13.54	0.55	0.55
	2011	7	5.76	0.15	0.15	11.84	0.5	0.5	13.54	0.55	0.55
	2011	8	5.83	0.05	0.05	9.5	0.16	0.16	13.54	0.55	0.55
	2011	9	5.71	0.2	0.18	6.99	0.1	0.1	13.54	0.55	0.55
	2011	10	9.01	0.13	0.13	6.49	0.1	0.1	13.54	0.55	0.55
Winter 2011/2012	2011	11	0.5	0.06	0.06	3	0.12	0.12	2.7	0.15	0.15
	2011	12	4.68	0.1	0.1	2	0.1	0.1	2.7	0.15	0.15
	2012	1	4.91	0.5	0.5	4	0.15	0.15	2.7	0.15	0.15
	2012	2	4.87	0.18	0.18	4.8	0.4	0.4	2.7	0.15	0.15
	2012	3	4.7	0.1	0.1	4.3	0.08	0.08	2.7	0.15	0.15

Capability			Spot Price			Monthly Price			Strip Price		
Period	**Year**	**Month**	**NYC**	**LI**	**ROS**	**NYC**	**LI**	**ROS**	**NYC**	**LI**	**ROS**
Winter 2011/2012	2012	4	4.61	0.1	0.1	4.45	0.1	0.1	2.7	0.15	0.15
Summer 2012	2012	5	17.16	2.91	2.91	12.3	1.28	1.28	11.7	1.42	1.25
	2012	6	11.54	1.94	1.94	15.65	2.14	2.14	11.7	1.42	1.25
	2012	7	10.95	3.56	1.98	11.85	1.45	1.45	11.7	1.42	1.25
	2012	8	10.64	3.56	1.9	11.39	3	2.01	11.7	1.42	1.25
	2012	9	10.47	3.59	2.4	10.74	3.5	2.28	11.7	1.42	1.25
Mean			**7.98**	**4.58**	**1.63**	**8.04**	**3.76**	**1.55**	**8.09**	**3.50**	**1.51**

Table 43
Imports into NYISO (MW)

Capability Period	Month	Spot Auction				Strip Auction				Monthly Auction				Total			
		HQ	IESO	NE	PJM	HQ	IESO	NE	PJM	HQ	IESO	NE	PJM	HQ	IESO	NE	PJM
Summer 2006	May-06	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Jun-06	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Jul-06	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Aug-06	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Sep-06	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Oct-06	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Winter 2006-2007	Nov-06	190.0	0.0	0.0	0.0	33.7	0.0	0.0	0.0	129.6	0.0	40.1	0.0	353.3	0.0	40.1	0.0
	Dec-06	0.0	0.0	0.0	0.0	33.7	0.0	0.0	0.0	66.3	0.0	0.0	0.0	100.0	0.0	0.0	0.0
	Jan-07	200.3	0.0	0.0	0.0	33.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	234.0	0.0	0.0	0.0
	Feb-07	0.0	0.0	0.0	0.0	33.7	0.0	0.0	0.0	123.3	0.0	0.0	0.0	157.0	0.0	0.0	0.0
	Mar-07	6.0	0.0	0.0	0.0	33.7	0.0	0.0	0.0	0.2	0.0	0.0	0.0	39.9	0.0	0.0	0.0
	Apr-07	16.3	0.0	0.0	0.0	33.7	0.0	0.0	0.0	249.0	0.0	0.0	0.0	299.0	0.0	0.0	0.0
Summer 2007	May-07	41.5	0.0	0.0	0.0	30.0	0.0	0.0	0.0	58.5	0.0	0.0	0.0	130.0	0.0	0.0	0.0
	Jun-07	0.0	0.0	0.0	0.0	30.0	0.0	0.0	0.0	100.0	0.0	0.0	0.0	130.0	0.0	0.0	0.0
	Jul-07	0.0	0.0	0.0	0.0	30.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	30.0	0.0	0.0	0.0
	Aug-07	0.0	0.0	0.0	0.0	30.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	30.0	0.0	0.0	0.0
	Sep-07	0.0	0.0	0.0	0.0	30.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	30.0	0.0	0.0	0.0
	Oct-07	0.0	0.0	0.0	0.0	30.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	30.0	0.0	0.0	0.0
Winter 2007-2008	Nov-07	353.5	0.0	0.0	0.0	14.0	0.0	0.0	0.0	410.5	0.0	0.0	0.0	778.0	0.0	0.0	0.0
	Dec-07	110.0	0.0	0.0	0.0	14.0	0.0	0.0	0.0	150.0	0.0	0.0	0.0	274.0	0.0	0.0	0.0
	Jan-08	0.0	0.0	0.0	0.0	14.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	14.0	0.0	0.0	0.0
	Feb-08	0.0	0.0	0.0	0.0	14.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	14.0	0.0	0.0	0.0
	Mar-08	1.0	0.0	0.0	0.0	14.0	0.0	0.0	0.0	600.0	0.0	0.0	0.0	615.0	0.0	0.0	0.0
	Apr-08	51.0	0.0	0.0	0.0	14.0	0.0	0.0	0.0	50.0	0.0	0.0	0.0	115.0	0.0	0.0	0.0
Summer 2008	May-08	0.0	0.0	0.0	0.0	85.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	85.0	0.0	0.0	0.0
	Jun-08	0.0	0.0	0.0	0.0	85.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	85.0	0.0	0.0	0.0
	Jul-08	0.0	0.0	0.0	0.0	85.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	85.0	0.0	0.0	0.0
	Aug-08	0.0	0.0	0.0	0.0	85.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	85.0	0.0	0.0	0.0
	Sep-08	0.0	0.0	0.0	0.0	85.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	85.0	0.0	0.0	0.0
	Oct-08	0.0	0.0	0.0	0.0	85.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	85.0	0.0	0.0	0.0
Winter 2008-2009	Nov-08	150.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	300.0	0.0	0.0	0.0	450.0	0.0	0.0	0.0
	Dec-08	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Jan-09	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Feb-09	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Mar-09	249.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	249.6	0.0	0.0	0.0
	Apr-09	151.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	151.6	0.0	0.0	0.0
Summer 2009	May-09	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Jun-09	85.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.0	0.0	0.0	0.0	90.0	0.0	0.0	0.0
	Jul-09	25.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	100.0	0.0	0.0	0.0	125.0	0.0	0.0	0.0
	Aug-09	25.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	50.0	0.0	0.0	0.0	75.0	0.0	0.0	0.0
	Sep-09	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10.9	0.0	0.0	0.0	10.9
	Oct-09	25.0	0.0	0.0	200.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	100.0	25.0	0.0	0.0	300.0
Winter 2009-2010	Nov-09	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	669.1	0.0	0.0	0.0	669.1	0.0	0.0	0.0
	Dec-09	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	141.0	0.0	0.0	0.0	141.0	0.0	0.0	0.0
	Jan-10	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Feb-10	100.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	100.0	0.0	0.0	0.0
	Mar-10	170.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	781.0	0.0	0.0	0.0	951.0	0.0	0.0	0.0
	Apr-10	34.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	967.0	0.0	0.0	0.0	1001.0	0.0	0.0	0.0
Summer 2010	May-10	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1090.0	0.0	0.0	0.0	1090.0	0.0	0.0	0.0
	Jun-10	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	715.0	0.0	0.0	0.0	715.0	0.0	0.0	0.0
	Jul-10	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	715.0	0.0	0.0	0.0	715.0	0.0	0.0	0.0
	Aug-10	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	715.0	0.0	0.0	0.0	715.0	0.0	0.0	0.0
	Sep-10	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	715.0	0.0	0.0	0.0	715.0	0.0	0.0	0.0
	Oct-10	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	715.0	0.0	0.0	0.0	715.0	0.0	0.0	0.0
Winter 2010-2011	Nov-10	437.3	0.0	0.0	76.4	128.2	0.0	0.0	0.0	490.0	0.0	0.0	0.0	1055.5	0.0	0.0	76.4
	Dec-10	158.6	0.0	0.0	0.0	128.2	0.0	0.0	0.0	40.0	0.0	0.0	0.0	326.8	0.0	0.0	0.0
Capability Period	Month	Spot Auction				Strip Auction				Monthly Auction				Total			
		HQ	IESO	NE	PJM	HQ	IESO	NE	PJM	HQ	IESO	NE	PJM	HQ	IESO	NE	PJM
Winter 2010-2011	Jan-11	0.0	0.0	0.0	0.0	128.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	128.2	0.0	0.0	0.0
	Feb-11	0.0	0.0	0.0	0.0	128.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	128.2	0.0	0.0	0.0

	Mar-11	0.0	0.0	0.0	0.0	128.2	0.0	0.0	0.0	3.7	0.0	0.0	0.0	131.9	0.0	0.0	0.0
	Apr-11	155.7	0.0	0.0	0.0	128.2	0.0	0.0	0.0	216.5	0.0	0.0	0.0	500.4	0.0	0.0	0.0
Summer 2011	May-11	138.0	0.0	0.0	0.0	235.4	0.0	0.0	0.0	190.7	0.0	0.0	0.0	564.1	0.0	0.0	0.0
	Jun-11	150.3	0.0	0.0	0.0	235.4	0.0	0.0	0.0	153.9	0.0	0.0	0.0	539.6	0.0	0.0	0.0
	Jul-11	166.4	0.0	0.0	0.0	235.4	0.0	0.0	0.0	148.7	0.0	0.0	0.0	550.5	0.0	0.0	0.0
	Aug-11	100.0	0.0	0.0	0.0	235.4	0.0	0.0	0.0	175.0	0.0	0.0	0.0	510.4	0.0	0.0	0.0
	Sep-11	120.0	0.0	0.0	0.0	235.4	0.0	0.0	0.0	150.0	0.0	0.0	0.0	505.4	0.0	0.0	0.0
	Oct-11	50.0	0.0	0.0	0.0	235.4	0.0	0.0	0.0	50.2	0.0	0.0	0.0	335.6	0.0	0.0	0.0
Winter 2011-2012	Nov-11	169.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	460.0	0.0	0.0	0.0	629.0	0.0	0.0	0.0
	Dec-11	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Jan-12	131.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	131.9	0.0	0.0	0.0
	Feb-12	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	109.8	0.0	0.0	0.0	109.8	0.0	0.0	0.0
	Mar-12	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.6	0.0	0.0	0.0	3.6	0.0	0.0	0.0
	Apr-12	254.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	102.3	0.0	0.0	0.0	356.4	0.0	0.0	0.0
Summer 2012	May-12	84.8	0.0	0.0	0.0	250.0	0.0	0.0	0.0	85.0	0.0	0.0	0.0	419.8	0.0	0.0	0.0
	Jun-12	108.8	0.0	0.0	0.0	250.0	0.0	0.0	0.0	26.0	0.0	0.0	0.0	384.8	0.0	0.0	0.0
	Jul-12	84.8	0.0	0.0	0.0	250.0	0.0	0.0	0.0	50.0	0.0	0.0	0.0	384.8	0.0	0.0	0.0
	Aug-12					250.0	0.0	0.0	0.0					250.0	0.0	0.0	0.0
	Sep-12					250.0	0.0	0.0	0.0					250.0	0.0	0.0	0.0
	Oct-12					250.0	0.0	0.0	0.0					250.0	0.0	0.0	0.0

Notes
(1) Strip auctions are conducted seasonally, so the seasonal auction results were presented for each month.

Sources
(1) All data was taken from the ICAP Data & Information section of the NYISO's web site: http://www.nyiso.com/public/markets_operations/market_data/icap/index.jsp

Table 44
1 and 4 Year Peak Load Projection Comparisons

	Summer			Winter		
	1-Year Projection	4-Year Projection	Actual Peak Load	1-Year Projection	4-Year Projection	Actual Peak Load
2000	30200	-	28138	24250	-	23764
2001	30620	-	30982	24760	-	23713
2002	30475	-	30664	24490	-	24454
2003	31430	-	30333	24090	-	25262
2004	31800	31300	28433	25620	25110	25541
2005	31960	32220	32075	25350	25560	24947
2006	33295	32460	33939	26311	25500	25057
2007	33447	33020	32169	25324	25040	25021
2008	33809	33630	32432	25293	26520	24673
2009	33452	33770	30844	24998	26550	24074
2010	33025	35042	33452	24289	27615	24652
2011	32712	35141	33865	24533	26656	23901
2012	33295	35112	-	24832	26472	-
2013	-	34080	-	-	25285	-
2014	-	33897	-	-	24896	-
2015	-	33678	-	-	24829	-
2016	-	34345	-	-	25149	-

Sources

(1) 1 and 4 year projections were taken from both Table I-1 and I-2 of the Gold Book for 2001-2003 and from only Table I-1 in all other years.
(2) Historic peak load was taken from Table I-4a of the Gold Book.

Notes

(1) 1-Year Projection is the projection for the current year, and 4-Year Projection is the projection from 4 years previous;
the 2010 line gives the projection for 2010 from the 2010 Gold Book and the 2006 Gold Book.

(2) 2000-2003 data is adjusted for DSM; 2004-2011 are before EDRP adjustments. The 2012 Gold Book doesn't indicate whether the projections given are before or after EDRP adjustments.

(3) There was a note in the 2004 GB Table I-1 saying "2004 Peak demand corresponds to 2004 ICAP results, based on normal weather, & summed over TO projections".
(4) There was a note in the 2005 GB Table I-1 saying "2005 Peak demand corresponds to 2005 ICAP results".

Appendix A

Derivation of Illustrative Reliability Based Demand Curves with Zero Crossing Points

Table A-1 derives the cost of a load shedding event using a zero crossing point for the local capacity demand curves, i.e. ignoring the fact that the local loss of load probabilities are calculated relative to the value of NYCA capacity.

Table A-1
Implied Monthly Cost of Load Shedding Event

	NYCA	Zone J	Zone K	LHV
Reference Price	$8,840	$19,190	$9,980	$8,840
100 * ΔLOLE / Δ Capacity	0.0031	0.0075	0.0113	0.0060
Implied Cost of Load Shedding	$289,352,678	$254,427,417	$88,081,548	$146,390,400

The loss of load expectations for Zone J and Zone K in Table 19 and Table 20 can then be used to derive demand curves with zero crossing points at the capacity level at which the change in loss of load expectation for incremental local capacity as shown in Table A-2.

Table A-2

Percentage of Requirement	Using No Price Floor		
	NYCA	New York City	Long Island
90%	$64,678	$87,060	$39,720
93%	$36,708	$54,644	$24,154
95%	$23,224	$42,656	$17,713
98%	$12,361	$23,990	$11,272
100%	$8,840	$19,190	$9,980
103%	$6,493	$15,991	$9,119
105%	$2,248	$9,329	$5,636
108%	$3,246	$7,998	$4,294
110%	$3,371	$2,666	$3,221
113%	$499	$888	$2,684
115%	$0	$0	$1,610
118%	$0	$0	$537