NYISO Capacity Market

Evaluation of Options

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ACRONYMS AND ABBREVIATIONS

Acronym or Abbreviation	Description
AG	Analysis Group, Inc.
CAPM	Capital Asset Pricing Model
CARIS	Congestion Assessment and Resource Integration Study
CONE	Cost of New Entry
CPV	Competitive Power Ventures
CSO	Capacity Supply Obligation
CSPP	Comprehensive System Planning Process
DSCR	Debt Service Cover Ratio
EERP	Expected Economy-wide Risk Premium
EFORd	Equivalent Forced Outage Rate – Demand
EIA	Energy Information Administration
FCM	Forward Capacity Market (ISO-NE)
FERC	Federal Energy Regulatory Commission
FM	Forward Market
G-J	G-J Locality
HQ	Hydro Quebec
ICAP	Installed Capacity
IESO	Independent Electricity System Operator (Ontario)
IRM	Installed Reserve Margin

ISO	Independent System Operator
ISO-NE	New England Independent System Operator
kW	Kilowatt
kWh	Kilowatt-hour
kW-mo	Kilowatt-month
LCR	Locational Capacity Requirement
LI	Long Island
LIPA	Long Island Power Authority
LOLE	Loss of Load Expectation
LTPP	Local Transmission Planning Process
MMU	Market Monitoring Unit (Potomac Economics)
MW	Megawatt
MWh	Megawatt-hour
NEPA	New Entry Price Adjustment
NRC	Nuclear Regulatory Commission
NYC	New York City
NYCA	New York Control Area
NYISO	New York Independent System Operator
NYPA	New York Power Authority
PILOT	Payment in Lieu of Taxes
PJM	PJM Interconnection

PPA	Power Purchase Agreement
PSC	New York Public Service Commission
REV	New York Reforming the Energy Vision proceeding
RFP	Request for Proposal
RIP	Responsible Interface Party
RMR	Reliability Must-Run
RNA	Resource Needs Assessment
ROS	Rest-of-State
RSSA	Reliability Support Services Agreement
RTO	Regional Transmission Organization
SCR (NYISO)	Special Case Resource
SCR (Technology)	Selective Catalytic Reduction
SM	Spot Market
TOTS	Transmission Owner Transmission Solution
UCAP	Unforced Capacity
UDR	Unforced Deliverability Rights
USEPA IPM	United States Environmental Protection Agency Integrated Planning Model
WACC	Weighted Average Cost of Capital

I. EXECUTIVE SUMMARY

A. Summary of Findings

In recent years, the structure of capacity markets has been the focus of intense scrutiny – and frequent change – in virtually every U.S. wholesale electricity market region. Both of New York's neighboring U.S. power regions – New England Independent System Operator (ISO-NE) and the PJM Interconnection (PJM) – have recently proposed changes in their capacity market structures to address concerns over (among other things) fuel security and resource performance. In addition, a number of stakeholders in New York have urged the New York Independent System Operator (NYISO) to consider moving away from its current monthly capacity market structure to one involving a forward capacity procurement like those in ISO-NE and PJM, in part to address concerns over reliability and incentives for new resource investment.

This Report reviews the current spot capacity market (SM) design of the NYISO and evaluates the potential benefits and drawbacks of moving to a forward capacity market (FM) design. The purpose of our review is to provide the NYISO and stakeholders with a quantitative and qualitative analysis of the two competing market structures, considering the market designs of other regions, the unique circumstances in New York, and the potential benefits, costs and impacts of changing the current structure. We model and evaluate key differences between the current spot market and a potential forward capacity market structure, including (a) market clearing outcomes and impacts, (b) reliability, (c) economic and market effects, and (d) administrative costs.

Importantly, a review of market design options before the NYISO does not start from a blank slate. There is an existing wholesale market structure that has operated (and operates) – in tandem with planning processes and operational procedures – to reliably and economically meet New York demand for decades. It is often asked, if New York's capacity market design has worked reasonably well in ensuring power system reliability and market efficiency, why "fix" it? Thus the question we review is not "which capacity market design is better?" Instead, starting with the status quo and considering all potential benefits and drawbacks, the question is "do the expected benefits of *moving to* a FM structure outweigh the potential costs and risks of changing market designs at this point?"

Overall, based on the modeling of potential market outcomes and our evaluation of many tradeoffs between market structures, we conclude that the move to a forward capacity market structure in New York is not warranted. We come to this conclusion based on several key factors:

First, the results of modeling differences between FM and SM structures on clearing prices, quantities, and costs to load/payments to suppliers do not suggest potential benefits that are sufficiently high to warrant a switch in market structure at this time. Specifically, comparing a FM structure to the NYISO's existing SM structure, we find that the move to a FM structure would change costs to load by between -$105 million to $207 million, depending on a number of assumptions related to the impact of alternative structures on the forecasting of load, cost and level of new entry, and other factors. This does not include likely incremental NYISO administrative expenses to create the FM structure of on the order of tens of millions of dollars (discussed in more detail below).

In addition to this straight-up comparison of FM and SM structures, we review the potential impact of a number of specific capacity market design features or characteristics that could be incorporated in or result from a new FM structure – namely, (a) the inclusion of an optional price lock-in for new resources in the forward capacity market structure, and (b) the requirement for more advanced notice of retirement, and (c) and whether and to what extent a forward market structure involves an over-forecasting of supply needs on a systematic basis. These key drivers of modeling results are in some senses separate from the narrower question of whether to administer a forward or spot market structure. It might be possible to obtain the potential benefits (or avoid the potential costs) of these features by including them in the current SM structure or through some other less expensive mechanisms that can be more readily implemented within the existing SM structure.

Second, a move to a forward market structure would involve significant costs and significant internal resources (potentially diverted from other projects) over several years, and in the end the forward market structure that is ultimately implemented is uncertain, as it would require comprehensive stakeholder and FERC reviews. These strike us as introducing a significant cost and a fair amount of uncertainty over the end results. Given these circumstances, the decision to move forward must be based on strong and convincing evidence of significant long-term benefits, and we are not convinced that evidence is present. Finally, there are a number of reliability-based and economic-based potential benefits and costs that while relevant, are not strong enough to overcome these general observations. Specific additional findings, discussed in more detail below, include the following:

- The existing capacity market has worked reasonably well, in part due to a well-designed and functioning energy market and the NYISO biannual Comprehensive System Planning Process, and while the move to a FM structure would be manageable with sufficient lead time, it would be costly and resource-intensive during the change process.
- Modeling results highlight variations in results by resource type, zone, and the accuracy of the FM load forecast:[1]
    - A forward market would tend to increase the total cost to load for New York consumers in the range of -$105 million to +$207 million, relative to the spot market results modeled in the same scenario. Relative to total procurement costs, these changes are relatively modest, particularly in light of the many non-quantified factors that distinguish outcomes under a forward and spot market structures. We note many, but not all, of

[1] These results reflect modeling analysis comparing a SM and FM structure, without including in the FM structure an optional new entrant lock in feature. The potential impact of a new entrant price lock in is evaluated separately, below.

these factors in this Executive Summary.

  - With a forward market, prices are higher (or unchanged) and the quantity of resources procured is lower (or unchanged). These impacts are due to higher offers from existing capacity due to factors such as the opportunity cost of committing a resource three years in advance (due to loss of flexibility to retire, mothball, or supply into other markets) and the greater risk of resource deficiency payments.
  - Model results can differ substantially by region, depending on the shape of the supply curve and the presence of market mitigation. The largest impacts from transitioning to a forward market occur in Long Island and Western New York (zones A-F).
  - Model results are most sensitive to assumptions about load forecasts. This has several important implications. When procurement reflects an "accurate" (unbiased) forecast of needed resources in the delivery year, a forward market can reduce the variability of costs to load compared to a spot market (even if the expected cost to load is somewhat higher). However, any tendency to over- or under-procure resources in the forward auction would create an asymmetric risk, particularly for over procurement, which would lead to higher costs to load due to the elevated prices in the initial forward auction.

- Under a forward market, the timing of information about changes in resource availability provides greater opportunity for orderly development of solutions to fill resource gaps or address reliability concerns. This earlier information comes at an economic cost, as the three-year-ahead commitment from resources may limit optionality and create delivery risks for suppliers. Alternative regulatory changes, such as longer required retirement notification, may also achieve the benefits of more timely information about resource retirements.

- Under a forward market, there is a three-year lag between the initial procurement and the delivery year, meaning there is a significant lag between any rule changes designed to affect reliability/market efficiencies and the initial period when those rules go into effect. This inefficiency would be expected to increase costs in nearly all circumstances.

- To the extent that state- or utility-supported reliability solutions (e.g. Reliability Support Services Agreements (RSSA)) might be required, a forward market provides greater opportunity to develop alternative solutions and negotiate such agreements under less time pressure than that caused by 180 day mandated retirement notice period in the NYISO's current market design. The longer lead-time before resources solutions are needed with a forward market may also reduce the length of RSSAs, which can limit any distortions in capacity market prices such agreements may create.

- A forward market may create support for the entry of new resources by "coordinating" competition among new entrants (to avoid excess entry), and allowing resources to offer at their cost of new entry (albeit for only one year). However, there are tradeoffs, including deficiency risk if the resource is not in-service within three years.

- The current ICAP market structure has operated with relatively few changes since 2003. The relative certainty created by this market stability is important to ensuring the investor confidence in NYISO markets needed to secure investment in new and existing resources. The process of shifting to a forward market structure could create a period of uncertainty in NYISO capacity markets.

- While it exists in the ISO-NE and PJM capacity markets, the inclusion of a price lock-in for new resources is not a necessary feature of moving to a FM structure. However, in moving to a FM structure, NYISO would have the *option* of including a new entrant price lock-in. In addition to the results above, we come to the following conclusions with respect to the potential impact of including a price lock-in in the FM structure:

    - A price lock-in would improve the incentives for new entry, thus increasing the likelihood that market-based generation enters to address resource adequacy needs. However, a price lock-in option entails costs that are difficult to observe, including the risk that a multi-year price lock in may increase the incentive for new entrants to submit offers above their true costs. Further, establishing a lock-in *only* for new resources may lead to a less efficient use of capital, resulting in premature retirements of existing plants. Both factors would transfer risk (and associated costs) from developers of new facilities to loads and, ultimately, consumers. We do not attempt to model such strategic actions by bidders in our current model.

    - A forward market with a new entry lock-in would be expected to lower the total cost to load for New York consumers across a range of scenarios (relative to a SM without a lock-in), since it lowers the net cone and can lower costs of finance for new resources by lowering the financial risk. Specifically, we find that across all scenarios, with the inclusion of a lock-in within a FM structure, the total cost to load for New York consumers would vary relative to the spot market by -22% to 35%. At historical ratios, the total impact to *all-in prices* would be between -3.3% and 5.3%. However, to the extent that a price lock-in lowers procurement costs, this benefit comes at the expense of existing resources that earn lower capacity market revenues and not through any improvement in economic efficiency.

B. Background

The New York Independent System Operator is responsible for reliable operation of New York's bulk power system, administration of efficient and competitive wholesale power markets for New York State, and ongoing planning activities to identify future system needs. Specifically, NYISO provides benefits to consumers by (1) maintaining and enhancing regional reliability, (2) administering open, fair, and competitive wholesale markets, (3) helping plan the power system for the future, and (4) providing factual information to policy makers, stakeholders, and investors in the power system. In meeting these obligations, NYISO continuously evaluates the wholesale markets it administers in order to assess the efficiency of New York's electricity markets, and to identify changes to market structures if and when such changes can improve reliability and/or economic outcomes. This Report is designed to inform this ongoing assessment with respect to the design and operation of New York's capacity market.

In recent years, the structure of capacity markets has been the focus of intense scrutiny – and frequent change – in virtually every U.S. wholesale electricity market region. Both of New York's neighboring U.S. power regions – New England Independent System Operator and the PJM Interconnection – have recently proposed changes in their capacity market structures to address concerns over (among other things) fuel security and resource performance. In addition, a number of stakeholders in New York have urged NYISO to consider moving away from its current monthly capacity market structure to one involving forward capacity procurement like those in ISO-NE and PJM, in part to address concerns over reliability and incentives for new resource investment.

Past studies commissioned by NYISO to review its capacity market have suggested that a forward market structure could in theory provide benefits (relative to its spot market structure) but, overall, the move to a FM structure was neither necessary nor warranted in consideration of then-current market and system conditions, and the relatively successful experience with the existing SM structure. But the state of New York has recently faced, and continues to face, potentially significant changes to existing electricity resources, expected conditions of supply and demand, and the structure of power supply and demand at the distribution level.

Changes that could stress the reliability and efficiency of New York's wholesale markets include an accelerated attrition of regional infrastructure due to economic and environmental pressures; new challenges related to unit fuel security and performance; potential changes in the structure of the industry in the state and growth in distributed supply and demand technologies; and other developments that could significantly change the landscape of electricity supply and transmission across New York. Considering the changing landscape and the evolution of forward market structures in neighboring regions, NYISO retained Analysis Group (AG) to evaluate the benefits, drawbacks, and potential impacts of moving to a FM structure in the New York.

This Report reviews the current spot capacity market design of the NYISO and evaluates the potential benefits and drawbacks of moving to a forward capacity market design. The purpose of our review is to provide the NYISO and stakeholders with a quantitative and qualitative analysis of the two competing market structures, considering the market designs of other regions, the unique circumstances in New York, and the potential benefits, costs and impacts of changing the current structure. We evaluate how resource adequacy is currently maintained in the New York bulk power system (and the role that the current capacity market structure plays in that), and how New York's capacity market design compares with capacity markets in neighboring regions. We evaluate qualitatively the various arguments for, and against, moving towards a forward market structure. And we model the potential impact of a FM structure – relative to the current SM structure – from the standpoints of clearing prices and quantities, resource outcomes, revenues to generators, and costs to load.

Our analysis specifically models the impact of including a mandatory auction three years prior to the year of need. This FM structure is similar to the capacity markets administered by neighboring control regions (ISO-NE and PJM), and has been considered previously in New York as an alternative to the current SM structure. The design features we assume for the FM structure are consistent with those developed previously by NYISO in consultation with stakeholders in the Installed Capacity Market (ICAP) Working Group.

A price "lock-in" for new resources that clear the market is not a necessary feature of the move to a FM structure; thus, we first report results assuming no price lock-in. However, ISONE recently established a seven year lock-in for new resources, and PJM also has a price lock-in feature in its market structure. In the move to a FM structure NYISO would have the option to also include a new resource price lock-in. Thus, in order to *separate and highlight* the impact of including a price lock-in option in the move to a FM structure (compared to a SM structure), we also analyze in quantitative modeling scenarios the results assuming a 7-year lock-in for new capacity resources.

C. Approach

Our review of moving to a forward capacity market structure for the NYISO focuses on identifying and evaluating key differences between the current SM structure and a potential FM structure. Specifically, we consider potential differences from the perspectives of (a) market clearing outcomes and impacts, (b) reliability, (c) economic and market effects, and (d) administrative costs. We use Analysis Group's capacity market model to estimate differences between spot and forward market structures, and we evaluate additional key features through quantitative assessment of market circumstances and past wholesale market results; estimation of the administrative costs to implement a new capacity market structure; and qualitative evaluation of key reliability and market efficiency metrics drawn from a review of relevant analyses and reports.

Importantly, a review of market design options before the NYISO does not start from a blank slate. There is an existing wholesale market structure that has operated (and operates) – in tandem with planning processes and operational procedures – to reliably and economically meet New York demand for decades. Thus it is often asked, if to-date New York's capacity market design has worked reasonably well in ensuring power system reliability and market efficiency, why "fix" it? The question then is not "which capacity market design is better?" Instead, starting with the status quo and considering all potential benefits and drawbacks, the question is "do the expected benefits of *moving* to a FM structure outweigh the potential costs and risks of changing market designs at this point?"

This is the framework within which we review a potential forward market structure in New York – we consider theoretical and quantitative evidence, as well as political and practical realities. We not only evaluate the many arguments for and against change, we specifically quantify the potential impacts of a forward market (relative to the spot market) from the perspectives of clearing prices, resource quantities, costs to load, and the administrative impacts and costs to NYISO to process and implement the move to a FM structure. Specifically, our analysis contains the following:

- A capacity market model structured to compare market outcomes in a future year (2020) under (a) the current SM structure, and (b) a FM structure, using inputs and assumptions consistent with current NYISO planning assumptions. Model results are tabulated as differences in clearing price and clearing quantity, revenues to generators, and costs to load. Results are modeled for a number of different scenarios and sensitivities to assess impacts under different market circumstances and the sensitivity of model results to different demand, supply, and other assumptions/inputs. In addition, scenarios are modeled with and without a seven-year lock-in for new resources to separately quantify the impact of this specific market design option.
- A review of the potential impact on new entry costs (and by extension the impact of moving to a FM construct) of a price lock-in for new resources clearing the market, based on available data on the cost of debt and equity for recent new power plant investment across a variety of market constructs.
- A comparative and qualitative evaluation of the potential benefits and drawbacks of moving to a FM structure based on analysis of market outcomes in different regions and a literature review of reports evaluating capacity market designs.
- An assessment of the administrative costs and implications for NYISO as an organization in moving to a FM structure, based on research into the cost to administer NYISO's current capacity market structure versus resources required to implement forward market structures in neighboring regions (ISO-NE and PJM).

This Report presents the results of our analysis and research. We consulted throughout the project with NYISO staff and the NYISO MMU – Potomac Economics – on modeling inputs and assumptions; details on NYISO's wholesale markets, market clearing structures, market monitoring, and planning procedures; relevant questions of jurisdictional and regulatory context and shared governance; and administrative features of designing and administering current market structures and proposed market rule changes. However, the findings and recommendations in this Report are our own, and do not necessarily reflect the judgments or conclusions of the NYISO or the MMU.

D. Results and Observations

The design and administration of capacity markets at U.S. ISO/RTOs over the past decade have been neither easy in principle, nor particularly smooth in practice. In every electricity market region, design outcomes result not only from sound economic principles but also from negotiations among disparate, competing interests. Design and administration of capacity markets is also challenged by the lumpiness of major investment (and retirement) cycles, the inability to store product, and an array of challenging and jurisdictional and regulatory constraints. Not surprisingly, in many regions the evolution of capacity market design has resulted from a continuous series of negotiations/litigations, rather than from a single, principled design event.

This also complicates NYISO's consideration of moving to a new capacity market structure. Deciding whether to change from one capacity market structure to another depends strongly on the purpose for the change, and on expectations around whether the market rule that is likely to emerge from stakeholder and regulatory processes will accomplish the desired objectives. Is the specific goal to minimize customer costs, or minimize customer risks? Maximize power system reliability? Minimize administrative burdens? Alter demand, change the resource mix, or otherwise achieve specific energy or environmental policy goals? Meet state and local economic development interests? Manage specific operational challenges? Or some combination of the above?

The answer NYISO may give – based on their reliability mandate and market efficiency and competitiveness objectives – may differ from that of New York state, consumer and other load interests, generating asset owners, transmission and distribution utilities, new project developers, and energy/environmental policy interests. We recognize that practitioners, market participants, and other stakeholders will find many different ways to interpret data and research on the proper form and administration of capacity markets, and different perspectives on the importance of individual pieces of the puzzle – including economics, reliability, cost, and policy goals. Based on our research and analysis, we come to a number of core observations and conclusions, summarized here and supported in detail throughout the Report.

E. Context, Practical Considerations, and Conclusions

- ***The Existing Capacity Market Has Worked Reasonably Well, in Part Due to a well-designed and functioning energy market and the NYISO' biannual Comprehensive System Planning Process*** – NYISO's spot capacity market has worked well from a number of perspectives – it is a functioning, fluid and competitive market; it has not changed significantly over many years, and experience with capacity markets in other regions indicates that regulatory stability is an important factor influencing investor confidence and willingness to develop resources on a merchant basis; resource adequacy and system security have been maintained throughout time; and resource changes have been managed without any interruption in service or reliability failures. However, from a reliability perspective the success of NYISO's capacity market is supported through a comprehensive planning process not found in other regions with a FM structure. In particular, the NYISO planning process identifies reliability problems well in advance, and ensures that resources are developed in a timely manner to address them; to the extent market-based supply or demand resources do not materialize as a result of the planning process, transmission owners implement backstop supply and/or transmission solutions.

- ***Careful Consideration of Capacity (and Other) Market Structures is Warranted Given the Pace***

and Magnitude of Potential Changes to the State's Infrastructure and Industry Structure Over the Planning Horizon – NYISO estimates that up to 33,200 MW of summer capacity could be affected to some extent by recent safety and environmental regulations affecting power plants, with 13,650 MW potentially facing significant operational impacts.[2] These units include all coal units, the Indian Point nuclear station, and several large oil and gas steam turbines, and decisions on whether to move forward with retrofit investments or retire will be needed over the next few to several years. Major repowering, contracting and transmission investments are all in play to address known reliability needs. And New York State has embarked on the Reforming the Energy Vision (REV) proceeding which could significantly change the structure and operations of the industry at the distribution level, and through behind-the-meter installations, change the variability of power supply and demand in fundamental ways. All of the above suggest that a potentially fundamental shift in power supply infrastructure in New York over the next ten years is looming, one that requires diligence from both planning and market perspectives.

- ***The Move to a Forward Market Structure in New York Would be Somewhat Costly and Resource Intensive, but Manageable with Sufficient Lead-Time*** – Based on a review of the major software changes and design, stakeholder and regulatory experiences in moving to FM structures in ISO-NE and PJM, it is reasonable to expect that moving to a FM structure in New York would (a) require a full reworking of market software, (b) involve an up-front expense of on the order of a couple to a few tens of millions of dollars, and (c) require substantial commitment of existing staff time for market design, administration through the shared governance process, regulatory approvals, and initial implementation. On the other hand, the annual administration of a FM structure would likely not require a major change in resource requirements relative to administration of the current SM structure, but would likely require the re-purposing of existing staff to different areas. Finally, the experience in other regions suggests moving software design in-house, and a minimum of three years for proper processing and implementation of a new FM structure.

- ***Overall, Based on the Modeling of Potential Outcomes and Our Evaluation of Many Tradeoffs Between Market Structures, We Conclude that the Move to a Forward Market Structure in New York is Not Warranted*** – We come to this conclusion based on several key factors. First, the potential impacts on clearing prices, quantities, and costs to load/payments to suppliers do not suggest potential benefits in switching market structures at this time. To the extent that impacts are meaningful, they are a function of features of market design that are optional, and whether and to what extent a forward market structure leads to an over-forecasting of supply needs on a systematic basis. Second, a move to a forward market structure would involve significant costs and significant internal resources over several years, and in the end the forward market structure that is ultimately implemented is uncertain, as it would require comprehensive stakeholder and

[2] NYISO, "2014 Reliability Needs Assessment," Table 5-5 and 5-6.

FERC reviews. Moreover, these types of market changes would interrupt the current market stability, which itself is an important ingredient to supporting investor confidence. These strike us as introducing a significant cost and a fair amount of uncertainty over the end results. Given these circumstances, the decision to move forward must be based on strong and convincing evidence of long-term benefits, and we are not convinced that evidence is present. We also review a number of reliability-based and economic-based potential benefits and costs that while relevant, are not strong enough to overcome these general observations.

Finally, certain optional design choices can affect the comparison of the FM structure to the current SM structure, such as (a) whether or not an optional price lock-in for new resources is allowed in the forward capacity market structure, and for how long (although impacts do necessarily reflect efficiency improvements, but rather, transfers of funds and risk from supply to load); and (b) whether advanced notice of retirement is a feature of the forward market structure *but not the spot market structure to which it is compared*, and (c) and whether and to what extent a forward market structure involves an over-forecasting of supply needs on a systematic basis. These can change modeling results and in fact improve results compared to a SM structure, but since they are optional market design features they are separate from the narrower question of whether to administer a forward or spot market structure. It might it be possible to obtain the potential benefits (or avoid the potential costs) of these feature through some other less expensive mechanisms that can be more readily implemented.

1. Modeling Approach and Outcomes

- ***Modeling Results Highlight the Importance of the Accuracy of the Forward Market Load Forecast, and Regional Differences*** – We modeled the expected differences between a forward and spot market under six scenarios designed to account for instances of new entry, generator retirements, and changes in load expectations. We find:[3]

    a. A forward market would be expected to <u>affect both the supply and demand curves</u>, compared to a spot market. Shifts in the supply curve are reasonably certain, and would be expected in all regions for existing generation. In contrast, any shift in the demand curve (relative to a SM design) depends heavily on the optional decision to offer a price lock-in for new resources, and on the impact of less-precise load forecasting (three years out in a FM structure).

    b. With respect to the <u>supply curve</u>, a forward market would create additional uncertainty for existing resources. Resources would increase their capacity price bids to account for this risk. On net, an increase in costs for existing resources will both increase

[3] These results reflect modeling analysis comparing a SM and FM structure, without including in the FM structure an optional new entrant price lock-in feature. The potential impact of a new entrant price lock in is evaluated separately below.

clearing prices and reduce the total quantity of resources procured.

c. With respect to the demand curve, one way to affect it is to alter the degree of revenue certainty by including a price lock-in for new resources; we review these results separately, below. A forward market without a lock-in would increase the total cost to load for New York consumers in years without new entry, due in part to an increase in costs for existing units that account the opportunity cost of committing a resource three years in advance (due to loss of flexibility to retire, mothball, or supply into other markets) and the greater risk of resource deficiency payments. Across a number of scenarios, the range of total cost to load impacts is -$105 million to +$207 million.[4] These costs could be higher or lower, depending on a number of assumptions related to the impact of alternative structures on the forecasting of load, cost and level of new entry, and other factors. Clearing prices tend to be higher in scenarios without new entry than in the same spot market scenario, particularly in non- mitigated zones. This is due to the increase in estimated offers of existing resources in a forward market.

d. Model results can differ substantially by region, depending on the shape of the supply curve and the presence of market mitigation. The largest impacts to a forward market occur in Long Island and in Western New York (zones A-F). In these regions, the supply curve is relatively steep relative to the demand curve. Decisions that impact the marginal unit in these zones have a greater impact on offer prices, clearing prices, and the total cost to load.

e. Modeling results are most sensitive to assumptions about load forecasts. This has several important implications. When procurement reflects an "accurate" (unbiased) forecast of needed resources in the delivery year, a forward market can reduce the variability of costs to load compared to a spot market (even if the expected cost to load is somewhat higher). However, any tendency to over- or under-procure resources in the forward auction would create an asymmetric risk, particularly for over procurement, which would lead to higher costs to load due to the elevated prices in the initial forward auction. This difference can be significant, and the total change in cost to load accounting for load uncertainty could in a given year be greater than nearly any other parameter, including a lock-in. We also find evidence that in recent years, operating forward markets have tended to clear excess supplies due to an over-forecast of load, effectively shifting demand curves further to the right. Therefore, load forecasts may present an asymmetric risk, in which over-forecasting, and over-procurement (relative to the capacity needed to meet reliability targets) result in higher costs to load.

[4] These results represent short-term impacts in the year 2020 and do not explicitly consider long-run changes to the generator fleet. These results also assume no error in load forecasts.

f. Across all scenarios, including estimates of over- and under- load forecasts, we find that the change in total cost to load for New York consumers could vary between -17% and +46% relative to the spot market modeled for each scenario. At historical ratios, the total impact to *all-in prices* would be between -2.5% and 6.9%. (Historically, capacity prices have represented approximately 15% of total consumer costs; therefore, an increase in the total cost to load, relative to the spot market, of 10% would tend to increase the total cost all in cost to consumers by 1.5%.)

- ***Including an optional lock-in in the FM structure (but not the SM structure to which it is compared) significantly affects results.*** A forward market with a lock-in would be expected to lower the total cost to load for New York consumers across a range of scenarios. However, the cost of load reductions with a price lock-in only for new resources reflect, in part, transfers of risks and costs from suppliers to load, rather than reductions in underlying risk and costs. These risk transfers may lead to a less efficient use of capital, resulting in premature retirements of existing plants. As discussed below, the long-run transfer of risk is not captured in the current modeling results.

a. A forward market with a lock-in for new entry would provide additional revenue certainty for generators. We expect this would lower financing costs and net CONE (our base case estimate is by 125 basis points for debt and 139 basis points for equity). Based on this impact on the demand curve only, a forward market with a lock-in tends to reduce clearing prices in all zones across a number of scenarios. However, a lower demand curve also procures a lower quantity of total capacity. Thus, a forward market with a lock-in tends to both reduce the clearing price and reduce the total clearing quantity of capacity.

b. A forward market with a lock-in could increase the total quantity of *new* entry. This impact is based on the estimates for net CONE that account for the price certainty of a new resource lock-in. The lower cost of new entry will translate to lower offers from new resources, likely resulting in a higher quantity of new capacity clearing the market. This result is particularly true in both Long Island and in Western New York, because estimates for net CONE are below existing marginal units. It is also true in scenarios with resource retirements. Our modeling analysis does not consider the possibility that merchant entry would not occur absent a 7-year lock-in (at any price).

c. A forward market with a lock-in tends to lower the net CONE on the demand curve, shifting it down and to the left. This could potentially cause existing capacity offers to be above the demand curve, reducing the total quantity of procured capacity. The lower demand may nevertheless decrease clearing prices, and lower the total cost to load.

d. Across all scenarios, including estimates of over- and under- load forecasts, we find that the change in total cost to load for New York consumers could vary between -22%

and +35% relative to the spot market modeled for each scenario. At historical ratios, the total impact to *all-in prices* would be between -3.3% and +5.3%.

2. Additional Observations

a. Under a forward market, the timing of information about changes in resource availability provides greater opportunity for orderly development of solutions to fill resource gaps or address reliability concerns. This earlier information comes at an economic cost, as the three-year-ahead commitment from resources may limit optionality and create delivery risks for suppliers. Potential advanced solutions can include new development, which can directly compete in a forward market, or lead to more responsive demand response or imports. Within the context of NYISO's resource adequacy construct and comprehensive reliability planning process – which provides greater advanced opportunity for market-, state- or utility-supported solutions – such timing is of less value than it is in other regions that rely more heavily on an organized capacity market to achieve resource adequacy. Alternative regulatory changes, such as longer required retirement notification, may also achieve the benefits of more timely information about resource retirements.

b. A forward market's reliability benefits derive from the procurement of physical, not financial commitments. As a result, provisions may be required in a forward market to avoid financial speculation, particularly if there are perceived forecasting biases.

c. Under a forward market, there is a three-year lag between the initial procurement and the delivery year, meaning there is a significant lag between any rule changes designed to affect reliability and the initial period when those rules go into effect. Consequently, a forward market may have greater need for interim reliability (gap) solutions that would need to be in place in advance of the required in-service date for the market design solution.

d. Some of the benefits of a forward market come at an economic cost. Given a forward market structure, resource bids will tend to be higher to reflect factors such as the opportunity cost of committing a resource three years in advance (due to loss of flexibility to retire, mothball, or supply into other markets) and the greater risk of resource deficiency payments.

e. To the extent that state- or utility-supported reliability solutions (e.g. RSSAs) are required, a forward market provides greater opportunity to develop alternative solutions and negotiate such agreements under less time pressure than that caused by 180 day mandated retirement notice period in the NYISO's current market design. The longer lead-time before resources solutions are needed with a forward market may also reduce the length of RSSAs, which can limit any distortions in capacity market prices such agreements may create.

f. A forward market may create support for the entry of new resources by "coordinating" competition among new entrants (to avoid excess entry), and allowing resources to offer at their cost of new entry (albeit for only one year). However, there are tradeoffs, including deficiency risk if the resource is not in-service within three years.

g. The current ICAP market structure has operated with relatively few changes since 2003. The relative certainty created by this market stability is important to ensuring the investor confidence in NYISO markets needed to secure investment in new and existing resources. The process of shifting to a forward market structure could create a period of uncertainty in NYISO capacity markets.

h. A price lock-in can lower costs of finance for new resources by lowering the financial risk, and thereby may lead to increased market-based entry of new resources. However, the price lock-in option entails costs that are more difficult to observe, including the risk that a multi-year price lock in may increase the incentive for new entrants to submit offers above their true costs. This tends to bias the risk of higher locked-in capacity prices that are borne by ratepayers. Further, establishing a lock-in *only* for new resources may lead to a less efficient use of capital, resulting in premature retirements of existing plants, and transferring risk (and associated costs) from developers of new facilities to loads and, ultimately, consumers. Importantly, our modeling analysis does not attempt to predict or model strategic behavior by bidders.

i.A forward market transfers certain risks to suppliers, which are then (appropriately) reflected in their offers, resulting in higher going forward costs. This transfer of risk seems appropriate, since suppliers are in a better position than load to control factors that would lead to resource unavailability. A forward market can also mitigate financial risks by reducing variability in price and cost to load. Such risk hedging is also available under a spot market, through bi-lateral contracts, that can be selected by load and supply based on the desire degree of hedging.

II. PURPOSE, CONTEXT, AND APPROACH

A. Purpose of the Analysis Group Study

The New York Independent System Operator (NYISO) is responsible for reliable operation of New York's bulk power system, administration of efficient and competitive wholesale power markets for New York State, and ongoing planning activities to identify future system needs. Meeting system reliability requirements requires, in part, sufficient regional power supply and delivery infrastructure to meet growing needs. Retaining existing infrastructure and attracting new power supply investment in turn depends on NYISO's planning procedures and the financial incentives that flow from New York's wholesale energy, ancillary services and capacity markets.

Throughout the country regional transmission operators (RTO) and independent system operators (ISO) must continuously review the performance of the wholesale markets they administer with respect to efficiency, competitiveness, and ability to meet reliability needs. Under current wholesale market designs, most regions administer some form of capacity market or capacity assurance mechanism in order to attract and retain needed power supply infrastructure. Such constructs are needed where energy and ancillary service market revenues earned by generating capacity owners do not provide sufficient revenues to recover capital expenditures and/or fixed costs for investment in new capacity or continued operation of existing resources.

Continuous evaluation of current and potential alternative market structures is an ongoing obligation for NYISO in the interest of improving the effectiveness of New York's markets. In addition, a number of stakeholders have recently suggested that NYISO may want to specifically consider the tradeoffs in moving away from its current monthly capacity market structure to one involving a forward capacity procurement, including a mandatory auction three years prior to the year of need, and an optional multiple-year price lock-in for new resources that clear the market. This forward market (FM) structure is similar to the capacity markets administered by neighboring control regions (New England Independent System Operator's (ISO-NE) Forward Capacity Market (FCM) and the PJM Interconnection's (PJM) Reliability Pricing Model (RPM)), and has been considered previously in New York as an alternative to the current spot market (SM) structure.

The potential benefits and drawbacks of modifying the structure of the capacity market in New York will change over time, as the regulatory and market landscape changes and system infrastructure conditions that underlie market and reliability performance evolve. Past studies commissioned by NYISO to review its capacity market concluded that while a FM structure might provide benefits from the perspectives of reliability and new resource development incentives, the move to a FM structure was neither necessary nor warranted in consideration of then-current market and system conditions, and the relatively successful experience with the existing SM structure[5]. But

[5] Brattle Group, "Cost-Benefit Analysis of Replacing the NYISO's Existing ICAP Market with a Forward Capacity Market" Prepared for the New York Independent System Operator, June 15, 2009.

much has changed in New York over the past several years, and additional changes are likely to occur in the coming years. Potential changes could arise due to economic and environmental pressures, new challenges related to unit fuel security and performance, the influence of changing industry structure and incentives for distributed resources affecting demand and infrastructure outcomes, and recently-proposed or implemented changes to the capacity markets in other regions.

In this Report we review the existing NYISO capacity market design and evaluate the potential benefits and drawbacks of moving towards an alternative, forward capacity market design. Our evaluation considered two potential policy decisions: (1) the decision to adopt a forward market structure (*without* a price lock-in for new resources), and (2) the decision to adopt a price lock-in for new resources (*given* a forward market structure). We do not evaluate a policy in which a price lock-in is adopted within the current spot market structure.[6]

The purpose of our review is to provide the NYISO and stakeholders with an evaluation of competing market structures, considering the market designs of other regions, the unique circumstances in New York, and the potential benefits, costs and impacts of changing the current structure. We evaluate how resource adequacy is maintained in the New York bulk power system (and the role that the current capacity market structure plays in that), and how New York's capacity market design compares with capacity markets in neighboring regions. We evaluate qualitatively the various arguments for and against moving towards a forward market structure. And we quantitatively model the potential impact of a FM structure – relative to the current SM structure – to provide estimates of clearing prices and quantities, and costs to load.

In this section we set the stage for our evaluation by providing an overview of how resource adequacy is evaluated and approached in New York, how New York's approach differs from that in neighboring regions, and how resources have evolved over time in the context of the state's current planning and market constructs. We then provide an overview of how we perform our evaluation of the capacity market question, with results presented in subsequent sections.

FTI Consulting, "Evaluation of the New York Capacity Market", Prepared for the New York Independent System Operator, March 5, 2013.

[6] In principle, a price lock-in could be adopted within the current spot market structure. However, the incentives for new resource development created by a price lock-in under a spot market would differ from those under a forward market. Under a forward market, a price lock-in reduces revenue stream uncertainty when such uncertainty creates financial risk to the developer (that is potentially mitigated by opting for the lock-in). Under a spot market, the decision to exercise the lock-in would not affect the decision to invest in new resources. Instead, the lock-in decision would be made well after the resource has been developed and would depend on whether it was profitable to exercise the lock-in option at the time the facility is able to deliver supply. Thus, in effect, the lock-in becomes purely a financial option. While giving developers this financial option would provide an additional inducement to develop resources, it would not offset the risk of revenue uncertainty, which was the original intention of the lock-in option.

B. Resource Adequacy in NYISO

System operators establish resource adequacy targets to ensure that there are sufficient resources available to meet established reliability criteria. Within NYISO, resource adequacy criteria reflect the common standard of a "1 in 10" loss of load expectation (LOLE). Because revenues from energy and ancillary services markets are generally not sufficient to ensure that the market will fully support the development and maintenance of enough resources to ensure that this reliability standard is met. As a result, the regulatory structure in New York State, reflecting the NYISO market rules, New York Public Service Commission (NY PSC) regulations and other state rules, includes a number of approaches beyond the energy and ancillary services market to ensure that resource adequacy standards are met. The result is a mix of reliability planning processes and capacity market activities unique to the New York bulk power system.

1. Current Resource Adequacy Construct within the NYISO

The NYISO relies on its Comprehensive System Planning Process (CSPP) to maintain reliability, given the long lead time to developing generation and transmission infrastructure and the need for other processes to ensure that reliability objectives are met.[7] The CSPP includes a Reliability Needs Assessment, which includes a 10-year forward-looking planning evaluation reflecting future loads, known generation and transmission resources, and system topology. The RNA identifies any unmet reliability needs over the 10-year horizon, solutions to the identified needs are solicited and evaluated by the NYISO, and the plans and schedules to be implemented to meet the defined reliability needs are established in the Comprehensive Reliability Plan (CRP). As part of this process, market participants are given the opportunity to identify market-based solutions, and Transmission Owners identify potential regulated backstop solutions to be implemented if market-based solutions do not emerge. Potential backstop solutions include new transmission investment, repowering of existing generation resources or other supply- or demand-side resource solutions.[8] As part of this process, the NYISO monitors the development progress of the market-based solution to ensure that the reliability need will be met, and in the event that a market based solution fails to meet interim development

[7] The CSPP includes a local transmission planning process (LTPP), the reliability planning process, and an economic planning process, known as the Congestion Assessment and Resource Integration Study (CARIS). During the CARIS studies, the NYISO evaluates the benefits and costs of alternative projects and evaluates specific transmission projects for regulated cost recovery. Here, we focus primarily on the role of the reliability planning process in ensuring resource adequacy. The reliability planning process includes both the Resource Needs Assessment (RNA) and the Comprehensive Reliability Plan (CRP). Historically, the CSPP has followed an approximately two year planning cycle. See both the NYISO 2014 "Reliability Needs Assessment" and the OATT Section 31, Attachment Y.

[8] The NYISO OATT specifies that regulated backstop solutions may include generation, transmission, or demand side resources (Section 31.2.4.21, Attachment Y). Governor Cuomo's New York Energy Highway Blueprint (2012) requires utilities to evaluate repowering plants as a potential solution when plants needed for reliability are scheduled for retirement.

targets, the NYISO may trigger the regulated backstop solution.[9]

The NYISO Installed Capacity (ICAP) market is a key element of this reliability construct as it provides additional revenues – the "missing money" – for resources that are needed to maintain resource adequacy but do not fully recover their costs through the NYISO energy and ancillary services markets.[10] Without the capacity market, new resources could find it uneconomic to enter the market, existing resources could retire, and the overall supply of resources could ultimately be insufficient to meet resource adequacy requirements. The NYISO ICAP market with demand curves has been in operation since 2003 and with the exception of the addition of both supply and buyer side mitigation measures and deliverability rules, there has been relatively little change to market mechanics over this period. This represents greater degree of stability in market design than has been experienced in other organized capacity markets. Such stability promotes the investor confidence required to support development of new merchant resources.

The NYISO CSPP/resource adequacy construct differs from the planning processes in ISO-NE and PJM in many respects, and needs to be viewed as an integrated approach, when considering the potential benefits of moving to a different capacity market structure. In particular, ISO-NE and PJM place greater reliance on the capacity market for maintaining resource adequacy, in comparison to NYISO. While both regions include planning processes to identify reliability needs (similar to NYISO), non-market reliability solutions are limited to backstop transmission solutions from the planning perspective.[11] This has meaningful implications for the role that the capacity market has in maintaining resource adequacy in each of these RTOs. While ISO-NE and PJM are both heavily dependent on the capacity market to maintain resource adequacy, NYISO can rely on other approaches if market-based solutions do not emerge, including solutions supported by the transmission operators such as the repowering of existing assets. This is particularly important in the context of how each of these systems responds to the retirement of existing resources. In addition, market history varies in these regions. In PJM, the RPM has been in operation since 2007.[12] Although the market continues to undergo changes in market design,[13] in recent years, meaningful quantities of new resources have

[9] See, for example, NYISO "2014 Reliability Needs Assessment", Appendix B. See also, NYISO Open Access Transmission Tariff Section 31, Attachment Y.

[10] "Missing money" is the term often used to describe the revenue needed above and beyond energy and ancillary services market revenues to attract new – or retain existing – economic resources sufficient to meet resource adequacy targets. See, e.g., Cramton, Peter and Steven Stoft, "The Convergence of Market Designs for Adequate Generating Capacity with Special Attention to the CAISO's Resource Adequacy Problem," MIT Center for Energy and Environmental Policy Research, 07-007, April 2006.

[11] While reliability solutions generally involve either market-driven resource investment or backstop transmission solutions in ISO-NE and PJM, short-notice reliability concerns have also been temporarily addressed as needed through reliability must-run (RMR) contracts and "gap" RFPs.

[12] From 1999 until the implementation of the RPM, PJM operated a capacity credit market with capacity prices at or near zero over much of this period. Bowring, Joseph, 2013, "Capacity Markets in PJM," *Economics of Energy & Environmental Policy* 2(2).

[13] For example, PJM is now proposing a new Capacity Performance Product designed to address concerns about the level of resource performance under the current market rules. PJM, "PJM Capacity Performance Updated

entered the market, indicating some level of market confidence in the market's ability to sustain prices. In ISONE, capacity markets have also undergone many changes but, until the most recent auction, prices in ISO-NE's Forward Capacity Market have been at or near the administratively-determined price floors since the market's inception for the 2010-2011 capacity year.

In this Report, we evaluate qualitatively and quantitatively the differences between NYISO's current SM capacity structure and the potential move towards a FM structure that is similar to markets currently in place in ISO-NE and PJM. [14] Consequently, when considering potential reliability implications, it is important to keep in mind the fundamentally different planning-market construct in New York, compared to that in ISO-NE and PJM. The key differences in these resource adequacy frameworks are summarized in Table 1.

Table 1: Approaches to Resource Adequacy Across RTOs

Element	NYISO	ISO-NE / PJM
Scope of Planning Process	• CSPP- Resource adequacy and reliability (security, voltage support, stability, etc.) • IRM / LCR Setting Processes establish locational resource requirements	• Resource adequacy and reliability (security, voltage support, stability, etc.). Resource Adequacy findings translate into capacity market quantity objectives
Potential Solutions Considered	• Generation, Transmission, Other Market- based Solutions (MBS)	• Transmission
Process of Identifying Solutions	• MBS can come forward in effort to avoid transmission investment • Least-cost solutions to ensuring resource adequacy and reliability identified • Regulated Solution triggered if MBS fails to materialize on time	• Transmission solutions (and potential non- transmission alternatives) to ensuring reliability • Action take several years prior to need
Means of Achieving Resource Adequacy	• Capacity market with back-stop utility build (never triggered, to date)	• Capacity market

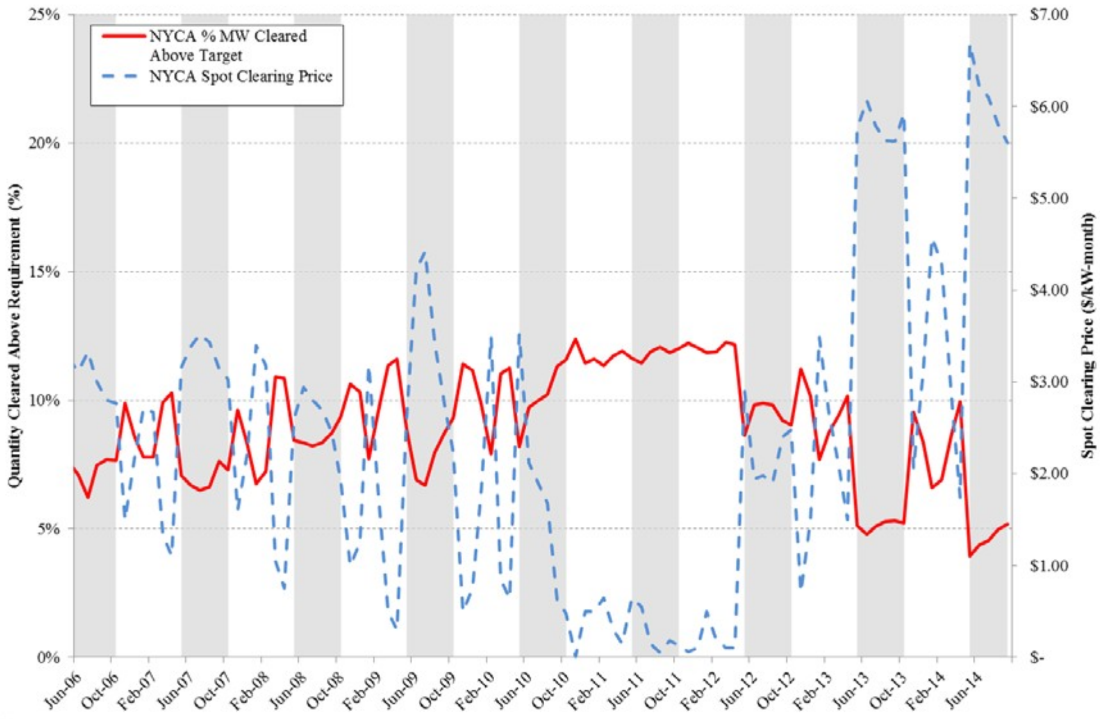
Proposal," October 7, 2014.

[14] Specifically, we evaluate a forward market design construct similar to concepts first reviewed by the NYISO and stakeholders in 2009, including a three year annual forward market construct, with annual reconfiguration auctions leading up to the delivery year. For example, See David Lawrence, "Forward Capacity Market – Advisory Vote", NYISO Business Issues Committee Meeting, June 10, 2009. See also ICAP Working Group meeting materials for March 19, 2009. Importantly, the scope of our analysis focused on basic differences between spot and capacity market constructs. For example, we did not attempt to evaluate further detailed variations on potential capacity market designs or constructs, such as partial capacity market auctions (e.g., a 50 percent auction, or auction with a small-percentage hold back).

2. NYISO Resource Adequacy Conditions and ICAP Market Outcomes

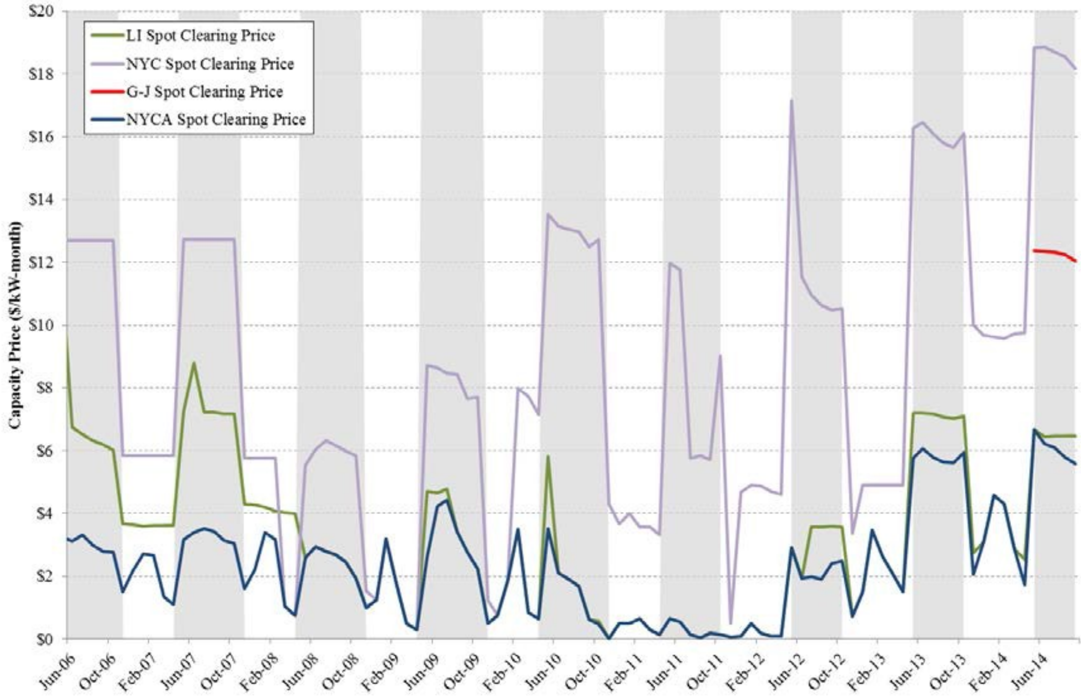
Since its inception, NYISO's planning and market structure has maintained resource adequacy through a combination of in-region resource development, demand response, imports/exports, and regulated utility transmission development. As shown in Figure 1, resource adequacy has been maintained, with quantities clearing above requirements despite significant variation over time and across capacity zones in market clearing prices, which are shown in Figure 2. However, the quantity of excess resources has fallen in recent years to the lowest level since 2006, with excess resources falling below 5 percent in 2014.

Figure 1: Cleared Quantities Above Installed Reserve Margin and ICAP Price



Notes:
[1] Shaded periods are summer months.

Figure 2: NYISO ICAP Prices by Zone, 2006 to Present

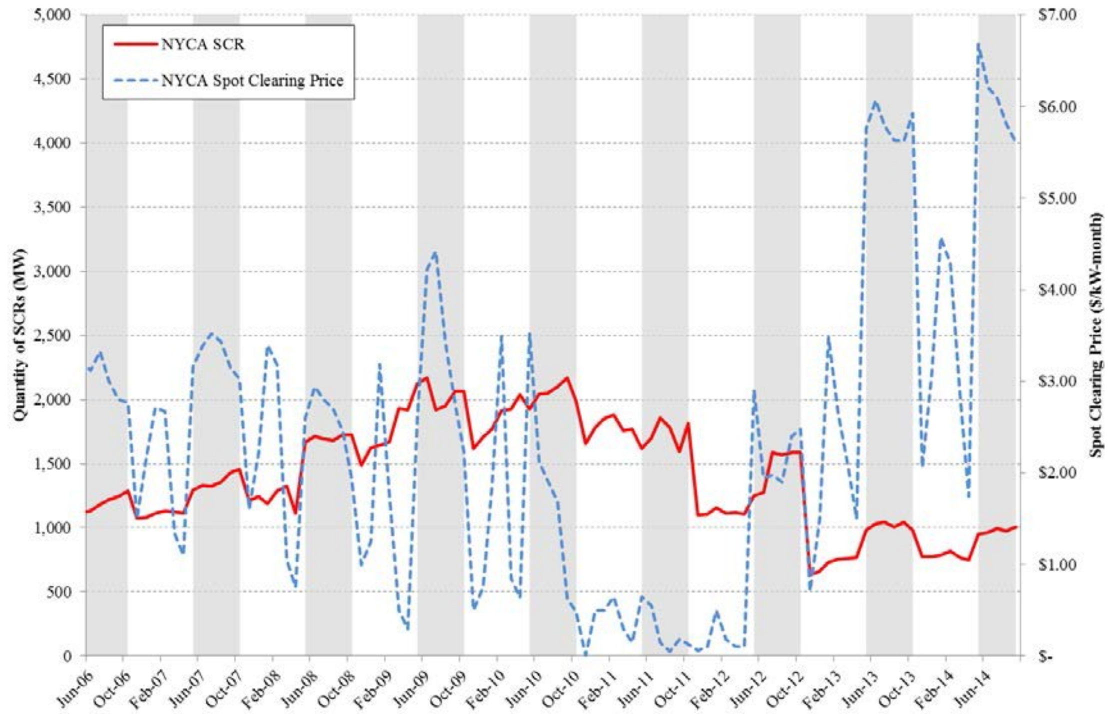


Notes:
[1] Shaded periods are summer months.

The supply of demand response in the NYISO market has varied over time, particularly as program implementation has changed in recent years. Figure 3 illustrates the change in demand response, as reflected by Special Case Resources, from 2006 to present. From 2006 through 2010, demand response grew gradually from roughly 1,000 MW to over 2,000 MW. At its peak, demand response represented approximately 6.5 percent of total procured capacity. Since 2010, demand response has gradually declined to just over 1,000 MW of capacity.[15] At present, demand response supplies 3.2 percent of UCAP requirement in NYCA, 3.6 percent in NYC and 2.5 percent in Long Island.[16] This decline in demand response resources reflects a combination of factors, including modified calculations for load baselines against which response is measured and new performance and eligibility requirements.[17]

[15] NYISO, "NYISO 2013 Annual Report on Demand Response Programs," http://www.nyiso.com/ViewerDocuments/Filing/Filing820/Attachments/Attachment%20I%20PUBLIC.pdf.
[16] Potomac Economics, "2013 State of the Market Report for the New York ISO Markets," May 2014, page A-162.
[17] Potomac Economics, "2013 State of the Market Report for the New York ISO Markets," May 2014, page A-162.

Figure 3: Demand Response (SCR) Supply in the NYISO ICAP Market



Notes:
[1] Shaded periods are summer months.

Resource adequacy in the NYISO reflects the net trade of capacity between NYISO and neighboring regions, including imports into NYISO and exports from NYISO. The NYISO borders four system operators. Two neighboring regions, ISO-NE and PJM, operate mandatory forward capacity markets, while the other two regions, IESO and HQ, do not currently operate mandatory forward markets. IESO is currently undertaking an investigation to determine whether its markets should move to a mandatory capacity market.[18] As shown in Figure 4, NYISO has historically been a net importer of capacity, with the exception of a small net export position in certain winter months. This net import/export position reflects the net effect of positive imports and positive exports. NYISO typically is a net importer of capacity from HQ and PJM, a net exporter to ISO-NE and currently has no mechanism to trade capacity with IESO.[19]

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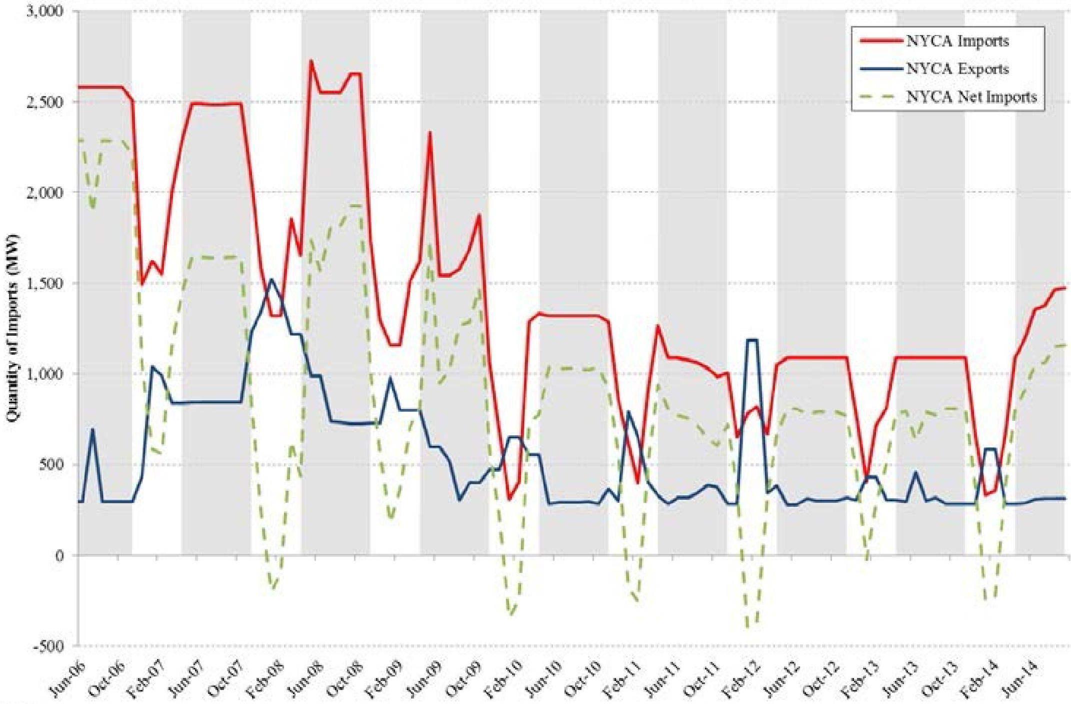
[18] IESO, "Backgrounder, Capacity Markets for Ontario," March 27, 2014, http://www.ieso.ca/documents/consult/Capacity_Market-Backgrounder.pdf.
[19] Potomac Economics, "2013 State of the Market Report for the New York ISO Markets," May 2014, page 44.

Figure 4: NYISO Capacity Imports and Exports



Notes:
[1] Shaded periods are summer months.

3. Resource Decisions in the NYISO

NYISO's ICAP and CSPP structures accommodate the development and operation of resources under a range of financial arrangements, including market-based merchant resources and resources supported by contracts with government agencies (such as the New York Power Authority (NYPA)) and regulated utilities, subject to New York Public Service Commission (PSC) approval. One motivation for reviewing potential changes to the capacity market structure arises from the fact that in recent years, many such arrangements have developed in support of new and existing resources. Table 2 provides some examples of selected recent and proposed changes in resource status. These arrangements involve a variety of circumstances, including Reliability Support Service Agreements signed in response to reliability concerns, bi-lateral long-term agreements for capacity, previously mothballed units that have returned to service, and other arrangements. The reliance in New York on these arrangements differs from the other eastern markets, which have greater reliance on market-based entry, except where vertical integration remains and self-supply is permitted.[20] For example, in contrast to other northeast states, New York distribution utilities are permitted to enter into long term bi-lateral agreements with power suppliers to meet their resource adequacy targets.[21] These

[20] In ISONE and PJM, self-supply is typically limited to historical arrangements or load serving entities (LSEs) in regions without retail competition, such as Virginia.
[21] NYISO Installed Capacity Manual, Section 2.1

arrangements can include agreements with longer durations than those permitted in many other states.[22]

Similarly, the NYISO market allows mothballed resources to return to service when economic conditions are more favorable. These resources contribute to the resource adequacy and are tracked as part of the NYISO long-term planning process. For example, in 2014, both Danskammer and Selkirk announced that they would return to service. Selkirk, in particular, had only announced its intent to mothball in March 2014.

The NYISO implements buyer-side market mitigation to ensure that any contracts do not provide above-market support of resources in a way that could distort capacity market prices away from efficient levels needed to attract and sustain sufficient resources. At present, such buyer-side mitigation is limited in at least several respects. First, there is currently no mitigation outside of certain zones (Zones G to J). Second, mitigation within Zones G to J may not fully mitigate the effect of below-market entry. In particular, the NYISO rules require that a unit subject to mitigation will have an offer floor set at 75 percent of mitigation net CONE, even if the resource's actual costs are above this level.[23] If costs are actually higher, mitigation would fail to set prices at a level comparable to the prices that would have prevailed had the resource entered without the contractual support. Third, current buyer-side mitigation rules are limited to new capacity resources or to the reactivation of generators that have been out of service for five years or more.[24]

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[22] Many states rely on procurement of a standardized full requirements service for fixed durations that range from one month to as much as three years, but typically not longer.

[23] Mitigation net CONE is defined as the annual reference requirement for the demand curve peaking unit, adjusted for the proportion of excess capacity in a given capacity zone. See NYISO Market Administration and Control Area Services Tariff Attachment H.

To address this issue, Potomac Economics has recommended that the offer floor be set to the lower of unit net CONE or 100 percent of the mitigated net CONE price. (Potomac Economics, 2013, page 96).

[24] NYISO Market Administration and Control Area Services Tariff, Section 23 Attachment H, Market Power Mitigation Measures.

Table 2: Selected Recent Resource Changes

Resource/Project	Contractual Counterparty	Year of Decision	Description
Astoria Energy II	NYPA	2011	• 20 year PPA, used in part to replace retirement of Poletti Power Project
Bayonne	Direct Energy Zone J Tolling	2012	• Tolling Agreements with Direct Energy (for 62.5% of output, tenors through 2022) and Zone J Tolling (37.5% capacity)
Caithness	LIPA	2009	• 20 year PPA
Cayuga	NYSEG	2014	• RSSA for Units 1 and 2, 2014-2017
Danskammer	Transfer of Ownership, Helios Capital	2014	• Repowering of existing resource • PSC approval of ownership transfer • Contract with Central Hudson Electric & Gas
Dunkirk	National Grid	2013 and 2014	• RSSA, Unit 2, 2013-2015 • Repowering 3 units to meet local reliability • Long Term Contract (10 years)
Ginna	Rochester Gas and Electric	2014	• RSSA, 2015-2018
Hudson Transmission Project	NYPA	2006, 2012	• Long-term bilateral contract
Indian Point Contingency Plan	?	?	• RFP for solutions in the event of a closure of Indian Point
Linden Cogeneration	Con Edison	1992	• 25 year PPA through 2017
Selkirk I and II		2014	• Announced and withdrew intent to mothball

C. Analytic Approach

Our approach to evaluating a potential change in capacity market structure for the NYISO focuses on identifying differences between the current SM structure and a potential FM structure from the perspectives of (a) reliability, (b) economic and market effects, (c) administrative costs, and (d) market clearing outcomes and impacts. We evaluate potential impacts using multiple approaches, including simulation of differences between market structures using an AG-developed capacity market model and a review of lessons learned from past wholesale market outcomes (in NYISO and other regions), the economic principles of market design (informed by actual market performance) and the potential administrative costs to implement a new capacity market structure.

The goal in combining both qualitative assessment and quantitative modeling analysis is to provide the NYISO and stakeholders with a complete picture on the potential impact of moving to a forward market structure, considering economic costs and benefits, reliability obligations, regulatory and market realities, and practical/administrative constraints. Importantly, our focus is *not* to identify the theoretically optimal electricity market structure, or to establish first principles to guide the formation of new wholesale market structures from scratch. Instead, we take as a given the current New York economic, regulatory and legal circumstances and constraints, and provide observations on the value and potential impacts of moving to a forward capacity market structure from where we are now.

Currently, electricity markets have been neither easy in principle, nor particularly smooth in practice. In every electricity market region, the design of electricity markets reflects a combination of factors, including complex technical design challenges, a complex array of jurisdictional disconnects and regulatory constraints, design processes governed in part through negotiation among disparate, competing interests, and inherent challenges associated with the lumpiness of major investment cycles and the inability to store product to any meaningful extent. As a result, regional models differ in many important respects, even when built upon a common core of location-based, security constrained energy markets.

The diverse interests of NYISO, New York State, and the region's electricity market stakeholders means that no analysis can provide *the* answer to whether or not New York should move to a forward market structure. One's conclusion on the question is highly dependent on the entity's goals, financial interests, and/or industry perspective. Is the specific goal or interest to minimize customer costs, or minimize customer risks? Maximize power system reliability? Minimize administrative burdens? Alter demand, change the resource mix, or otherwise achieve specific energy or environmental policy goals? Meet state and local economic development interests? Manage specific operational challenges? Or various optimal combinations of the above objectives? The answer NYISO may give – based on their reliability mandate and market efficiency and competitiveness objectives – is likely to differ from that of New York state, consumer and other load interests, generating asset owners, transmission and distribution utilities, new project developers, and energy/environmental policy interests.

Our analysis is thus structured to provide as much information as possible to inform the viewpoints of those engaged in considering potential market changes. We focus on the differences between the current market structure and a specific forward market design in the current NYISO context, and highlight those factors or considerations that seem to most significantly influence potential outcomes. In order to do this, we combine a model of the capacity market in NYISO with comparative analysis of market structures, quantification of administrative costs, and qualitative evaluation of competing market design features in the NYISO context. Specifically, the analysis (described more fully in subsequent sections) contains the following:

- ***A capacity market model*** structured to compare market outcomes in a future year (2020) under (a) the current SM structure, and (b) a FM structure. The model includes supply curves of unit- specific offers based on resource net going forward costs considering fixed and variable costs, capital expenditures, development and performance metrics, and expected revenues from other wholesale markets. The full NYISO market is modeled, including demand, system infrastructure, and unit-specific resource assumptions consistent with current NYISO planning documents and analyses. The model clears using the most recent NYISO demand curve parameters and the current market's nested zone structure. The differences between the current market and the forward market flow from different expectations of resource owners in consideration of the different costs and risks of forward versus spot market designs. Model results are tabulated as differences in clearing price and clearing quantity, revenues to generators, and costs to load, with all results presented under scenarios both with and without a 7-year lock-in for new entry. The model is run for a number of different scenarios and sensitivities to assess the sensitivity of model results to different demand, supply, and other assumptions/inputs.
- ***Estimation of the Impact on New Entry Costs of a Clearing Price Lock-In*** set for the purpose of the analysis at seven years (as recently approved for ISO-NE). Specifically, we research available history on the cost of debt and equity for new power plant investment across a variety of market constructs, lock-in periods (e.g., through either no lock-in/fully merchant vs. ten-year contractual arrangements), and asset owners, and develop a range of impacts on the weighted average cost of capital (WACC). The difference in WACC flows through our model as differences between the SM and FM structures in (a) the net CONE behind the assumed zonal demand curves, and (b) the offers by new resources seeking to enter the market. As discussed below, our results do not attempt to model any strategic bidding behavior on the part of new resources. Instead, we use adjusted estimates for net

CONE of both CT and CC technologies, based on the current demand curve reset model.[25] Our model allows for new entry by both technologies.

- ***Comparative Evaluation of Historical Market Outcomes*** to consider the potential impact of alternative market designs, price expectations, and changing resource and economic circumstances on the outcomes of capacity markets and the implications of disparate market designs across neighboring regions.
- ***Analysis of Key Market Design Considerations*** based on economic market-design principles and market design evaluations in the context of NYISO's market and other competitive U.S. wholesale markets.
- ***An Administrative Cost and Burden Assessment*** based on research into the cost to administer NYISO's current capacity market structure versus what would be needed in a forward market structure, including in part, an evaluation of the resources needed to implement forward market structures in neighboring regions (ISO-NE and PJM).

In the sections that follow, we proceed as follows. First, we describe in full our approach to quantitatively modeling differences in market outcomes that would flow from moving from the current SM structure to a FM structure, including a summary of the results from this analysis. Next, we present of evaluation of the two design decisions being considered – a forward market and a price lock-in – given the results of our quantitative analysis and the many other factors described above. With our evaluation, we also briefly consider alternative approaches to achieve the objectives of some of the key potential FM design features (e.g., notification of unit retirement, and the term of any optional new resource lock-in). Finally, we provide a summary of our findings and conclusions, and several appendices that contain greater detail on a number of modeling assumptions and approaches.

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[25] Specifically, we use the Demand Curve model developed by NERA and utilized in the 2014-2017 Demand Curve Reset process. These models are publicly available on the NYISO ICAP Documents and Resources portal, here: http://www.nyiso.com/public/markets_operations/market_data/icap/index.jsp

III. MODELING OF SPOT MARKET AND FORWARD MARKET DIFFERENCES

A. Purpose and Overview of the Model

As part of this assignment, Analysis Group developed a simulation of the NYISO capacity market, with representations of both the current spot market structure and a hypothetical forward market structure. By comparing spot and forward market outcomes, important differences between a forward and spot market design can be illustrated. Market outcomes evaluated include market-clearing prices, clearing quantities, and annual costs to load by zone. To simulate market clearing, the model orders competitive supply bids based on expected offer costs (calculated broadly as expected fixed and variable operating expenses net of expected energy and ancillary services revenues) and solves for the market-clearing quantity and price given the relevant user-defined demand curve.

The model's flexibility allows the analysis of a wide range of scenarios, reflecting different assumptions related to the demand curve, existing resource supplies, and resource decisions related to new entry or generator retirement. In this report, to highlight differences between spot and forward market structures, multiple scenarios are evaluated reflecting different levels of retirements and new resource entry, as well as differences in how forward and spot markets respond to load forecast uncertainty.

The model is not intended to capture and quantify all aspects or differences between a forward and spot market. A comprehensive treatment of issues and tradeoffs between a forward and spot market design is provided in Section IV. The goal of the present analysis is to provide a balanced assessment of key design issues through quantification, where possible, of the likely magnitude and direction of these design issues.

The current model provides a snapshot of a single future year (2020).[26] While the model includes data on a unit by unit basis, it is not designed to forecast or predict individual unit decisions such as future retirements or new entry. As a single-year model, it does not account for all dynamic, multi-year economic factors, although some multi-year impacts are addressed through complementary review and analysis. The capacity market model is based on the current NYISO spot market demand curve, and includes individual generator specific costs and revenues, based on publicly available data. The foundation for the model is the 2014 NYISO Congestion Assessment and Resource Integration (CARIS) GE MAPS production simulation results and load forecast data from the 2014 Gold Book.

With this foundation and quantitative structure in place, adjustments to both the demand curve and supply curve are made to account for changes in market structure. First, we consider a switch to a forward market structure with a three year advanced procurement. For the supply curve, changes under a forward market include an increase in offer prices for existing units to account for the increased uncertainty and commitment associated with the three-year forward obligation. No

[26] While our analysis reflects outcomes for one study year, the findings about the differences in market outcomes between a forward and spot market structure are not generally sensitive to the particular year modeled.

changes to the demand curve are assumed.[27]

Next, we consider the addition of a price lock-in to the forward market structure. Under a price lock-in, a reduction in finance costs for new resources is assumed that affects both the demand curve and the supply curve. For the demand curve, the likely impact of a 7-year lock-in on financing costs is estimated, including expected changes to both the cost of debt and the cost of equity. Because a price lock-in provides additional certainty for a portion of generator revenues over a fixed period, revenue uncertainty is reduced, which may lead to lower financing costs as compared to a market design without the lock-in. The 2013 NYISO Demand Curve Reset model is used to calculate the impact of the change in financing on the net CONE for the reference unit in each zone.[28] Updated reference prices are then used to develop demand curves for the forward market with a 7-year price lock-in.

The assumption that the 7-year price lock-in, by lowering finance costs, would shift the demand curve reflects current market rules, in which the demand curve depends on net CONE. Note, however, that the change in the cost of new entry would not be expected to change the underlying value placed on resource adequacy by load. Thus, the demand curve changes assumed reflect the processes defined in current market rules, not a change in underlying demand.

This section begins with a description of model logic and key model parameters. It serves two purposes. One purpose is to describe the model's assumptions and structure. The second is to describe the adjustments to supply and demand curves – and resulting market impacts – that would likely occur from the two design features being evaluated. Model results and parameter specifications are presented below, including a detailed sensitivity analysis of results.

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[27] If administrative net CONE was adjusted to account for factors such as increased uncertainty and deficiency risks under a forward market, then the switch to a forward could lead to a change in the demand curve. Because the current Demand Curve Reset model does not account for such factors, we do not assume any adjustment in the demand curve in our analysis. This is also consistent with both ISO-NE and PJM, neither of which include additional risk adders in their administrative net CONE calculation. In addition, we assume that the one-year price lock-in available under a forward market (but not a spot market) would not have a meaningful impact on financing costs.

[28] During the 2013 Demand Curve Reset Study, the NYISO Board of Directors engaged Brattle/Licata to conduct an additional review of the economic and technical feasibility of using an F class frame with SCR as the reference unit. Brattle/Licata worked with NERA/S&L to modify the earlier analyses. All models and documentation are publicly available on the NYISO website. See ICAP Reference Documents, available: http://www.nyiso.com/public/markets_operations/market_data/icap/index.jsp.

B. Scenarios and Model Results

1. Model Logic

The capacity market simulation model is designed to calculate market-clearing prices and quantities given a supply curve reflecting current resources in NYCA and demand curves reflecting the current NYISO ICAP market.

Market-clearing prices and quantities are calculated based on current market clearing rules in the NYISO spot market and assumed rules under a hypothetical forward market, designed to reflect typical rules in existing forward markets. When there is sufficient supply to clear demand, the clearing prices and quantities reflect the intersection of the supply and demand curves. When the supply is below the demand curve the market clears at the vertical intercept between the quantity of supply and the demand curve. We assume that the same set of existing resources offer into both the forward and spot market, unless indicated otherwise in specific scenarios.

The model includes the current NYISO nested construct of capacity zones.[29] Results are provided for each of four zones: the G-J locality (G- J), New York City (NYC), Long Island (LI) and NYCA. Aggregate results reflect outcomes across the entire New York Control Area (NYCA). Nested Capacity zones follow hierarchal pricing rules, such that prices in a nested zone must be greater than or equal the price in the broader zone.[30] Within the model structure, units that clear in a nested zone are included as procured capacity in the broader zone(s).[31]

Consistent with the current NYISO spot market, generator bids are fully rationable. That is, if the cumulative supply of resources including the marginal unit crosses the demand curve, then the auction clears only the portion of the marginal unit needed to clear supply and demand. If the resource is offered into a sub-zone, then the remainder of the capacity is bid into next-level-up zonal auctions at its offer prices. Any excess capacity within NYCA does not clear the market.[32] Appendix I provides additional detail.

Within the forward market, when resource entry occurs, we assume the supply of new resources is sufficient to clear the market without excess capacity, thus avoiding the complications associated with “non- rationable” bids, which are permitted in the ISO-NE and PJM forward markets.

The model reflects supply and demand curves that are described in greater detail below. The model incorporates the full set of changes to supply and demand curves that would be anticipated

[29] NYC (Zone J) is nested in G-J, and both G-J and LI (Zone K) are nested in the NYCA.
[30] For example, the clearing price in Long Island cannot be lower than the clearing price in NYCA.
[31] For example, capacity in NYCA reflects capacity to meet the rest-of-state (Zones A-F) amounts given capacity already procured in Zones G-J, NYC and LI.
[32] If the supply curve crosses the demand curve in between two unit bids, the crossing point is defined by a vertical line from the lower bid up to the demand curve. This represents the minimum price necessary to ensure that all capacity bids below the curve clear.

from a shift to a forward market. The combined effect of these changes drives the observed differences in prices and quantities between a forward and spot market.

2. Scenarios

To better understand potential outcomes of a shift to a forward market, multiple scenarios reflecting a variety of different market circumstances are evaluated. The choice of scenarios reflects input from the NYISO, as well as its market monitor, Potomac Economics.[33] For each of these scenarios, the forward market is modeled with and without a 7 year price lock-in. These scenarios include:

1. *No New Entry*: This scenario assumes no new resources enter in either the spot or forward market. Differences in clearing prices, quantities, payment to generators, and annual cost to load are driven entirely by changes to the demand curve (in cases with a price lock-in) and changes to the existing supply curve.
2. *New Entry at net CONE:* New entry is included in the supply curve, with new entry units bid as price takers ($0/kW-mo) in the spot market and bid at values equal to the estimated net CONE from the NERA/Brattle demand curve reset study in the forward market. This includes bid values for both combined cycle (based on an SGT6- PAC5000F(5) unit) and the reference unit combustion turbine technologies.[34]

   The total quantity of new entry included in the spot market is such that the estimated clearing price is approximately equal to net CONE. That is, new entry is clears in the market and displaces existing capacity until the clearing price is approximately equal to net CONE. In contrast, in the forward market, new entry quantity is equal to the amount that clears the market, assuming a bid value equal to net CONE. Because assumptions for the 7-year lock-in affect net CONE, we estimate clearing quantities for each of the four sensitivities.
3. *All Coal Retirements with No Spot Market New Entry:*[35] All remaining coal units retire,[36] with new entry in only the forward market. New entry in the forward market enters at the

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[33] Analysis Group chose the year 2020 because it represents the earliest possible year that a forward market could be expected to become operational, assuming a two-year development period with a three forward procurement held in 2017. As we discuss in Section IV.D., based on the experience of ISO-NE and PJM, this appears to be an aggressive development schedule. Modeling the earliest possible year also helps reduce the effect of forecast uncertainty - for example, with load growth or inflation expectations - on model outcomes.

[34] The demand curve reset study includes estimates for technology and region specific energy and ancillary services revenues. These values are used to shape the unit specific net CONE for each region. For the purposes of this analysis, we did not model the impact of new entry units on the expected energy and ancillary services revenues of existing resources through separate GE MAPS production simulations.

[35] This scenario is based on the NYISO 2012 Reliability Needs Assessment, which modeled an all coal retirement scenario based on an extensive discussion with stakeholders. The scenario is not designed to forecast market outcomes, and Analysis Group recognizes that market dynamics can affect resource retirements decisions. For example, the retirement of one or two coal units would tend to raise capacity market clearing prices, which may provide additional revenue support to the remaining coal units.

[36] This includes: Huntley 67 and 68, Jamestown 5 and 6, Somerset, and Cayuga 1 and 2. This represents approximately 1,400 MW of summer capacity in NYCA.

reference price (net CONE). Because not all coal units would have cleared on the supply curve (offer prices above the estimated clearing price), less than the full 1,439 MW of retired capacity is replaced by new entry. In the forward market, new entry quantities range from 631 MW (assuming no lock-in) and up to 1,163 MW (assuming a lock-in, at the upper bound of estimated financing impacts). In contrast to the new entry at net CONE scenario, no new entry is included in zones G-J, NYC, or Long Island.

4. *All Coal Retirements with Spot Market Reliability Support Services Agreements:* All remaining coal units retire, with new entry in the forward. In the spot market, 50 percent of coal units are assumed to be retained through Reliability Support Services Agreements (RSSA), with no additional new entry.[37] RSSA coal units bid into the capacity market as price takers ($0/kW-mo), but are included in total cost to load calculations. RSSA payments are indexed to recently approved RSSA agreements for both the Cayuga and Dunkirk facilities.[38]

5. *Higher than Expected Load Growth*: Load obligations in the delivery year 2020 are 5 percent higher than forecast during the initial forward auction, requiring rebalancing in subsequent reconfiguration auctions. In the delivery year, both the spot market and a forward market procure the same target quantity of capacity. In the spot market, all supplies are purchased through a spot market auction. In the forward market, supplies are procured through an initial forward auction and a subsequent balancing auction to adjust the initial procurement to the final requirement. In this case, additional capacity needed to fulfill the larger requirements (i.e., to account for the 5 percent growth in load) are procured through an auction based on remaining supplies that did not clear in the initial forward market. Appendix III provides additional details. This sensitivity is based on the No New Entry scenario described in 1 above. For both the SM and FM, the IRM/LCR is held constant (at 2014 values).[39]

6. *Lower than Expected Load Growth*: Load obligations in the year 2020 are 5 percent lower than forecast during the initial forward auction, requiring rebalancing in subsequent reconfiguration auctions. As with the prior scenario, both the spot market and a forward market procure the same target quantity of capacity. Excess quantities purchased in the initial forward auction are assumed to be sold at the new estimated clearing price in the reconfiguration auction. The total payment to generators and cost to load is equal to the

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[37] This scenario is not intended to suggest that a forward market may fully alleviate the need for local reliability determinations and out of market contracts. The issue of local reliability, including zonal constraints, in a forward market is discussed more broadly in Section IV.B. In contrast, the purpose of this scenario is to provide a bound to potential differences in market structures. Here, RSSAs are viewed more generally to support adequacy targets. The NYISO planning process defines system reliability in terms of both resource adequacy and transmission security. The NYISO may trigger a gap solution as part of its Comprehensive Reliability Plan. See NYISO Open Access Transmission Tariff, Attachment Y, Section 31.2.10.

[38] See recent NY PSC Orders in cases 12-E-0136 and 12-E-0400.

[39] In practice, the final demand curve reference requirement is a function of both the load forecast and the IRM target. A change in either parameter, while holding the other constant, leads to a change in the final absolute MW reserve requirement. In operation, both parameters are adjusted annually to arrive at a final requirement, and offsetting changes can be made in the IRM to account for changes in load forecast.

obligations from the forward auction minus the rebalancing revenues. To the extent that market participants are unwilling to sell-back obligations, results would understate quantity and costs. Appendix III provides additional details. This sensitivity is based on the No New Entry scenario described in 1 above.

In addition to these scenarios, Analysis Group conducted an evaluation of the capacity market "uplift" payments available to new entry under a 7-year lock-in, under various assumptions of future capacity market prices. These results are presented separate from individual modeling results.

C. Supply Curve

The supply curve and individual unit bid estimates were developed based on the 2014 Preliminary CARIS II Base Case, which is used by the NYISO in its long-term reliability planning process.[40] CARIS II results used in our analysis include annual unit-level estimates of energy production, energy market revenues (including ancillary service payments and daily uplift), and total variable operating costs, including fuel expenses, emission costs, and start-up costs.[41] Notable assumptions in the CARIS II Base Case that impact the 2020 modeling year include:[42]

1. Transmission Owner Transmission Solution (TOTS) projects are in-service;
2. Cayuga 1 &2, Selkirk 1&2, and Bowline 1 & 2 are in service, with the Danskammer units modeled out-of-service;
3. Market Based Solutions from the 2012 CSPP are in-service, which includes 500 MW of capacity in 2018 and 2023 at Astoria; and
4. 210 MW of generic gas turbines are installed at Barrett Station (in 2016) for resource adequacy assurance.

In addition to the CARIS II assumptions, Dunkirk Station is assumed to repower on natural gas in 2016.

The NYISO production simulation results were combined with additional information to calculate unit specific bids in the spot market as:

$$Offer = \frac{(FOM + VOM + T + I + E + NRC) - EAS}{UCAP * 12}$$

[40] The 2014 Preliminary CARIS 2 Base Case results were presented to stakeholders at the June 30, July 24, and August 7, 2014 Electric System Planning Working Group meetings and the August 13, 2014 Business Issues Committee.
[41] This information is developed from the GE MAPS production simulation results used in the CARIS 2 Base Case.
[42] See Duffy, T. 2014 Preliminary CARIS 2 Base Case Results, Presented to Electric System Planning Working Group, June 30, 2014. Available: http://www.nyiso.com/public/markets_operations/committees/meeting_materials/index.jsp?com=bic_espwg

Where:

- Offer is priced in ($/kW-month)
- *EAS* = energy and ancillary services Revenue, including daily uplift;
- *FOM* = fixed operations and maintenance expenses;
- *VOM* = total variable operating and maintenance expenses, including variable operating costs, fuel, emissions, and start-up costs;
- *T* = annual property taxes;
- *I* = annual capital expenditures for investments;
- *E* = unit-specific estimate of potential environmental retrofit expenses (select generators); and
- *NRC* = unit specific estimates of potential retrofit expenses for select nuclear generators.

Offers calculated using the above formula are used in developing a supply curve for capacity offered into the forward and spot capacity markets. UCAP capacity was combined with capacity obligations for external capacity rights, Special Case Resources (SCRs), and Unforced Deliverability Rights (UDRs). Data inputs for unforced capacity (UCAP), fixed operations and maintenance (FOM), taxes (T), annual investments (I), environmental retrofits (E), and nuclear costs (NRC) are described in Appendix I.

Figure 5 through Figure 8 illustrate the average proportion of these costs and revenues, on a region and technology basis for 2014.

Figure 5: Average Revenue and Costs, Select Technologies, NYCA

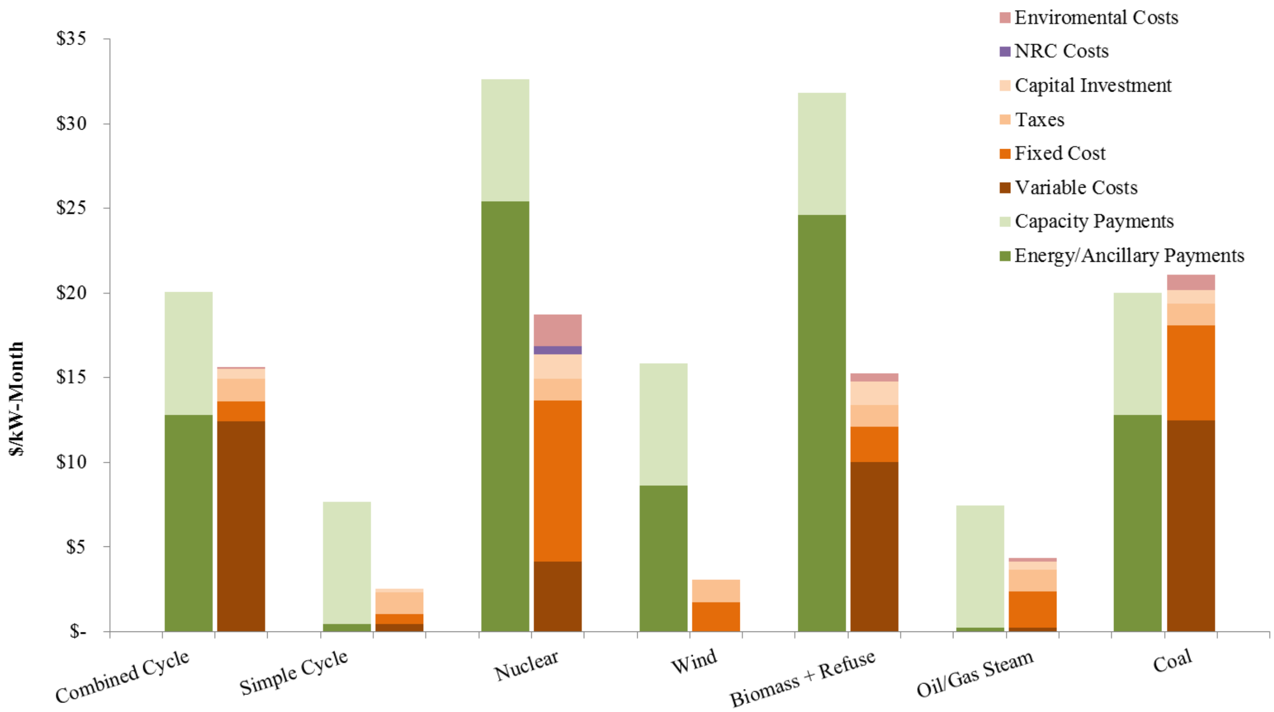


Figure 6: Average Revenue and Costs, Select Technologies, Long Island

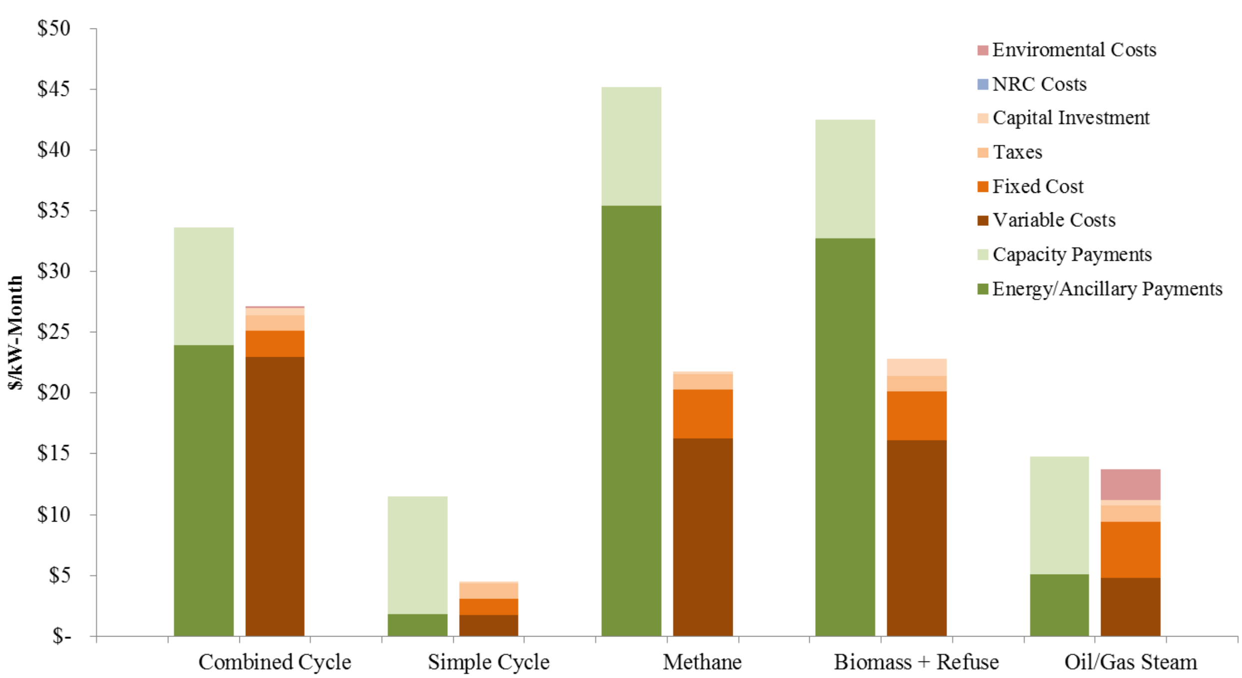


Figure 7: Average Revenue and Costs, Select Technologies, NYC

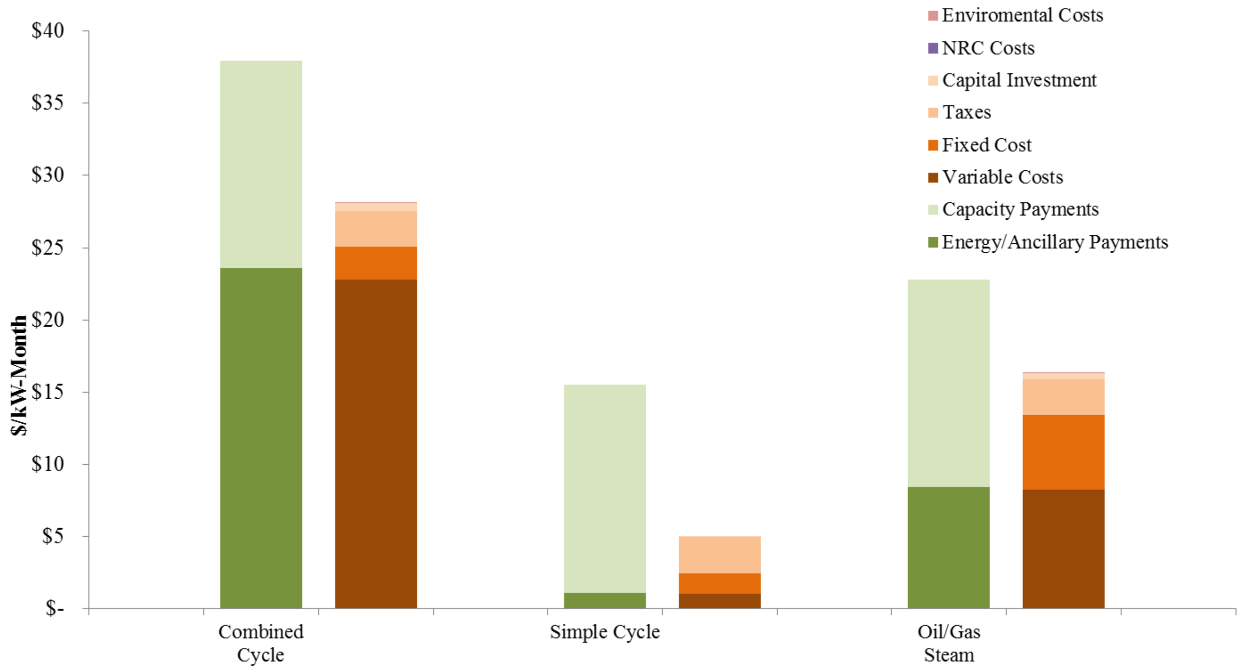
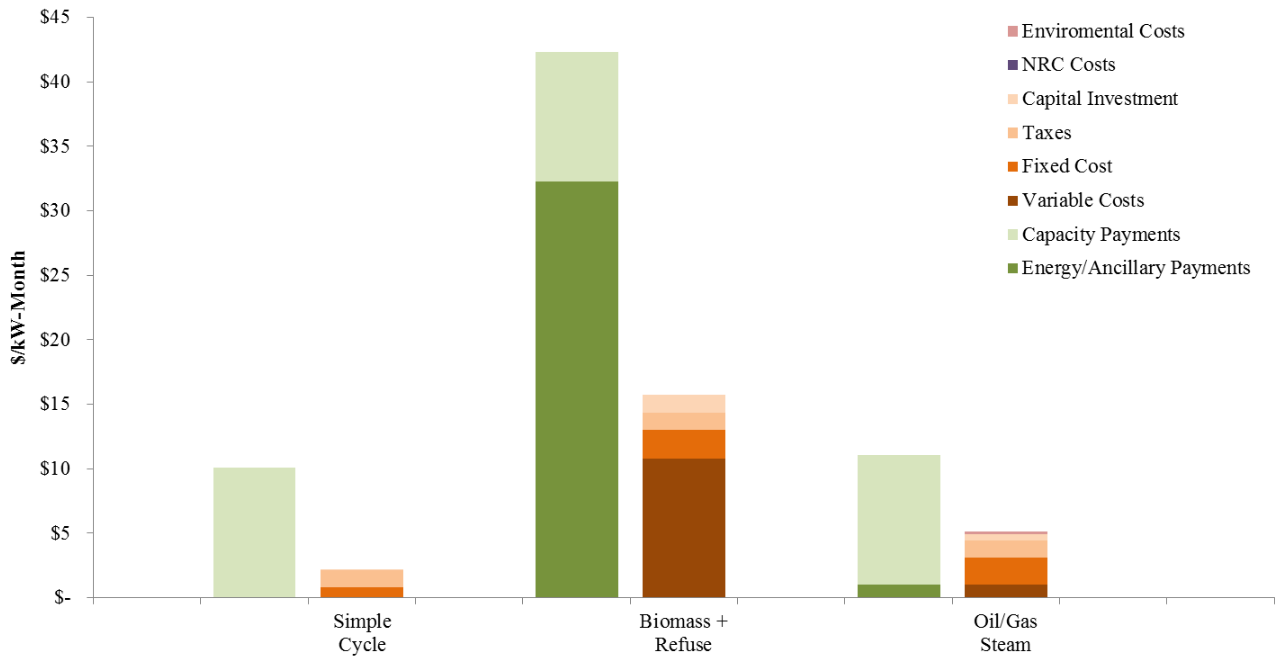


Figure 8: Average Revenue and Costs, Select Technologies, G-J[43]



[43] This figure excludes information for nuclear facilities in G-J to avoid individual identification of Indian Point Units 2 and 3.

1. Changes to Supply Curve from a Forward Market

Under a forward market, the NYISO would procure commitments for capacity three years prior to the delivery year. This commitment will create additional uncertainty for existing resources. As part of this exercise, we quantified the risk premium associated with both a commitment risk made three years forward and a deficiency risk related to the physical capacity obligation.

For existing generation resources, there are three types of economic impacts from the switch to a forward market:

1. *Reduced Optionality*. Reduced optionality represents the opportunity cost of limiting the ability to take certain actions in the future (or raising the costs of pursuing those actions) by committing resources three years forward. For example, resources committed in a forward market have less flexibility to retire, mothball or supply capacity to another market. This option is more valuable when there is greater uncertainty (e.g., when many resources face potential retirement due to environmental regulations or market conditions).
2. *Deficiency Payment Risk*. With a forward market, there is a risk the resource is not developed in time for the delivery year and the resource would incur deficiency costs. Such costs would occur if owners could not find replacement capacity and faced deficiency penalties, or if replacement capacity was procured at a price greater than the price of the original capacity supply obligation (CSO) in the forward procurement auction. However, if the price of replacement capacity was less than the original auction price, then the owner would earn a windfall by selling out its position.
3. *Price Stability*. To the extent that forward prices are less volatile than short term spot markets, a forward market can reduce financial risk. Reduced cash flow volatility can reduce business cash flow volatility and provide other financial benefits.

Within the quantitative modeling, these economic factors are accounted for in two ways. First, we estimate the expected cost of deficiency risk given data on past resource operating performance and information on deficiency costs. Under the current NYISO tariff, the maximum deficiency penalty is set to one and one-half times the applicable market clearing price times the quantity of unforced capacity determined to be deficient. [44] However, deficiency costs are uncertain because resources can trade-out their obligation to other resources, potentially at lower cost. Moreover, the type of deficiency penalty mechanism under a NYISO forward market construct may differ from the NYISO's current SM deficiency penalty.

To account for deficiency payment risk, we increased offer prices assuming that each generator would bid as if it was the marginal unit (that is, its offer prices represent the applicable market clearing price), and deficiency risk is equal to:

[44] NYISO Installed Capacity Manual, Section 5.8.

$$Deficiency\ Risk\ (\$) = Outage\ Probability_{tech\ per\ year} * 150\% * Offer\ Price_{unit_i}$$

Under the existing NYISO tariff, existing generators face up to a penalty of one and one-half times the applicable market clearing price of the unforced capacity.[45] Here, we assume that each generator offers as if it were the marginal unit, and its offer price represents an estimate of its own expectation for market clearing prices.

To benchmark the annual probability of an unforced outage, we reviewed significant generator derates and forced outage retirements within the New York generator fleet for the period 2010-2014.[46] Within each year, the total quantity of derated MWs was compared to the total quantity of available MWs, on a technology basis. Over this time period, the maximum ratio for capacity derates was equal to 4 percent of total capacity for fossil steam turbines[47] and 2.4 percent for combustion turbines.[48] Appendix I provides additional details. Based on this analysis, the probability of significant outage was set to 4 percent for coal and oil/gas steam units, 2.5 percent for simple cycle units, and 1 percent for all other technology types.[49] Modeling results are presented for sensitivities using higher and lower values for the deficiency risk in Figure 26.

To account for the other economic impact of a forward market (lost optionality and financial value of price lock-in), the offer prices for all resources are increased by 10 percent of going forward costs, based on a review of similar provisions within ISO-NE and PJM. This represents a departure from the current going-forward cost definition defined by the ISO in Section 23.4.5.3 of the Market Services Tariff, which allows generators to bid all avoidable costs, including but not limited to mandatory capital expenditures necessary to comply with applicable federal or state environmental requirements. Since resources face new risks that do not exist in the existing spot market, these risks would likely be allowed for in a FM construct. Both ISO-NE and PJM allow resources to bid into their respective forward markets at values above unit specific avoidable costs. In New England, market rules allow resources to include a risk premium. In past years, this risk premium has reflected deficiency payment risk and replacement power cost risk, while the current tariff allows resources to offer risk

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[45] NYISO Installed Capacity Manual, §5.8 ICAP Supplier Shortfalls and Deficiency Payments.

[46] A significant derate was measured as a decline in summer capacity rating of 10 percent or 40 MW, based on reported capacity in the NYISO Gold Book. Retirements due to forced outages were identified through individual generator notices provided to the NYISO, which are publicly available through the NYISO website via the Planning Documents and Resources portal, here: http://www.nyiso.com/public/markets_operations/services/planning/documents/index.jsp.

[47] This value is for the 2012-2013 capability year and includes the retirement of Danskammer Units 1-6. In 2011-2012, derated capacity accounted for 3.5 percent of total steam turbine MWs, accounting for the loss of capacity at Roseton Unit 2 and Bowline Unit 2.

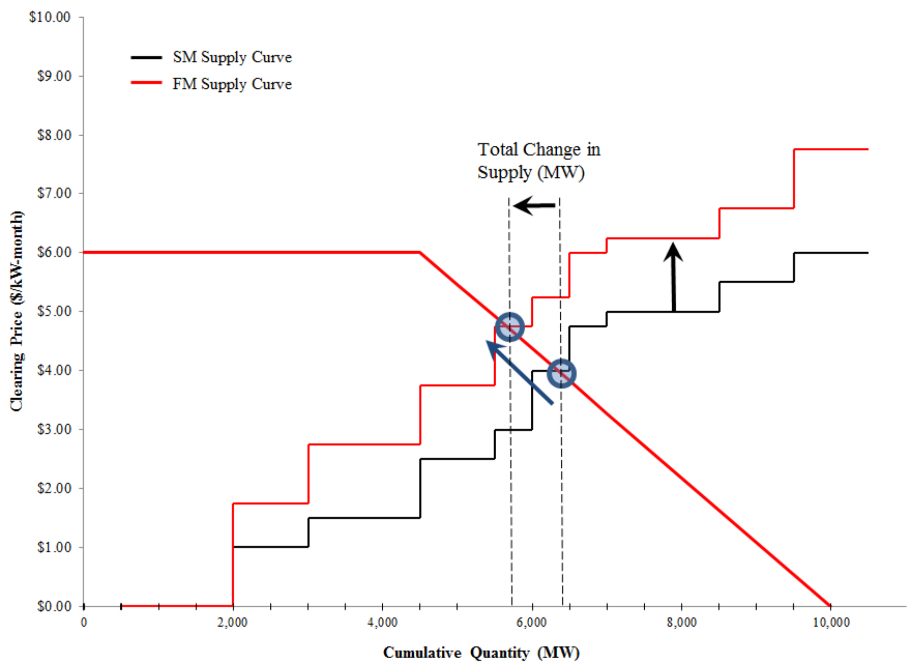
[48] This value is for the 2010-2011 capability year and includes the retirement of Ravenswood GT 3-4 and Barrett GT-07 and derates in capacity to 74th Street GT1, Ravenswood 04 and 07, Arthur Kill GT1, Glenwood GT 01, and Hudson Avenue units 4 and 5. Similarly, derated capacity for Jet Engine units was equal to 1.8 percent in 2013-2014 due to derates at Ravenswood 2-1, 2-2, 3-1, 3-2, 9 and 11.

[49] This risk is applied to all resources, but does not affect price taking resources (like wind and solar) that are estimated to bid in at $0/kW-mo.

premiums that can be quantified and analytically supports.[50] PJM currently allows resources to increase estimates of going forward costs by up to 10 percent to account for "understatement of costs."[51] PJM recently proposed to implement a "safe harbor" such that capacity performance resource offers may bid up to the Net CONE for its applicable region. Any offer up to the safe harbor will not be subject to mitigation based on the individual resource's Avoidable Cost Rate.[52] PJM estimated that the price of capacity for the 2018/2019 delivery year could be between 0.6 and 0.8 x net CONE without the proposed changes and be between 0.7 and 1.0 x net CONE with these changes.[53]

Combined, these quantified effects for deficiency payment risk and economic impacts increase offer prices for existing generation, which shifts the supply curve up. Absent any changes in the demand curve, the forward market supply curve intersects the demand curve at both a higher price and a lower total quantity of cleared capacity, as illustrated in Figure 9.[54]

Figure 9: Illustrative Supply Curve Shift, Accounting for Increased Commitment and Deficiency Risk



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[50] For auctions through FCA8, see Section III.13.1.2.3.2.1.2. For subsequent auctions, resources are permitted to include a "reasonable" risk premium, as defined in draft Section III.13.1.2.3.2.1.4. ISO-NE and NEPOOL, FERC Filings of Performance Incentives Market Rule Changes, Docket No. ER14-1050-000, January 17, 2014.
[51] PJM Open Access Transmission Tariff, Sections 6.4 and 6.8, Effective September 10, 2014.
[52] PJM Staff. PJM Capacity Performance Updated Proposal, October 7, 2014, at page 31.
[53] PJM staff estimated that the total cost of the program could be between $0.9 and $2 billion in the 2017/18 delivery year, after accounting for the energy market cost reduction for improved average EFORd rates. PJM Staff. PJM Capacity Performance Cost Benefit Analysis. October 23, 2014, at page 4.
[54] As discussed earlier, we assume that the administrative calculation of the cost of new entry would not incorporate these types of cost factors.

The shift to a forward market could also have cost implications for new resources. In addition to the deficiency payment risk identified above, the following economic factors – both of which lower new resource costs – also affect new generation resources:

1. *Reduced Price Risk from Competitive Entry.* With a forward market, competition between new resources occurs in the forward market, such that higher priced new resources are priced out and thus do not enter the market. As a result, a forward market can reduce the risk of excess new entry, as well as the corresponding decline in capacity prices, thus supporting the entry of new resources. By contrast, with the spot market, resources enter without information about other resources entering the markets and the extent to which new supplies are needed, particularly given potential resource retirements.
2. *One-year Price Lock-in*. With a forward market, prices are locked-in for the first year. Over a new resource's 20 to 40 year economic life, this additional price assurance likely has limited value. However, to the extent that there is serial correlation in prices (i.e., high prices in one year are likely to be followed by high prices in the next), the guarantee that a new resource will not enter unless the market clears at (or above) the resource's cost new entry in the first year may provide greater assurance that prices will be sustained at this level for several years into the future.

The switch to a multi-year price lock-in for new resources would not have any direct consequences for the costs associated with existing resources. However, a price lock-in would affect the costs of new generation resources. First, by reducing financial risk, a price lock-in would lower financing costs and thereby lower new entry costs. In Section III.D.3, we assess the potential impact from this change in financial risk. Second, a multi-year price lock-in potentially locks in prices at a level that is above the expected market price, thus providing new resources with an increase in expected revenues compared to a market with no price lock-in. There are many factors, such as the timing of new entry decisions and the timing of retirement decisions that affect the likelihood of such an outcome, and the magnitude of expected revenue gain, if any.

In our quantitative model, we account for changes in financing costs, as discussed in Section III.D.2, but we do not assume any increase in expected revenues from a price lock-in when determining the cost of new entry. Additional revenues in years 2-7 would offset necessary revenues in years 8-30, suggesting that on net, net CONE would remain unchanged. Therefore, this assumption does not affect our overall conclusions, particularly in the context of the many uncertainties (observed and unobserved) affecting the true cost of new entry.

D. Demand Curve

Within the capacity market model, sloped demand curves for future years are based on the current NYISO assumptions and specifications. Appendix I provides the full set of parameters used in our analysis. The demand curve is defined by three points and a cap, with different values for the summer and winter capability periods: [55]

- The monthly ICAP Reference Point price, equal to the net CONE for the demand curve reference unit, expressed in $/kW-month;
- The minimum Installed Capacity Requirement or Locational Installed Capacity Requirement by capacity zone, expressed in MW, such that the demand curve is equal to the ICAP reference price at the value of load equal to the peak load forecast multiplied by the respective Installed Reserve Margin (IRM) or Locational Capacity Requirement (LCR) value.
- The zero crossing point, defined as the point at which the demand curve crosses the x-axis and the marginal value of capacity is equal to $0/kW-month.
- The price cap is a horizontal line segment equal to 1.5 times the gross estimated levelized cost per kW-month to develop a new peaking unit.

The NYISO develops reference prices through the demand curve reset process, performed every three year in consultation with stakeholders and with the analysis of an independent consultant.[56] The reference price is set to the net CONE for an F-class frame with SCR (in zones G-J, NYC, and LI) and an F- class frame without SCR (in NYCA), escalated annually at 2.2 percent inflation. Net CONE includes expected energy and ancillary services revenues minus fixed and variable operating costs, including taxes, depreciation, and financing costs.[57] The reserve requirement is defined to meet a loss a load of expectation (LOLE) of one day in ten years (0.1 events per year), defined as:

$$\begin{aligned}&Reserve\ Requirement\ (UCAP\ MW)\\&\quad = Peak\ Demand * \left(1 - Translation\ factor_{ICAP/UCAP}\right) * IRM\ (or\ LCR)\end{aligned}$$

Peak demand is based on the system peak for NYCA and non-coincident peak demand in G-J, NYC, and LI, as defined in the 2014 Gold Book and IRM/LCR factors defined by the NYISO and the New York State Reliability Council.[58] The ICAP/UCAP translation factor represents the average

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[55] See, generally, NYISO ICAP Manual, Section 5.5. Monthly reference price values are adjusted to account for the summer and winter capacities of the reference unit. Winter demand curves are based summer peak demand forecasts, but are adjusted using a winter specific ICAP/UCAP translation factor. For the purposes of this analysis, all demand curves are based on the summer reference values. Holding this assumption constant between both the forward and spot market allows for a direct comparison of the differences between the two market structures. Section IV.C discusses the tradeoffs associated with an annual versus seasonal construct within a forward market structure.

[56] For a detailed description, see New York Independent System Operator Proposed Tariff Revision and Demand Curve Reset Filing, Submitted November 27, 2013 to Federal Energy Regulatory Commission, Docket No. ER14-000, and associated materials, available http://www.nyiso.com/public/markets_operations/market_data/icap/index.jsp

[57] As described in the body of the report, as part of this review, Analysis Group updated the financing assumptions embedded in the Brattle/NERA model and calculated additional reference prices for forward capacity market demand curves that account for a potential impact of a 7-year lock-in for new entry.

[58] IRM is set by the New York State Reliability Council using a probabilistic framework that accounts for generator

Equivalent Demand Forced Outage Rate (EFORd) value of the six most recent 12-month rolling average EFORds of all resources in a given locality.

A critical input to each demand curve reset process is the development of financial parameters, including the capital structure and cost of capital. In the 2014-2017 demand curve reset study, the reference unit was assumed to be developed by a merchant generator, assuming a 50/50 debt to equity ratio with the nominal cost of debt at 7 percent and the nominal cost of equity at 12.5 percent.[59] These findings were based on extensive feedback from stakeholders, a review of specific debt issuance for merchant generation companies, and the use of the CAPM cost of equity model. Levelized costs further account for income and property taxes, insurance and depreciation. Based on these inputs, the recommended pre-tax weighted average cost of capital (WACC) was a 9.75 percent on a pre-tax basis and 6.37 percent on an after-tax basis.

1. Changes to Demand Curve from a Forward Market

The two proposals under consideration – a forward market structure and a multi-year price lock- in for new capacity – both potentially affect the cost of new entry. If these proposals change the cost of new entry, under current market rules, the demand curve will shift as a consequence of the change in ICAP Reference Price.

As discussed above, the cost of new entry could be affected by a reduction in financial risk or a change in post-entry operating costs (e.g., commitment risks).[60] The following sections evaluate potential changes in the cost of new entry arising from the switch to a forward market and the introduction of a price lock-in. Figure 10 illustrates how a reduction in net CONE arising from, for example, a reduction in the cost of finance for a new resource, would translate into a change in the demand curve. Assuming a fixed supply curve, a forward market with a 7- year lock-in will lower both the market-clearing price and the quantity of capacity procured.

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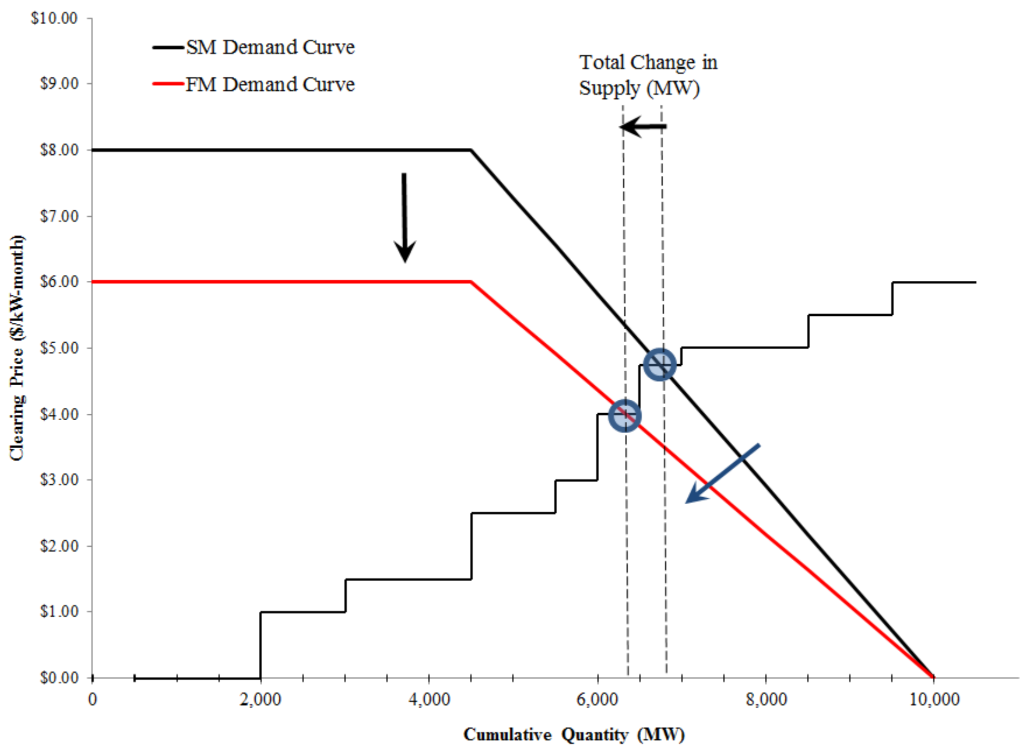
unit outages and load and transmission forecasts. For the purposes of this analysis, we have assumed that the IRM (and LCR) values would remain the same under both a forward market and a spot market. However, we recognize that changes in a forward market may both increase or decrease future IRM values relative to a spot market. For example, as discussed in Section IV, a forward market will tend to have greater load forecast uncertainty three years out than a spot market forecast set one year out. Load forecast error tends to increase IRM values. Similarly, as discussed in Section IV, a forward market may increase fleet turnover and accelerate retirements of older, less efficient generating units. The addition of new, more efficient generation will tend to lower the system average EFORd, which decreases IRM. It is difficult to predict the relative magnitude of these changes, but on net, they may be expected to offset one another such that IRM values are likely to remain the same under both market structures.

[59] Independent Study to Establish Parameters of the ICAP Demand Curve for the New York Independent System Operator. NERA Economic Consulting, Final Report, August 2, 2013, at pages 82-89.

[60] The cost of new entry will be affected by additional costs after year 7, when these new resources will face the same deficiency penalty and economic risks as existing resources.

Figure 10: Illustrative Shift in Forward Market Demand Curve, 7-year Lock-In when supply and demand curves intersect



In some capacity zones, the supply curve may not cross the demand curve (Figure 11). As discussed below, we observe this situation in the NYC and G-J zones for the year 2020. In these situations, the model clearing price is set at the crossing point of a vertical line drawn from the last unit in the supply curve with the demand curve.[61] In this instance, the change in clearing prices is driven exclusively by the change in the demand curve – even if the supply curve or the marginal unit bids a different cost in a spot and forward market. The total cleared quantity is the same in both a forward and spot market.

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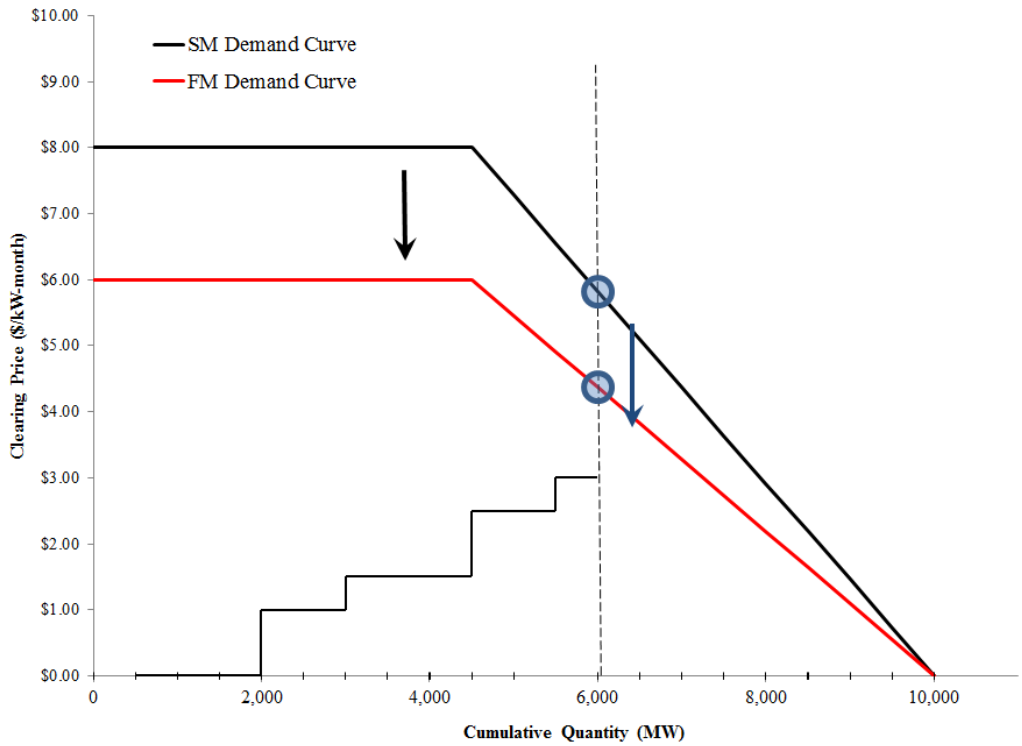
[61] This is consistent with the current market rules for mitigated zones. See NYISO Market Services Tariff, Attachment H Mitigation Measures, Section 23.4.5.2: "Offers to sell Mitigated UCAP in an ICAP Spot Market Auction shall not be higher than the higher of (a) the UCAP Offer Reference Level for the applicable ICAP Spot Market Auction, or (b) the Going-Forward Costs of the Installed Capacity Supplier supplying the Mitigated UCAP."

Figure 11: Illustrative Shift in Forward Market Demand Curve, 7-year Lock-In when supply and demand curves do not intersect



2. *Changes to the Demand Curve from a Forward Market (with No Lock-In Feature)*

The shift to a forward market structure has many potential financial consequences for new investment. On the one hand, a forward market may lower risk by coordinating entry among competitors (i.e., avoiding risk of excess entry), and allow forward (three year) ahead financial commitment. One the other hand, a forward market may increase risk through deficiency payment risk and commitment risk (i.e., reduced optionality). While a change to a forward market could affect the flow and uncertainty over future revenue streams, the precise impact in terms of financial risk is difficult to quantify. There are multiple factors that affect a project's financial risk, and quantifying the effect of any one of these factors is difficult, let alone the combined effect across all factors. Although we do not develop estimates of the impact of a forward market on the cost of finance, we suspect that any impact is unlikely to be large, particularly compared to the potential impact of an optional price lock-in, which we assess in the next section. Consequently, we do not quantitatively analyze differences in market outcomes associated with a change of cost of capital due solely to the shift from a spot to a forward market structure.

3. *Changes to the Demand Curve from a Forward Market with Price Lock-In*

The introduction of a price lock-in has (at least) two potential effects on the cost of new entry, both of which are estimated when developing ICAP demand curves. The first effect is that a price lock-in will fix revenue streams at a constant level over the first seven years. By contrast, in the current demand curve reset model revenues are greatest in the first year, but decline in the second and subsequent years. Thus, in principle, fixing revenues over the first seven years could affect the net CONE estimates. Based on our analysis, a price lock-in with reduced financing costs would likely have a relatively modest effect on the cost of new entry relative to a price lock-in without reduced financing costs, decreasing revenue needs by 2 to 12 percent across zones. Because these impacts are small in comparison to the effects from the change in finance costs, we do not explicitly consider this effect within our analysis. To the extent such an affect was meaningful, it would shift likely impacts toward the higher end of the range reported below, thus suggesting that our mid-point values are conservative.

The second impact of a price lock-in on net CONE occurs through the cost of finance. A key element in determining the cost of new entry is the cost of financing new plant investment. Financing costs depend on both the cost of debt, which reflects the interest rate demanded by debt holders, and the cost of equity, which reflects the expected return demanded by equity investors. Depending on the proportion of debt and equity used to finance new investment, the resulting after tax weighted average cost of capital (ATWACC) is a key input to the calculation of the net CONE.

In this section, we consider the potential impact on the cost of finance from a change to a forward market structure and providing new resources with the option of a multi-year price lock-in. In principle, by changing the flow and uncertainty of future revenue streams, both of these changes could have consequences for the cost of finance. Our assessment identifies the mechanism through which these changes may affect the cost of capital for new resources, and characterizes the potential magnitude of these effects through a combination of market information and evaluation of economic fundamentals.

This assessment necessarily faces many uncertainties. As noted by NERA, "the capital structure and costs of capital is an issue over which stakeholders hold multiple perspectives."[62] Moreover, assessments of the appropriate cost of capital for new generation resources often rely on different underlying assumptions.[63] Along with providing information relevant to understanding and

[62] NERA, "Independent Study to Establish Parameters of the ICAP Demand Curve for the New York Independent System Operator," Final Report, August 2, 2013, p. 83. Similarly, the Brattle Group notes that "there is significant uncertainty in any single cost of capital estimate…". Brattle Group, Cost of New Entry Estimates for Combustion Turbine and Combined Cycle Plants in PJM, With June 1, 2018 Online Date, Prepared for PJM, May 15, 2014, at page 35.

[63] For example, while NERA assumes a cost of capital for an investment grade company, Brattle relies on the cost of capital for current merchant generating companies, which are all current not investment grade (i.e., Calpine,

characterizing the magnitude of potential impacts, we develop estimates of the range of potential impacts to the finance costs that we use in our quantitative analysis.

Lock-in provisions provide developers of new resources with the option to lock-in clearing prices for a multi-year period. Under these lock-in provisions, a market participant offering new capacity would have the option to either (1) receive the first-year forward clearing price in the first year and market prices in subsequent years or (2) receive this first-year clearing price for a multi-year period.[64] Our assessment assumes a 7-year lock-in period within the forward market structure.

A price lock-in within a forward market can reduce the financial risk associated with a new resource's future revenues and costs, which can lower the cost of project financing, all else equal. A project's cost of capital reflects the many market, operating and business risks facing the project given market conditions, the technology used, siting risks and many other factors. Such costs generally do not reflect the developer's financial position or source of funds (e.g., internal balance sheet or external funds).[65] Consequently, when considering the potential benefits of a price lock-in for cost of finance, we focus attention largely on the project, rather than the developer, attributes.

A price-lock-in potentially lowers the cost of capital through several mechanisms. Within the firm, reduced revenue variability can allow companies to increase reliance on internal (usually less costly) finance for operations and new investment, avoid the costs associated with financial distress, and mitigate agency costs within the firm.[66] These benefits are the basis for risk management activities undertaken by most market participants. For external finance, reduced revenue variability from a lock-in may lower the cost of finance offered by investors, particularly when returns are tied to the particular new resource or project (e.g., as with project finance).

To evaluate the potential changes in financing costs associated with a price lock-in, we evaluate several sources of information. First, we evaluate the costs of debt associated with recent thermal power projects. Second, we evaluate the change in financial metrics used to assess credit risk due to the reduction in capacity price risk from a price lock-in. Third, we consider potential impacts

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Dynegy, and NRG). NERA, 2013; Brattle, 2014.

[64] With a price lock-in, an important design question is whether a new resource's option to lock-in prices must be made along with the resource's offer other offer terms of whether the option can be exercised after the auction when clearing prices have been revealed. To the extent that offering a lock-in is designed to lower financial risk, requiring that the lock-in be exercised along with the resource offer seems consistent with this objective. While allowing the option to be exercised after the auction certainly makes the option more valuable, this value is achieved by providing the entrant with an additional risky asset (along with the entry decision it is making). Moreover, to the extent that the resource is uncertain it would exercise the option at its entry price, this suggests that the lock-in is not a necessary condition to facilitating entry and, to the extent that the option lowers the resource offer, this lower offer is achieved through transfer of the risky financial asset (the lock-in option) and may come at the price of making the resource less financially viable should the market clear at its entry offer.

[65] "The company's cost of capital is *not* the correct discount rate if the new projects are more or less risky than the firm's existing business. Each project should in principle be evaluated at its *own* opportunity cost of capital." Brealy, Richard, Stewart Myers and Franklin Allen (2008), *Principles of Corporate Finance*, ninth edition, McGraw-Hill Irwin: New York, New York, pages 239 (emphasis in the original).

[66] For example, *see* Brealy, Myers and Allen (2008), pages 722-726.

to required returns on equity given the change in risk associated with a capacity price lock-in. Based on this information, we develop an estimated range of potential impacts to the debt and equity associated with new development.

In contrast, we do not assume a lock-in within the current spot market structure. In theory, it may be possible to include a lock-in with the current spot market construct. However, such a design may be difficult to implement for a number of practical reasons and may not achieve the intended effect of lowering new development financial risk. In a spot market – and unlike a forward market – developers of a new resource secure project financing *before* the resource clears in the capacity market. Given this, the price at which the lock-in may be set is uncertain at the time of development. Therefore, the lock-in would not provide additional revenue certainty, and thus would be unlikely to lead to a reduction in project finance costs.

a) Cost of Debt from Recent Projects

The financing terms for new merchant projects provide one source of information on the effect that a capacity price lock-in may have on financing costs for new resources. Our analysis of new power projects focuses on merchant projects developed within the U.S. These new projects are developed under a range of market and contract conditions that provide information on how these terms affect underlying finance costs. The interest rate associated with financing to support a particular project will depend not only on these market and contract conditions, but on many factors, including the underlying project economics (i.e., expected net revenues relative to costs), the ratio of debt to equity, the tenor (length) of the debt, terms limiting or supporting debt payback (e.g., non-recourse debt, case set-asides (cash sweeps)), fixed versus variable interest rates and debt amortization (i.e., extent of "balloon" payments at the end of the debt term).

An important factor in determining a project's cost of capital is the mechanisms project developers have in place to hedge financial risks from plant operations, including purchase power agreements (PPA), tolling agreements and financial (derivative) hedges. Fitch notes that: "Consistent with the Master Criteria, the revenue stream stability of a project is critical to its credit quality. The degree to which thermal power projects are exposed to revenue risk varies from contracted projects (largely insulated from market risk) to merchant projects (significantly exposed)."[67] In our analysis, we use variation in these financing terms across contracts to identify the change in financial terms associated with a 7-year price lock-in.

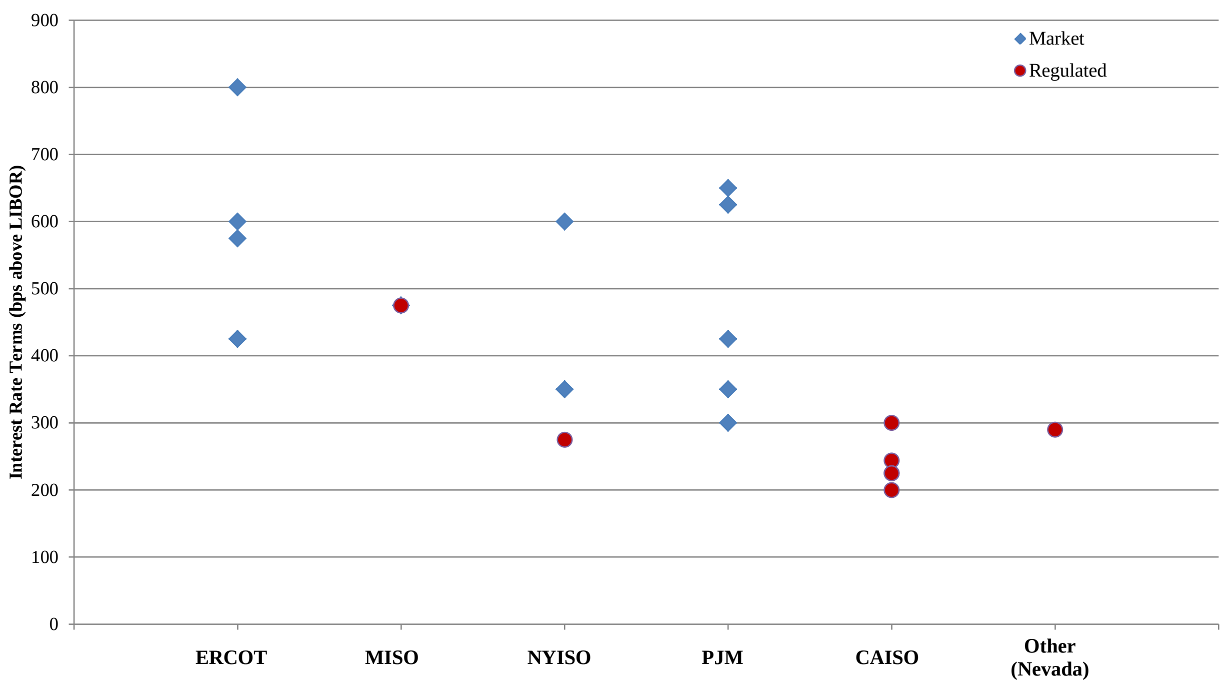
Figure 12 illustrates the debt costs (rates) associated with debt issues for merchant projects built between 2010 and 2014, while Appendix II provides further detail on these projects. Our sample includes 19 projects across multiple regions and developers. The circumstances and terms of

[67] Fitch Ratings, "Rating Criteria for Thermal Power Projects," Global Infrastructure & Project Finance, July 30, 2014.

deals in our sample vary and often are not fully known. These terms include, for example, project economics, debt to equity ratio, tenor, cash sweep and amortization. Figure 12 organizes these projects by market, with the markets sequenced (from left to right) in terms of the amount of financial support provided for capacity payments, including the operation of an organized capacity market and the ability to enter into long-term contracts. From left to right: ERCOT has no capacity market; MISO has a voluntary capacity market; NYISO has a spot capacity market; PJM has a forward capacity market; and California and Nevada have 10-year PPAs.

As shown in Figure 12, the cost of debt issues are roughly declining from left to right with more organized capacity markets and reduced uncertainty in capacity market revenues. While most financings considered reflect new projects, two of the three deals in NYISO involve the refinancing of existing projects and the third deal reflects a long-term PSC-approved contract. Thus, while the figure illustrates relatively little apparent difference between financing terms in NYISO and PJM, given that the NYISO deals reflect refinancing and not new issues, caution should be used in drawing inferences from these comparisons. Appendix II provides other information about these recent merchant power projects.

Figure 12: Interest Rates for New Resource Debt Issues, by Region, 2010 to 2014



Notes:

[1] NYISO projects include Linden Cogeneration (948 MW CC), Bayonne Energy Center (512 MW CT), and a 2012 Astoria Generating Co. refinancing.

Sources:

[1] Project Finance International.
[2] Company specific 10-K financials.
[3] SNL Financial.

Several points emerge from this survey. First, all of the projects represented in Table A.II reflect circumstances in which projects are being developed through financing involving limited or no recourse debt. While not all projects are developed through this approach, information on non-recourse debt provides information on project-specific risks that are of interest for our analysis. Moreover, our sample is likely representative of the range of projects being developed given the variation in construction, operating and market risks. Second, the entities on this list include both investment grade and non- investment grade companies. Non-investment grade entities include Calpine, NRG and debt issues for Bayonne (ArcLight and Hess) and Empire Generating Company (refinancing), while investment grade entities include Exelon, Marubeni Corporation and General Electric Capital. We do not take a position on whether resources developed within the NYISO market would be developed by an investment or non- investment grade company. Our analysis of recent projects developed suggests that companies with varying credit-quality have been developing resources in a range of markets. We see nothing unique about current market and financial conditions to suggest that this trend will change in the future. Moreover, the fact that companies of varying credit quality pursue stand-alone debt illustrates that underlying project risks – not the credit quality of project developers – drives the cost of debt faced by new resource developments.

To estimate the impact of a 7-year price lock-in on debt finance costs, we compare financing terms from the actual projects reported in Figure 12 and Table A.II. Specifically, our estimate is based on several comparisons of debt costs for projects developed in the PJM and CAISO markets. Projects developed in these markets provide the best comparison of rates among the sample of projects available to us.[68] Table 3 provides comparisons of debt costs between PJM and CAISO. First, we compare the debt costs for two companies – Calpine and Competitive Power Ventures (CPV) – that have each developed a project in the two markets. For Calpine, debt cost is 75 bps higher in PJM, while for CPV, the debt cost is 162.5 bps higher in PJM. Second, we estimate the average and median debt costs across projects in each market. On average, debt costs are 236.2 bps higher in PJM and the median project is 200 bps higher in PJM.

[68] ERCOT projects reflect terms for projects with no capacity market, while NYISO projects reported include debt refinancing of two existing projects and a new project financing with somewhat unique circumstances (Bayonne Energy Center).

Table 3: Change in Cost of Debt (basis points above LIBOR)

	CAISO	PJM	Difference	Adjusted for [2] 10 year cashflow	Adjusted for [3] 20 year cashflow
By Developer					
Calpine	225	300	75	57.5	53.2
CPV	225	387.5	162.5	124.7	115.3
By ISO					
Average (by ISO)	238.8	470.0	231.2	177.4	164.0
Median (by ISO)	225	425	200	153.5	141.9

Notes:

[1] Rates are reported as basis points above LIBOR, based on stated financing terms for individual projects in each region by developer.

[2] Values are adjusted to account for the difference in net present value cash flows earned in years 1 - 7 compared to years 1 - 10 years, assuming an even flow of capacity revenues in each year.

[3] Values are adjusted to account for the difference in net present value cash flows earned in years 1 - 7 compared to years 1 - 20 years, assuming capacity revenues for a PPA in years 1-10 and the CPUC RAR in years 11-20.

Sources:

[1] Project Finance International.

[2] Company specific 10-K financials.

[3] SNL Financial.

Because the CAISO PPAs extend for 10 years, these contracts provide greater reduction in financial risk than the 7-year lock-in contemplated for NYISO. In some instances, these PPAs also include provisions for the sale of energy and capacity. For the purpose of this analysis, we did not account for impacts of expected energy market revenues on project finance metrics. In NYISO, new CT or CC resources would expect to be dispatched when economic and earn energy revenues that are likely proportional to expected energy generation under a more traditional utility scheduled dispatch model. In this sense, a NYISO project already includes a similar level of certainty with respect to energy market revenues.

To develop an estimate of the change in debt costs associated with a 7-year capacity price lock-in, we rely on the difference in debt costs between PJM and CAISO markets to capture the value of price lock-in for a 10-year period. Using this difference, we use two approaches to estimate the reduction in financial cost from a 7-year price lock-in that can be applied to the levelized cost of debt over the full project term. Each approach relies on interpolating between the debt costs for the PJM market, with no lock-in period, and the CAISO market, with a 10 year lock-in.[69] The first approach

[69] PJM allows a 3 year price lock-in for eligible resources. Through 2011, eligibility criteria appear to be so restrictive that almost no resources have been granted a lock-in, despite interest. A Brattle Group study found that of 30 companies that requested a lock-in, only one qualified. Brattle Group, "Second Performance Assessment of PJM's Reliability Pricing Model," August 26, 2011, page 153. More recently, the NEPA has only been exercised for a single unit in DPL South for the 2014/2015 BRA. Monitoring Analytics. "Analysis of the 2014/2015 RPM

relies on the difference in the duration of the NYISO lock-in under consideration and the CAISO PPA terms, assuming constant stream of annual capacity market revenues and a ten-year debt term. Debt costs are adjusted by the ratio of (1) expected discounted capacity market revenues over 7 years to (2) expected discounted capacity market revenues over 10 years. The second approach relies on the same approach, except we assume a 20-year debt term.[70] As a result, in the second approach, debt costs are adjusted by the ratio of (1) expected discounted capacity market revenues over 7 years to (2) expected discounted capacity market revenues over 20 years. These adjusted values provide an approximation of the levelized cost of debt reduction over the 20 year project term from a 7 year lock-in.

Table 3 reports the adjusted values developed using these two approaches. These adjusted values correspond to estimates of the change in debt costs associated with a 7-year capacity price lock-in. Comparisons are made between two companies that have developed projects in both markets (Calpine and Competitive Power Ventures, or CPV) and across all projects developed in the two markets. First, we note that the two approaches produce relatively consistent adjusted debt cost estimates. This is a consequence of the fact that, with time discounting, much of the present value of a project's capacity revenue stream is accounted for in the first seven years of the asset life. Second, the variation in metrics for the impact of a 7-year lock-in ranges from 53.2 to 164 basis points (bps), with the differences between individual developers lower than those across the entire sample.

b) *Pro Forma Evaluation of Debt Costs*

Another approach to evaluating the impact of a 7-year lock-in on the cost of debt is through analysis of how the lock-in would affect a project's finances. Project finances are analyzed through a prospective or *pro forma* financial statement, which evaluates the project's underlying economics given capital needs and potential future revenues and costs.[71] Financial metrics based these pro forma financial statements are commonly used by credit rating agencies such as Fitch, Moody's and Standard & Poor's as an important piece of information used when evaluating the credit-worthiness (and assigning credit ratings) to a company or particular bond issue. One important metric is the Debt Service Cover Ratio (DSCR), which measures the ratio of available cash flow to the amount of debt that needs to be repaid.

When this ratio is higher, debt holders have greater assurance that debt holders will have sufficient cash to repay debts, particularly given uncertain events that can lead actual cash flows to

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Base Residual Auction", April 9, 2012, page 43.

[70] Our analysis also accounts for changes in capacity revenues over time in CAISO, with be higher revenues during the 10 year PPA in comparison to the subsequent 10 years. We assume that generators receive the weighted average resource adequacy price of $3.28/kW-mo in years 11-20 (Staff of the California Public Utilities Commission, *2012 Resource Adequacy Report*, April 2014, pages 21-29) and long-term procurement plan price of $205/kW-mo in years 1-10 (The Brattle Group, "Resource Adequacy in California, Options for Improving Efficiency and Effectiveness," prepared for Calpine, October 2012, pages 12-14.).

[71] When evaluating cost of finance for new resources, the appropriate financial entity may be either the corporation as a whole or the project by itself.

differ from expected cash flows. Consequently, a debt issue with a higher DSCR will have a better credit rating and lower interest rate, all else equal.

Tables 4 and 5 provide a pro forma assessment of the cash flow, debt service cost and DSCR for combustion turbine and combined cycle units in each zone – NYCA, NYC, Long Island and Zones G-J. The revenues, operating costs and financial costs in Table 4 are based on the reference price model used in developing the NYISO Spot Market demand curves.[72] Net cash flow reflects the amount of cash available from operations to pay debt service and provide a return to equity, and is based on the net energy and ancillary services revenues, capacity market revenues and operating costs (insurance, operations and maintenance, and property and income taxes). The DSCR is calculated as the ratio of the net cash flow to the debt service.

Table 4: Combustion Turbine, Change in Debt-Service Coverage Ratio with 7 year Lock-in Assuming 35 percent reduction in E/AS revenues

7-year Lock-in	**Notes**	**NYCA**	**NYC**	**Long Island**	**G-J Locality**
[a] Energy Margin		$1.00	$1.81	$4.68	$1.77
[b] Capacity Payments		$6.92	$12.06	$4.89	$8.36
[c] Insurance + O&M		$1.07	$2.71	$1.71	$1.57
[d] Property and Income Taxes		$1.27	$1.65	$1.80	$1.65
[e] Net Cash Flow	= [a]+[b]-[c]-[d]	$5.57	$9.51	$6.05	$6.91
[f] Debt Service		$2.37	$3.80	$3.36	$3.07
[g] Debt Service Coverage Ratio	= [e]/[f]	**2.35**	**2.50**	**1.80**	**2.25**
Stress Test Scenarios					
Decline in Capacity Prices	-25%				
[h] Weighted Average Prices		$5.19	$9.05	$3.66	$6.27
[i] Implied Annual Net Cash Flow	= [a]+[h]-[c]-[d]	$3.84	$6.50	$4.83	$4.82
[j] Implied Annual 2013 DSCR	= [i]/[f]	**1.62**	**1.71**	**1.44**	**1.57**
[k] Difference from Year 7 DSCR	= [g]-[j]	**0.73**	**0.79**	**0.36**	**0.68**
5-year Historical Average Price					
[l] Weighted Average Prices		$2.34	$9.60	$2.69	-
[m] Implied Annual Net Cash Flow	= [a]+[l]-[c]-[d]	$0.99	$7.05	$3.85	-
[n] Implied Annual DSCR	= [m]/[f]	**0.42**	**1.86**	**1.15**	-
[o] Difference from Year 7 DSCR	= [g]-[o]	**1.93**	**0.65**	**0.65**	-

[72] Independent Study to Establish Parameters of the ICAP Demand Curve for the New York Independent System Operator. NERA Economic Consulting, Final Report, August 2, 2013.

Table 5: Combined Cycle, Change in Debt-Service Coverage Ratio with 7 year Lock-in Assuming 35 percent reduction in E/AS revenues

7-year Lock-in	Notes	NYCA	NYC	Long Island	G-J Locality
[a] Energy Margin		$3.63	$5.44	$10.28	$5.47
[b] Capacity Payments		$10.56	$17.00	$4.94	$10.27
[c] Insurance + O&M		$2.55	$4.53	$3.48	$3.17
[d] Property and Income Taxes		$2.53	$2.96	$3.24	$2.90
[e] Net Cash Flow	= [a]+[b]-[c]-[d]	$9.12	$14.95	$8.50	$9.66
[f] Debt Service		$4.10	$5.90	$5.26	$4.70
[g] Debt Service Coverage Ratio	= [e]/[f]	**2.23**	**2.53**	**1.62**	**2.06**
Stress Test Scenarios					
Decline in Capacity Prices	-25%				
[h] Weighted Average Prices		$7.92	$12.75	$3.70	$7.70
[i] Implied Annual Net Cash Flow	= [a]+[h]-[c]-[d]	$6.48	$10.70	$7.26	$7.10
[j] Implied Annual 2013 DSCR	= [i]/[f]	**1.58**	**1.81**	**1.38**	**1.51**
[k] Difference from Year 7 DSCR	= [g]-[j]	**0.64**	**0.72**	**0.23**	**0.55**
5-year Historical Average Price					
[l] Weighted Average Prices		$2.33	$9.56	$2.68	-
[m] Implied Annual Net Cash Flow	= [a]+[l]-[c]-[d]	$0.89	$7.51	$6.23	-
[n] Implied Annual DSCR	= [m]/[f]	**0.22**	**1.27**	**1.19**	-
[o] Difference from Year 7 DSCR	= [g]-[o]	**2.01**	**1.26**	**0.43**	-

Notes and Sources (Table 4 and 5):

[1] Debt Service Coverage Ratios, including estimated energy margins [a] and capacity payments [b] and unit specific costs[c] and [d], were developed using the demand curve reference models used in the 2014-2017 demand curve reset study. Estimates assuming a 7-year Lock-in are based on modeled revenues for the reference unit, assuming payments in year 7.

[2] Stress test scenarios were developed using historical NYISO ICAP Spot market clearing prices and assume a 35 percent reduction in energy and ancillary service revenues.

[3] All values are converted to $/kW-month using ICAP for the applicable reference unit.

Sources:

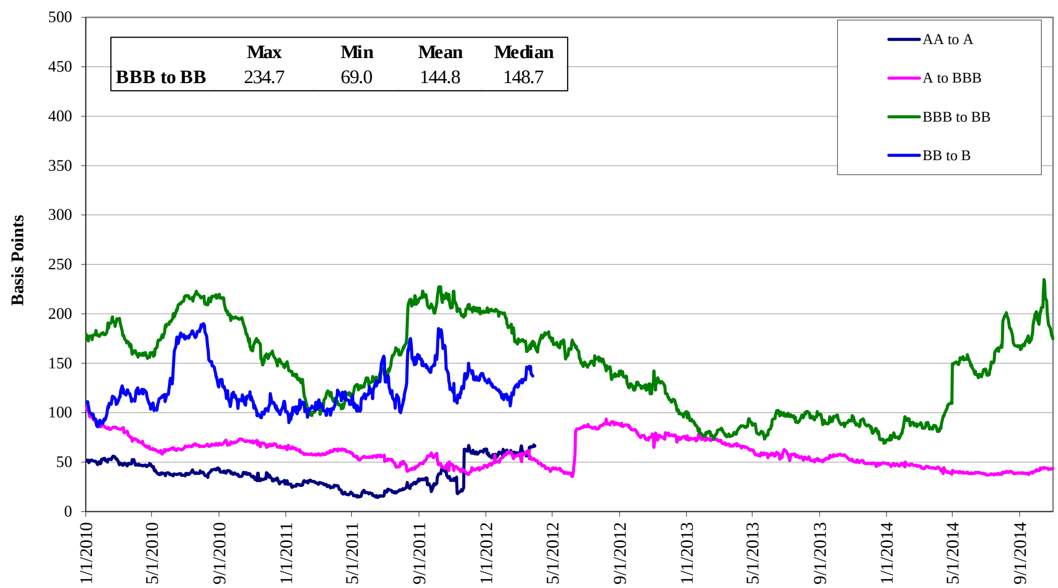
[1] Demand Curve Reference Models, posted October 30, 2013.

[2] Historical NYISO ICAP spot market clearing prices, available: http://www.nyiso.com/public/markets_operations/market_data/icap/index.jsp

When assessing the credit-worthiness of a project or entity, credit agencies typically evaluate financial metrics under a number of different scenarios including expected market conditions and downside or stress conditions.[73] Downside or stress conditions are evaluated to determine the likelihood that debt holders will receive payment under difficult financial circumstances, such as persistent operational problems, major outages, and depressed power prices

Tables 4 and 5 consider downside case assumptions for energy and capacity markets. For energy and ancillary service net revenues, we assume a 35 percent reduction from expected levels.[74] For capacity markets, we assume that the 7-year lock-in fixes capacity prices at levels consistent with the cost of new entry. Without a price lock-in, we assume that capacity prices are either (1) 25 percent below the amount needed to fully recover costs, or (2) the average capacity price in the NYISO market over the prior five years. This lower level of revenues based on past capacity market conditions is reasonable in the context of approaches taken by credit agencies to defining such downside cases.[75]

Figure 13: Change in Credit Spreads, Fair Value Effective 5 Year Bond Yields



Source:
[1] Bloomberg, accessed November 3, 2014

[73] Fitch evaluates thermal power projects under a "combined downside" case reflecting a "combination of operational and economic stresses that simulates a scenario of material underperformance" and under "Individual Stresses", reflecting a "project's ability to withstand severe one-off stresses (such as extended major outages or temporarily depressed power prices)". FitchRatings, Global Infrastructure & Project Finance, "Rating Criteria for Thermal Power Projects," July 30, 2104. Similarly, S&P considers a "downside case".

[74] Results with no reduction in expected energy and ancillary service revenues have higher DCSRs, but the change in the DCSR with and without the 7-year lock-in is the same as those reported in Table 4 and Table 5.

[75] For example, S&P's downside case assumes "the most unfavorable power price expected over the next 20 years" and "one-third of the capital cost required to attract investment in new power plants". Standard & Poor's, "Project Finance: Key Credit Factors for Power Project Financings," September 16, 2014.

For combustion turbines, the DSCR ranges from 1.80 to 2.50 across zones with the 7-year lock-in (row [g]). With a lock-in, the DSCR range from 1.44 to 1.71 assuming a 25 percent reduction in capacity revenues (row [j]) and 0.42 to 1.86 using the five year historical average (row [n]).[76] The resulting change in DCSR value ranges from 0.36 to 0.79 with the 25 percent reduction in capacity price, and 0.65 to 1.93 with the historical average. For the combined cycle facility, the results are similar. The range of DSCR values is 1.62 to 2.53 with the 7-year lock-in. With the lock-in, DSCR values range from 1.38 to 1.81 with the 25 percent reduction in price, and 0.22 to 1.27 with the five-year historical average. The resulting change in DSCR value ranges from 0.23 to 2.01.

The implications of these changes in DCSR values for debt costs depend on various operational and market risks facing the project. Guidance from credit rating agencies provides DSCR value ranges that correspond to particular credit ratings given project riskiness. For example, Standard & Poor's provides guidance that the DCSR values to support a given credit rating. For a given level of business conditions and project riskiness, the range in DCSR values that would support a BBB rating varies from 0.1 to 0.75.[77] Based on this guidance, these changes in DSCR value are large enough to suggest that a 7-year lock-in could lead to a credit rating reduction of at least one level (e.g., from a rating of A to BBB, or from a rating of BBB to BB), and possibly more. Historically, the additional cost of debt associated with a one notch difference in credit rating has varied over time. Figure 13 illustrates the difference in credit spreads between 5-year bond issues with different credit ratings from 2010 to present.[78] The basis differential between A to BBB rated bonds has ranged from 40 to 90 bps, while the drop from investment grade (BBB) to non-investment-grade (BB) has range from about 80 bps to about 225 bps.

c) Cost of Equity

A capacity price lock-in also has implications for the returns demanded by the project equity holders. Consistent with the basic Capital Assets Pricing Model (CAPM) framework, the appropriate return on equity for a merchant generation project reflects the correlation in returns to equity holders (as reflected in net revenue streams) with the broader economy. These "systematic" risks cannot be diversified away in the same manner as idiosyncratic risks that can be reduced through the "pooling" of returns from many different assets. Under this framework, the required return on equity reflects the risk-free rate of return and this correlation – also referred to as the project's "beta" – and the expected

[76] In some cases, our analysis suggests that new resource development is uneconomic given historical prices. For example, based on historical prices, the DSCR value would suggest that a new CT resource would be uneconomic in NYCA. This finding is supported, in part, by the fact that no new CT units have entered the NYCA market over this period.

[77] For example, the DCSR values that support a BBB rating at moderate business risk range from 1.4 to 2.0, and thus has a range of 0.6 – that is, 2.0 minus 1.4. Standard & Poor's, "Project Finance: Project Finance Operations Methodology," September 16, 2014; FitchRatings, "Rating Criteria for Thermal Power Plants," Global Infrastructure & Project Finance, July 30, 2014.

[78] These values are consistent with basis differential from pre-recession periods. Note that the credit spreads for longer issues (e.g., 20-years) issues are similar to those for 5-year issues.

economy-wide risk premium (EERP).

It is reasonable to assume that the returns to merchant power plants are positively correlated with the overall economy. When the economy is doing well, increased demand will push prices and demand for merchant power plant output, including energy, ancillary services and capacity. This intuition is borne out by the actual betas of companies in the electric power sector. One recent study reported betas for a range of companies in the power sector: merchant power company beta's ranged from 1.10 to 1.20; fully regulated, vertically-integrated utility betas ranged from 0.55 to 0.70; and betas for companies combining regulated and merchant affiliates range from 0.65 to 0.85.[79]

Table 6 shows the betas for three merchant power companies – Calpine, Dynegy and NRG – as un-levered and re-levered betas (to account for company specific differences in debt to equity ratios), illustrating that there is variation in the betas for merchant power companies given factors related to operating and market performance and risks.

To identify estimates of the change in the return on equity arising from a 7-year lock-in to use in our quantitative analysis, we consider the variation in return on equity among merchant generation companies to be the most indicative of the change in risk from a 7-year lock-in. Specifically, for our quantitative modeling, we assume, guided by information in Table 6, that the 7-year lock-in will result in a 0.2 reduction in beta, and consider low and high scenarios in which beta is reduced by 0.1 and increased by 0.1, respectively. Using a 6.96 percent risk premium and a risk free rate of 5.09 percent, the re-levered betas in Table 6 correspond to calculated return on equity values of 9.8 percent, 12.6 percent, and 11.0 percent, respectively. To estimate the corresponding change in return on equity, we use the following formula, implied by the CAPM model:

$$\Delta \boldsymbol{ROE} = \Delta \boldsymbol{\beta} * \boldsymbol{EERP}$$

For *EERP*, we assume a value of 6.96 percent.[80] The resulting change in ROE ranges from 69 to 209 bps, with a mid-value of 139 bps. This approach is reasonable in light of differences in betas between different categories of companies in the electric power sector.[81]

[79] These estimates reflect levered betas. Independent Study to Establish Parameters of the ICAP Demand Curve for the New York Independent System Operator. NERA Economic Consulting, Final Report, August 2, 2013, at pages 82-89.

[80] Ibbotson, 2014 Ibbotson Stocks, Bonds, Bills, and Inflation Classic Yearbook, Morningstar: Chicago, Illinois, 2014.

[81] An alternative approach to estimating the ROE impact of a 7-year lock-in is to combine information about (1) the difference in ROE's between vertically integrated and merchant electricity companies and (2) information about the proportion of total revenue guaranteed by a 7-year capacity market price lock-in. We have not undertaken a comprehensive and thorough analysis of ROEs, which at minimum would be required to rely on this approach, but note that our results are bounded by estimates developed using such an approach from two sources. Based on the NYISO Demand Curve model, Combined Cycle units recover on average 25 percent of their total market revenues in the first seven years of operation, while Combustion Turbine units recover 36 percent over this period. Several data points inform the potential difference between regulated and merchant ROEs. First, based on companies identified in the NERA study, the average ROE for merchant generators is 11.29 percent, while the average ROE for

Table 6: Return on Equity, Beta Values for Select Merchant Companies

Company	5-yr Daily Beta as of 11/25/14	Re-Levered Beta Assuming 1:1 Debt-To-Equity Ratio
Calpine	0.85	0.68
NRG Energy	0.97	1.09
Dynegy	0.69	0.86

Source:

[1] Bloomberg, Accessed November 5, 2014.

d) Cost of Finance Estimates used in Quantitative Analysis

Our quantitative analysis considers the impacts of a 7-year lock-in on the WACC, and, as discussed earlier, also considers potential changes as a consequence of the switch to a forward market. Based on the market information and pro forma analyses provided above, we evaluate changes in cost of debt ranging from 50 bps to 200 bps, with 125 bps as an intermediate (reference) value. For return on equity, we assume that changes range from 69 to 209 bps, with mid value of 139 bps. These values reflect levelized values to be applied over a 20-year project duration. These values are intended to be representative of the range of potential impacts, recognizing that (1) the actual magnitude of such impacts will depend on particular circumstances, including project economics, finance terms and other contractual (hedging) arrangements available and (2) there are a number of challenges in attempting to quantify these impacts, given limitations in the data. Table 7 illustrates the impact of these assumptions for the after-tax weighted average cost of capital and current 2014 reference prices ($/ICAP), developed using the NERA demand curve model. Table 7 shows the reference price for the SM (which is the same as a FM without a lock-in) and FM with a lock-in, bounded by our range of financing impacts.

vertically-integrated utilities is 7.72 percent, a difference of 357 bps. Independent Study to Establish Parameters of the ICAP Demand Curve for the New York Independent System Operator. NERA Economic Consulting, Final Report, August 2, 2013. Second, a study by EPA found a merchant ROE of 16.1 percent and a utility ROE of 8.8 percent. (See Chapter 8: Financial Assumptions, Available here: http://www.epa.gov/powersectormodeling/BaseCasev513.html). These results suggest ROE impacts ranging from 88 to 370 bps after accounting for the relative proportion of capacity revenues earned in years 1 to 7 and 8 to 20.

Table 7: Cost of Financing Impacts to Reference Prices (2014 $/kW-month ICAP) Accounting for a 7-Year Lock-In

		Reference Point by Zone (2014 $/kW-month)			
Change to Cost of Financing	**After Tax WACC**	**NYCA**	**G-J Locality**	**Long Island**	**New York City**
Reference Price	6.37%	$8.84	$12.14	$7.96	$18.57
Low	5.89%	$8.41	$11.51	$7.19	$17.75
Base	5.32%	$7.94	$10.82	$6.35	$16.85
High	4.76%	$7.48	$10.14	$5.52	$15.97

Notes:
[1] Reference price unit is a combustion turbine peaking unit (SGT 6-PAC5000F(5) SC) with SCR in G-J, New York City and Long Island and without SCR in NYCA.
[2] Cost of Financing is modeled as a 125 bps reduction (+/- 75 bps) in cost of debt and 139 bps reduction (+/- 70) in cost of equity for base, low, and high respectively.

E. Results

The change in market outcomes for prices and quantities varies significantly across regions within the State. Regional differences in turn are a function of the unique characteristics of generators in each zone, the reliability requirements in each zone, and the total demand in each zone. In particular, there are important differences between market outcomes in mitigated zones (G-J, NYC) and non- mitigated zones (NYCA, LI) due the way the market clears when supply is below the demand curve.

As illustrated in Figure 14 through Figure 17, in mitigated zones, the difference between a forward and spot market is driven exclusively by the change in the demand curve. Here, the difference in the reference price with and without a lock-in as described in Table 7 is highlighted by a shaded blue box. In these regions, the market clears at a vertical line from the last bidding unit up to the demand curve. Therefore, the only difference in these zones is the height of the demand curve, which is determined by the reference unit.

In the non-mitigated zones, the impact of a forward market depends on both changes in the supply and demand curves. In this case, the slope of the supply curve also affects the magnitude of the price impact. When the supply curve is particularly steep, a change in load forecast will lead to a larger price impact. A comparison between NYCA and Long Island illustrates this point. In Long Island, the supply curve is relatively flat, which leads to a smaller price impact in comparison to the supply curve in NYCA. This result is explained in greater detail in Appendix III.

Figure 14: NYCA Forward and Spot Market, 2020

No New Entry Scenario

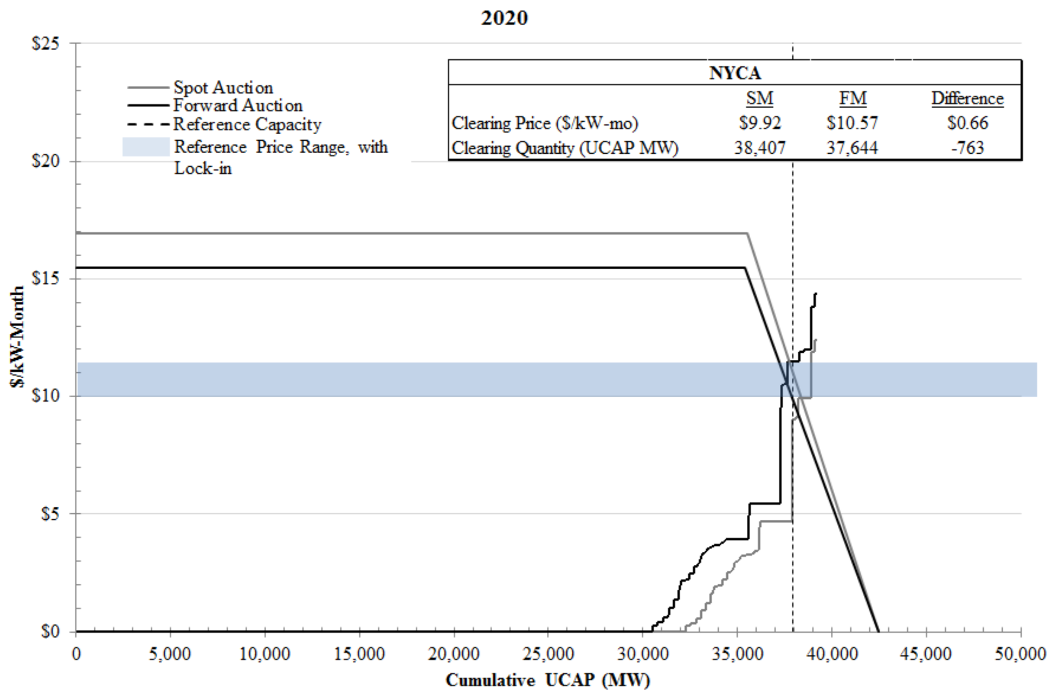


Figure 15: Long Island Forward and Spot Market, 2020
No New Entry Scenario

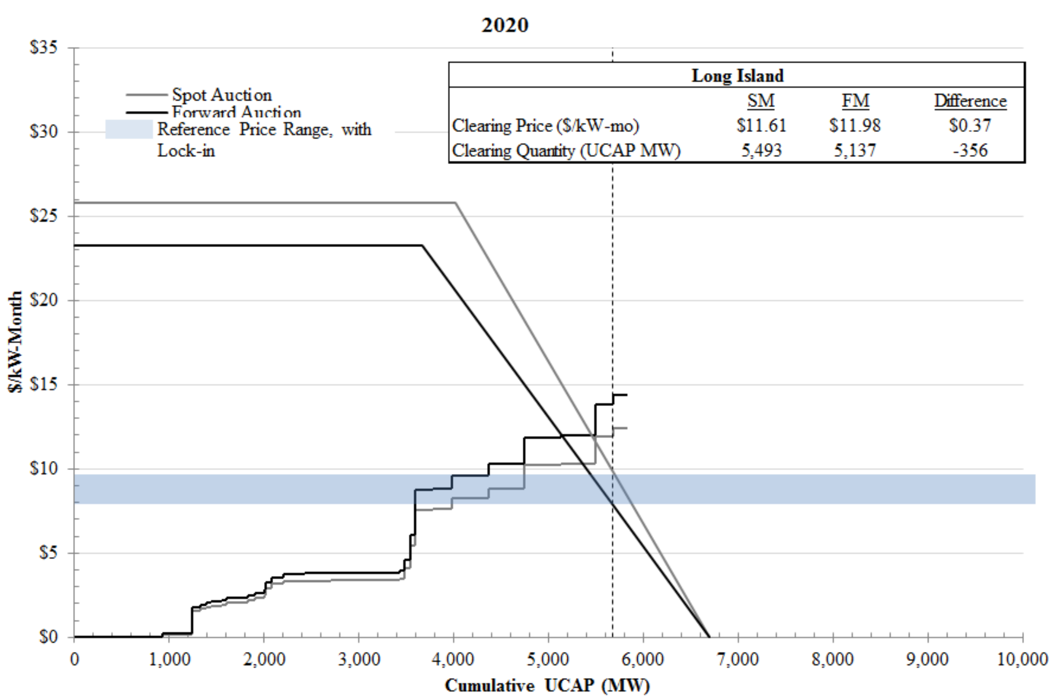


Figure 16: NYC Forward and Spot Market, 2020
No New Entry Scenario

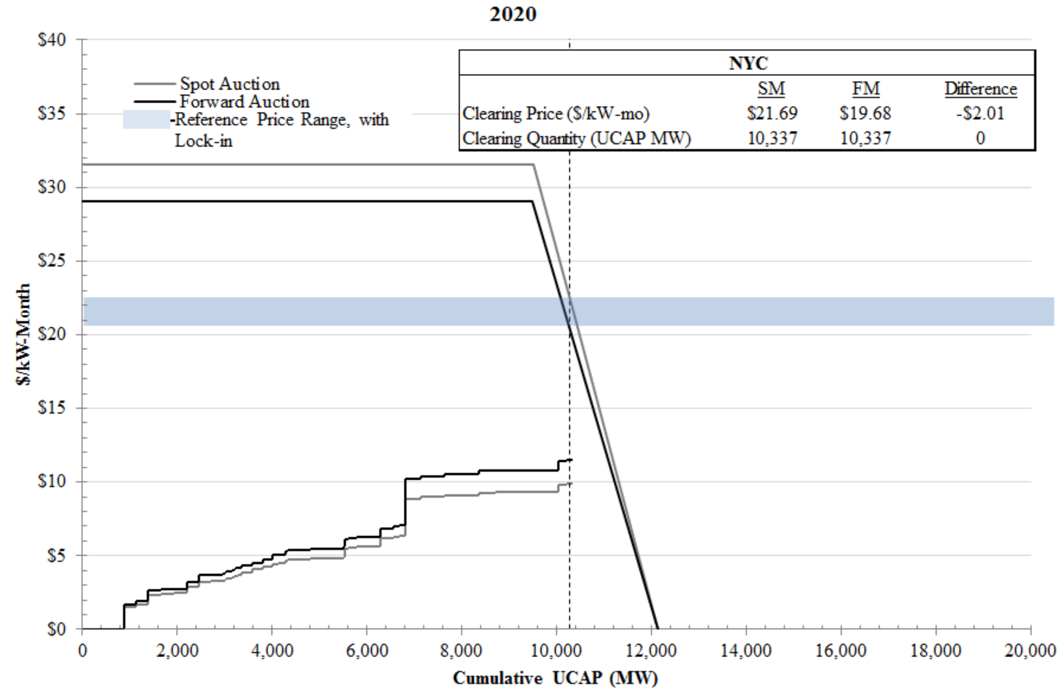


Figure 17: G-J Forward and Spot Market, 2020
No New Entry Scenario

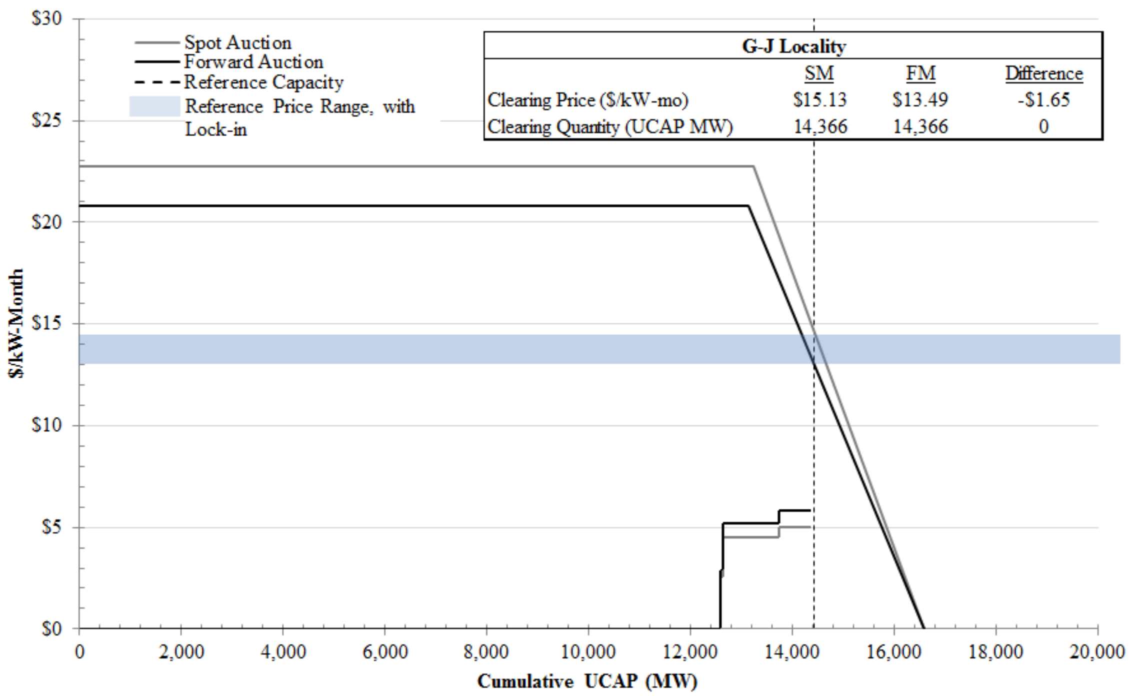


Figure 18 illustrates the change (calculated as FCM – Spot Market) in clearing prices and Figure 19 illustrates the change in clearing quantities for each scenario and each zone. In NYC and G-J, the change in clearing price is driven exclusively by estimated changes to the demand curve, captured through changes to net CONE. Without a lock-in, there is no change in clearing quantities *despite* an underlying change in the expected costs for new and existing generators because the clearing price is defined as the vertical crossing point with the demand curve. Absent a lock-in, there is no change in the demand curves between a spot and forward market. Within mitigated zones, this result is driven by the UCAP Offer Reference Level.[82] Absent new entry, a forward market in NYC and G-J will procure the same quantity of capacity as a spot market.

In Long Island and the rest-of-state, clearing prices increase in the forward market relative to a spot market due to the combined effect shifts in the supply and the demand curves. This increases the clearing price but also decreases the total quantity of cleared capacity. For example, in the New Entry at net CONE scenario, 2,169 MW of new entry would enter the LI zone at net CONE assuming a reduction in financing costs due to the 7-year lock-in. Without a lock-in, 1,316 MW of new entry would be expected to enter. This illustrates one scenario in which a forward market with a lock-in could procure a greater quantity of new capacity relative to a forward market without a lock-in.

Similarly, the total quantity of new entry in the forward market under the all coal retirement scenarios depends on the assumptions regarding new entry offer prices. Here, the analysis assumes that new entry offer prices in NYCA are equal to the net CONE. With a lock-in, the net CONE is reduced from $11.08/kW-mo ($2020 UCAP) to $9.95/kW-mo. At the lower entry price, a greater quantity of new entry clears the forward market (948 MW at the mid-point cost of financing impact compared to 631 MW without a lock-in and associated cost of financing impact). In these scenarios, no new entry is assumed in the spot market. In the coal retirements scenario, this results in greater price separation between the forward and spot markets, since the existing resources that set the price in the spot market are higher up the offer curve. Under the all coal retirements RSSA scenario, the resources with RSSAs are assumed to bid into the market as price takers, which reduces spot market clearing prices relative to the other coal retirement scenario, and the costs of RSSA payments are included in the total cost to load (as out of market payments).

Figure 20 summarizes new entry by scenario and highlights the finding that a forward market with a lock-in (shown here as the triangle with error bars) procures a greater quantity of new capacity in all scenarios and all zones, relative to both a forward market without a lock-in and a spot market. In all scenarios, new entry is assumed to bid at net CONE (in the forward market) and the potential supply of new resources is not limited, except to the extent that additional capacity clears above the demand curve. In all scenarios, the total quantity of cleared capacity is equal to the intersection of the supply and

[82] See NYISO Market Services Tariff, Attachment H Mitigation Measures, Section 23.4.5.2: "Offers to sell Mitigated UCAP in an ICAP Spot Market Auction shall not be higher than the higher of (a) the UCAP Offer Reference Level for the applicable ICAP Spot Market Auction, or (b) the Going-Forward Costs of the Installed Capacity Supplier supplying the Mitigated UCAP."

demand curves. In some cases, new entry displaces existing resources which do not clear the market. Therefore, the incremental impact of the new entry on the total procured quantity is less than the total quantity of new entry.

In the spot market, new entry occurs such that clearing prices including new resources are at or above net CONE. In scenarios with new entry (new entry at net CONE and both coal retirement scenarios), an important finding is that the quantity of new entry differs with and without a 7-year lock-in. In these scenarios, new entry bids at the assumed reference level (net CONE) for each zone. As discussed in section III.D and illustrated in Table 7, a 7-year lock-in is expected to lower the net CONE. At lower prices, greater quantities of new entry would clear a forward market. This finding is true both relative to a forward market without a lock-in and relative to the findings for new entry in the spot market. This finding is most noticeable in both Long Island and Western New York, in the coal retirement scenarios and new entry scenario.

Figure 18: Change in Clearing Price ($/kW-mo UCAP) By Zone ($2020)

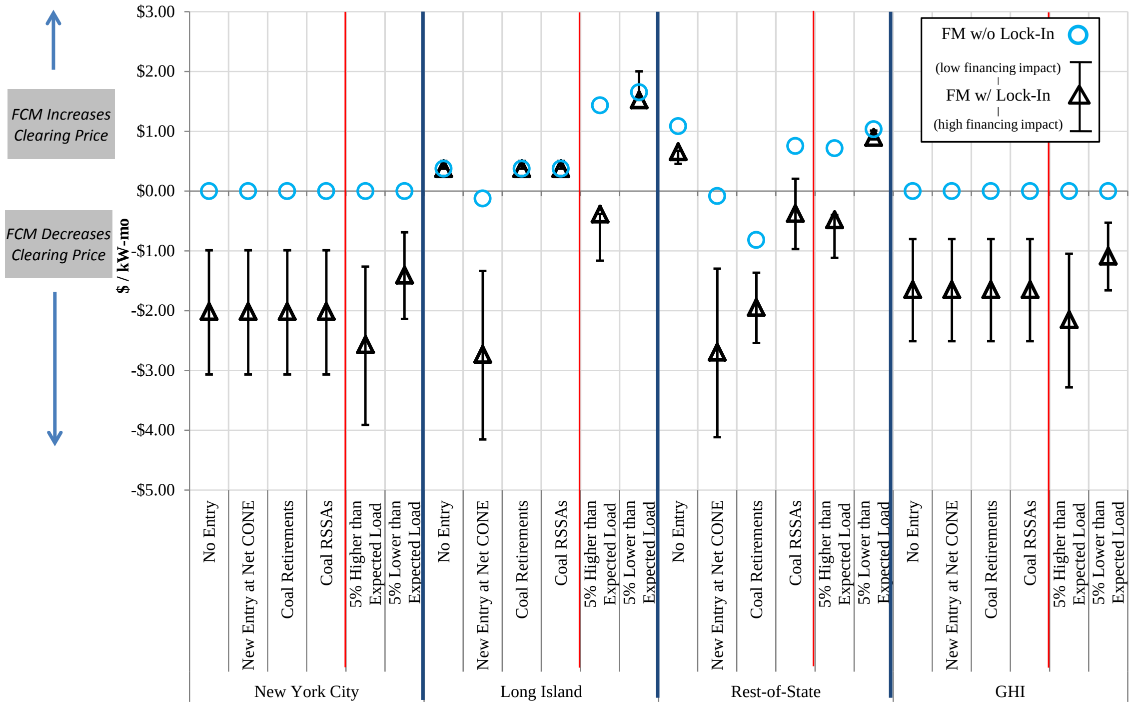


Figure 19: Change in Clearing Quantity (UCAP MW), By Zone ($2020)

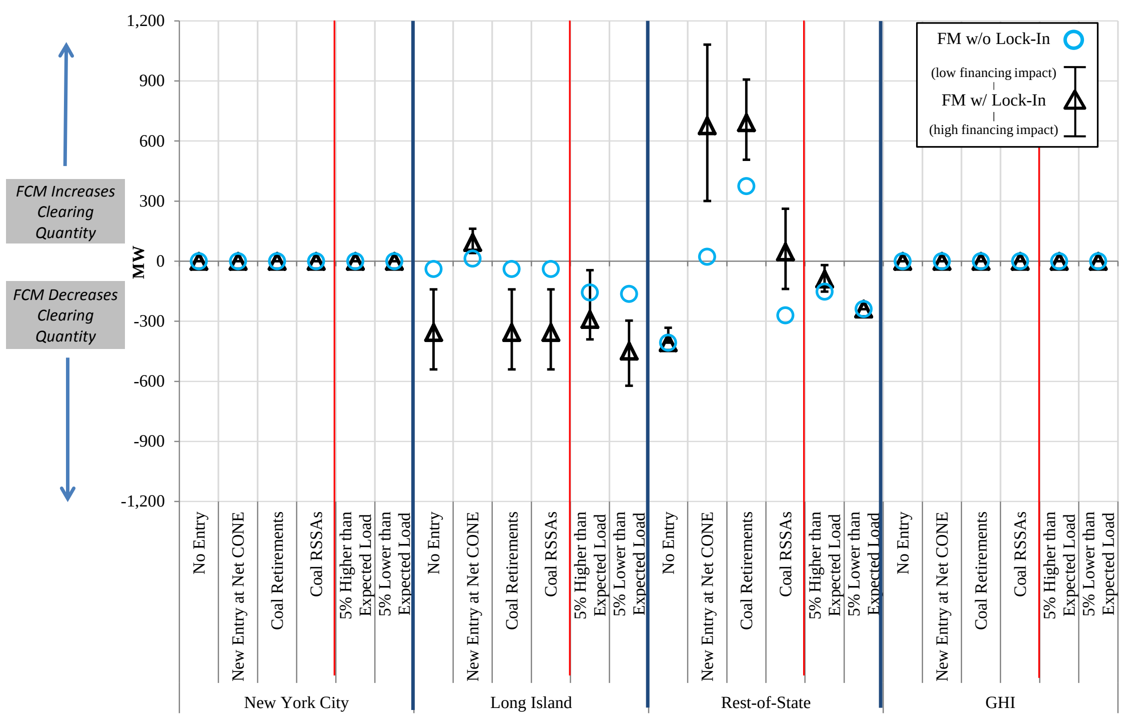


Figure 20: New Entry Clearing Quantity (UCAP MW) By Zone ($2020)

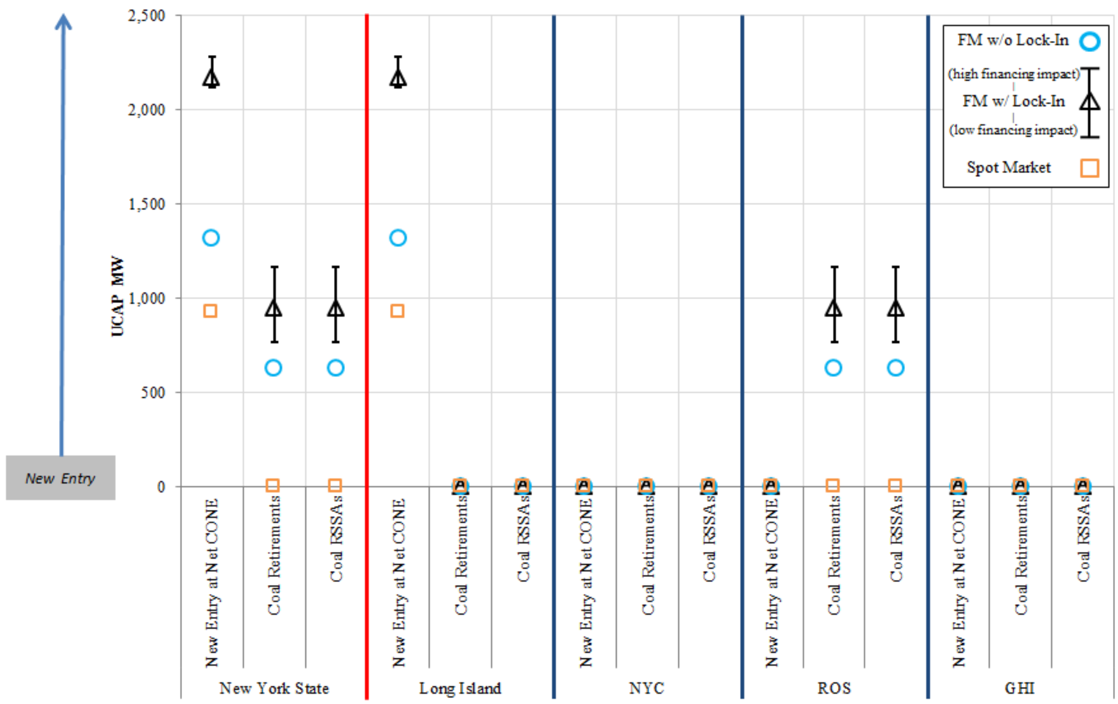


Figure 21: Change in Total Cost to Load By Zone ($2020)

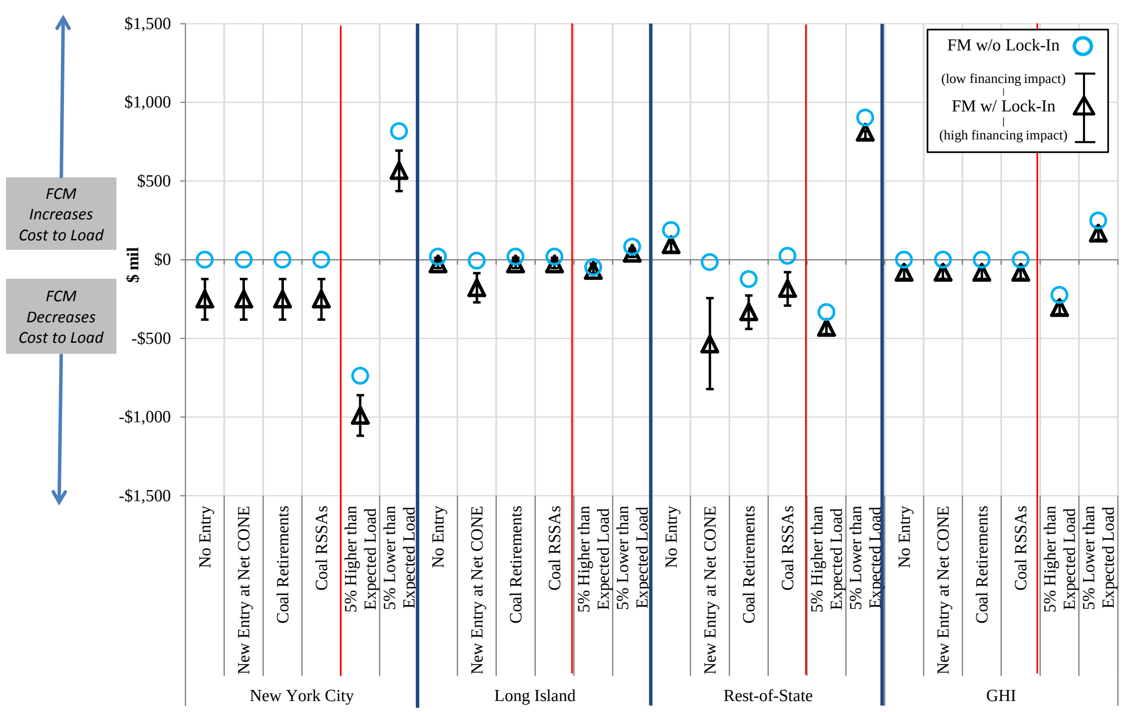


Figure 22: Percent Change (Relative to Spot Market) in Total Cost to Load By Zone ($2020)

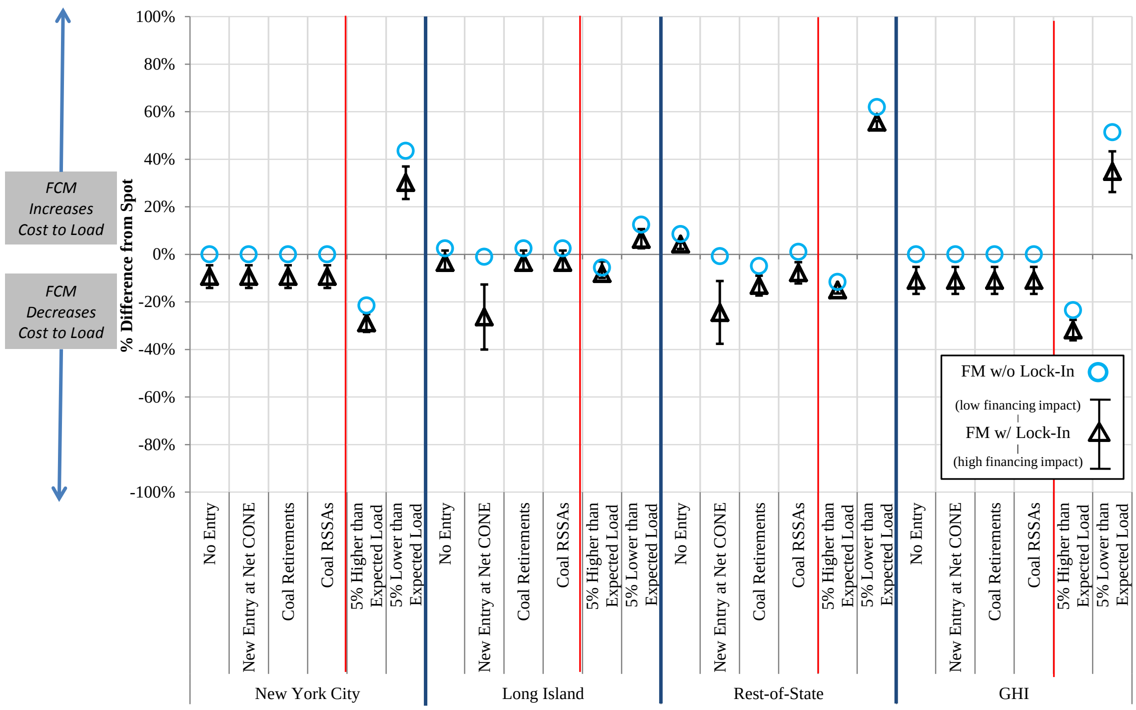


Figure 21 and Figure 22 illustrate the range of outcomes for the change in cost to load under the six scenarios, considering both a forward market with and without a lock-in expressed both in total dollars and relative to the total cost of the modeled spot market for the same scenario. Impacts are estimated as the difference between the forward market outcome and the spot market outcome, with percentages expressed relative to the spot market outcome. The total cost to load is calculated based on clearing prices and clearing quantities in each scenario. As illustrated in Figures 14-19, both price and quantity vary by scenario and by market construct.

In these figures, a negative cost to load means that the cost to load is *lower* in the forward market than the spot market, while a positive value means that the cost to load is *higher* in the forward market. The impacts evaluated by the capacity market model capture impacts in 2020, and, as discussed previously, may not capture all economic and reliability impacts. Throughout this report, changes in quantity and cost to load are reported for both New York State as whole and for non-overlapping zones (New York City, Long-Island, Zones G-I, and Rest-Of- State, defined as zones A-F). Similarly, it is important to note that historically, capacity payments have represented approximately 7 percent (Long Island), 10 percent (G-J and ROS), and 26 percent (NYC) of all-in energy prices.[83] Therefore, a 10 percent price increase (decrease) in total cost to load would be

[83] Potomac Economics. 2013 State of the Market Report for the New York ISO Markets, May 2014. See, for example, Figure 1 "Average All-In Price by Region".

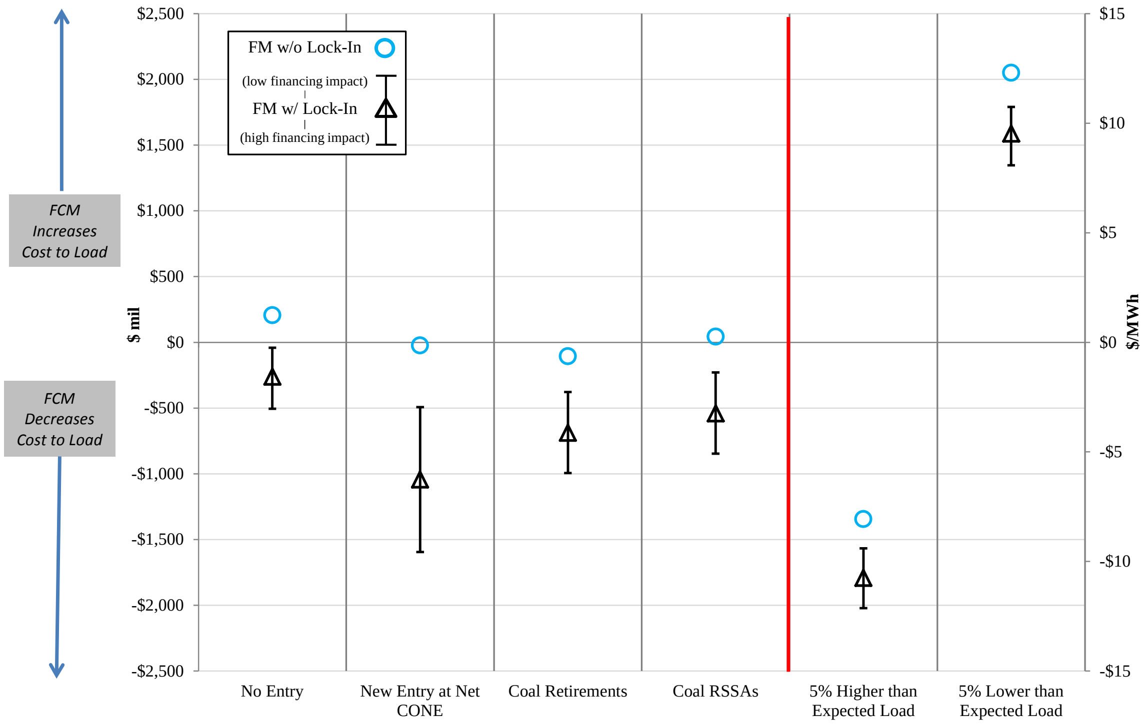
expected to increase (decrease) total all-in energy prices to consumers at a similar proportion. That is, for a hypothetical increase in cost of load to NYC customers, the all-in energy price would be expected to increase by 2.6 percent (10 percent * 26 percent).

In all scenarios, a forward market without a lock-in increases the total cost to load in all zones relative to a forward market with a lock-in. In NYC and Zones G-J, the reduction in total cost to load is driven entirely by the shift in the demand curve from the lower reference price. For the rest-of-system and Long Island, a forward market increases the total cost to load in all scenarios, except when there is higher than expected load growth. In this case, a forward market is able to procure a total quantity of supply at a lower cost than a comparable spot market auction. Of course, the reverse is the cost when the load growth is less than expected, and the forward market initially over-procures capacity. Later in the report, the implications of these scenarios for risk and expected costs to load are further assessed.

The cost to load for the rest-of-system differs, as expected, under the two coal retirement scenarios. The difference is driven by the additional out of market costs of the RSSA contracts in the spot market, which are included in the RSSA scenario. The difference also depends on the choice of a lock-in in the forward market, which impacts the cost of new entry assumed to replace coal retirements.

Figures 23 and 24 illustrate the cost to load impacts for all New York consumers. Without a price lock-in (such that there is no difference between the forward and spot market demand curve), the change in total generator payments ranges from a reduction of $105 million to an increase of $207 million (again, excluding higher and lower load forecast scenarios). Relative to the total size of the spot market for the same scenarios, these values represent a change of between -2 and 3 percent. With a price lock-in (and excluding the higher and lower load forecast scenarios), the reduction in total cost to load within New York State ranges from $1,043 million to $261 million evaluated at the mid-point financing assumption for a 7-year lock-in. Relative to the total size of the market, these values represent a reduction relative to the spot market of 4 percent to 17 percent.

Figure 23: Change in Total Cost to Load, All New York Consumers ($2020)

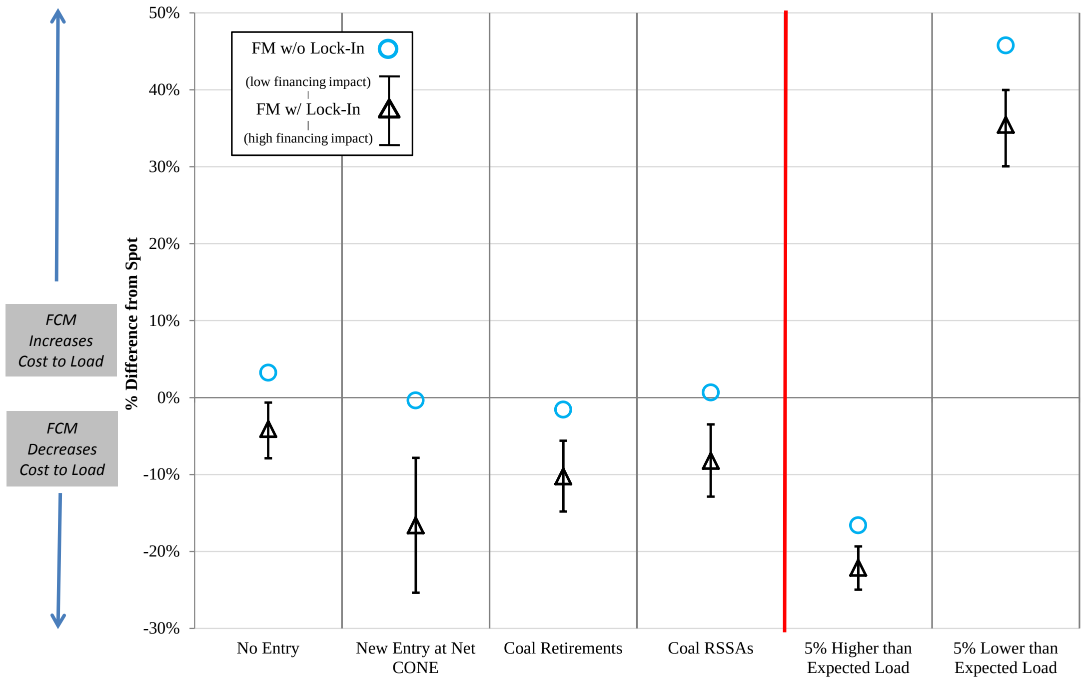


Including the higher and lower load forecast scenarios, the change in the total cost to load within New York State ranges from a low of -$1.8 billion to a high of $1.6 billion evaluated at the mid-point financing assumption for a 7-year lock-in. Relative to the total size of the market, these values represent a change from the spot market of -22 to +35 percent. On a weighted average basis, capacity costs have represented approximately 15 percent of all-in energy prices to consumers. Therefore, the total impact to all-in energy prices from a move to a forward market with a lock-in could be between -3.3 percent to 5.3 percent. The relative impact on a $/MWh basis is illustrated on the right axis of both Figures 23 and 24.

In contrast, without a lock-in and assuming no difference between the forward and spot market demand curve, the change in total generator payments ranges from a low of -$1.3 billion to a high of $2.1 billion. Relative to the total size of the market, these values represent a change from the spot market of -17 to +46 percent, or an all-in impact between -2.5 percent to 6.9 percent.

These results suggest that the potential costs (or benefits) from changes in load forecast are not symmetric, and that the costs from a lower than expected load are greater than the potential cost savings (relative to a spot market) from higher than expected loads. This finding is specific to the NYISO demand curves and estimated NYISO supply curves. In general, this relationship depends largely on the relative shape of the supply and demand curves, as further illustrated in Appendix III. Additionally, as discussed in Section 5, the *probability* for lower than expected loads (i.e., over-forecasting by the system planner) may be expected to be higher than the probability of under-forecasting.

Figure 24: Percent Change in Total Cost to Load, All New York Consumers ($2020)



1. *Additional Costs due to a Lock-In*

The decision to exercise the lock-in option will reflect many factors, including price risk and potential expected gains given differences between offer prices and expected future price. In particular, a lock-in may be used when future prices are expected to be lower than the first year clearing price. Therefore, over the life of a lock-in, the difference between actual clearing prices (including new generation bid as price taking units) and the locked-in price represent a capacity market "uplift" payment to new generation. For example, if capacity prices cleared at net CONE in each year for seven years, the NPV of capacity market revenues for a hypothetical 250 MW unit would be equal to $131,237. A 10 percent decline in capacity prices for each year 2 through 7 would increase the total payments under a lock-in by 8.3 percent. That is, without a lock-in for net CONE in years 1-7, the same unit would have been expected to earn 8.3 percent less.

In reality, the relative impact of this uplift payment will depend on the quantity of new capacity that elects to lock-in and the spread between the lock-in capacity prices and actual prices in years 2 through 7. In a forward market with a lock-in, new entry may have an incentive to "time" its entry to achieve the highest possible capacity price.[84] As a consequence, if market participants only lock-in prices when actual prices are expected to be below offer prices, uplift payments may be required in subsequent years.

Estimates of the potential uplift are reported in Figure 25 for the All Coal Retirement Scenarios described above (here, the analysis focuses solely on the impact of a lock-in within the FM. Both Coal Retirements scenario assume the same quantity of new entry, with the only differences being the presence of RSSAs in the spot market). In this case, all coal units retire in 2020 and 948 MW of new resources enter the market with offers at net CONE to replace the coal retirements. The impact of potential uplift is calculated by assuming that (1) all of these new resources lock-in price at net CONE and (2) clearing prices in years 2 to 7 range from -10 to 50 percent of future clearing prices (in increments of 10 percent). In 2021 to 2026, the future market clearing prices assume load growth and new resource supplies from the GE MAPS CARIS II database, but do not include any dynamic entry or retirement decisions given clearing prices in these years.[85] Thus, the results in Figure 25 illustrate the potential uplift associated with 948 MW of new resources. Estimated uplift under these assumptions range from 0.17 to 1.2 percent of the present value of total cost to load.[86]

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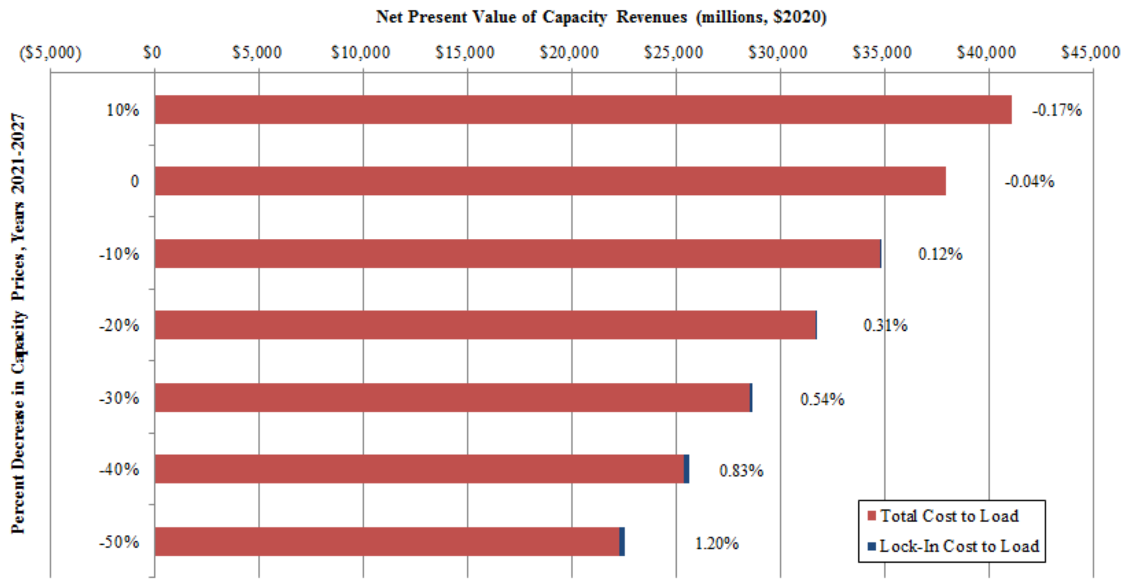
[84] Further, in a forward market there exists the possibility that generation fleet owners with multiple assets have asymmetric information regarding the timing of entry and exit bids.

[85] New CARIS II resources includes: 210 MW of CT in Long Island in 2021, 310 MW of CC in Zone G in 2022, 500 and 210 MW of CC and CT, respectively, in New York City in 2023 (including approximately 495 MW of retired Astoria GTs), 1,500 MW of wind in Western New York and 225 MW of solar in J and K in 2025. The analysis assumes that all new CARIS II resources do not affect clearing prices. See Duffy, T. 2014 Preliminary CARIS 2 Base Case Results, Presented to Electric System Planning Working Group, June 30, 2014. Available: http://www.nyiso.com/public/markets_operations/committees/meeting_materials/index.jsp?com=bic_espwg

The peak load forecast for each zone in years 2025 and 2026 used to set the demand curve is assumed to grow at the 10-year compound annual average growth rate for the period 2014-2024.

[86] Note that there is a small difference between the first year price (the lock-in price) and prices in subsequent years, such that the price lock-in by all new capacity results in a reduction in cost to load (loss of generator revenue) equal to $33 million (present value), or 0.09 percent of total cost to load.

Figure 25: Total Cost to Load, for Existing and New Resources in a FM Additional Payments for a Lock-In, All Coal Retirements Scenarios



Notes:
[1] Scenario assumes that all coal units (1,307 MW UCAP) retire in 2020 and are replaced by 948 MW UCAP of new entry. New Entry bids at $0/kW-mo in the spot market and clears at the reference price (net CONE) in the forward market.

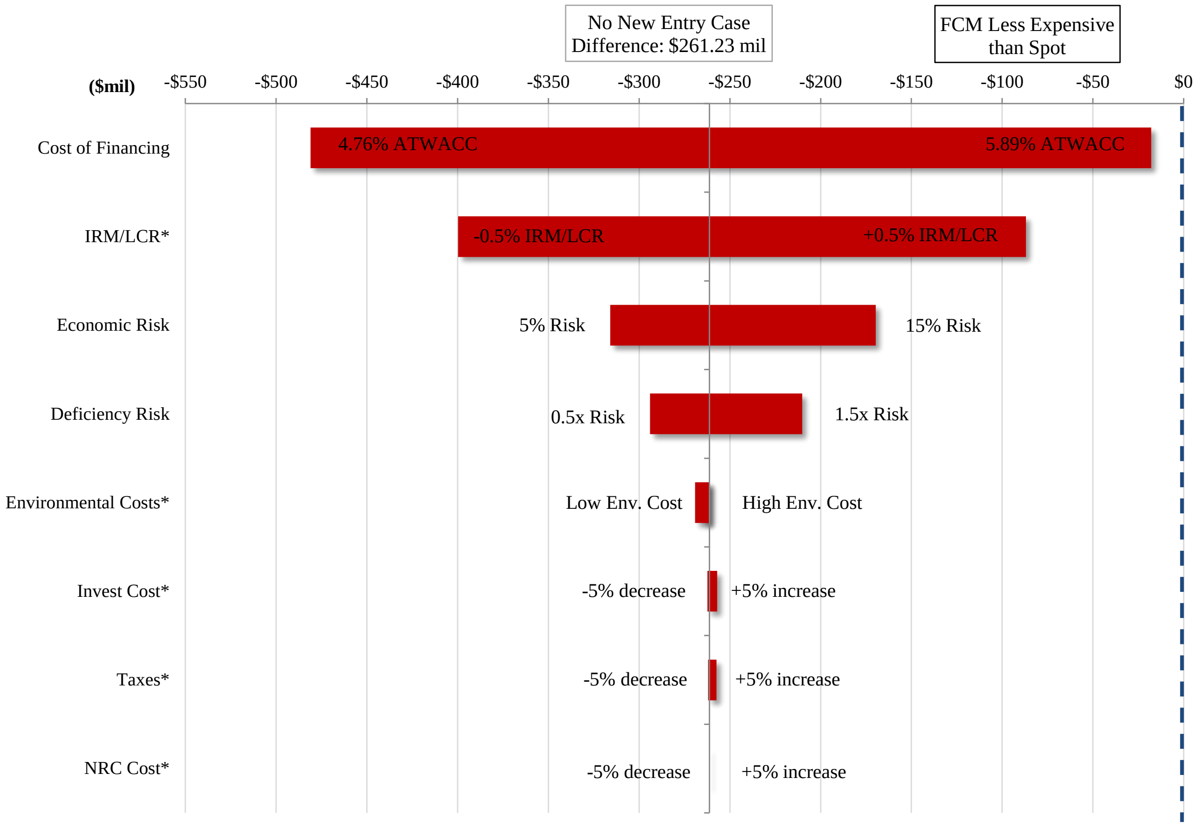
[2] Net Present Value is calculated using an after tax weighted average cost of capital of 6.37%.

2. Sensitivities

Within the current model, there exist at least two types of uncertainty. The first uncertainty relates to future outcomes of the New York energy markets. This uncertainty is addressed through scenario analysis that captures a likely range of outcomes. These outcomes provide a reasonable bound to expected outcomes. Based on feedback from stakeholders, NYISO, and Potomac economics, Figures18-24 illustrate the sensitivity of these results accounting for variation in cost of financing impacts and also, without a lock-in. As described throughout this report, a lock-in and its impacts to the reference unit in the demand curve reset process has the single largest impact on expected outcomes.

The second type of uncertainty relates to parameter uncertainty in the model. Sections III.C and III.D describe the key model inputs related to possible and quantified impacts to a forward market supply and demand curve, respectively. Appendix I describes the underlying parameters used to construct the spot market supply and demand curves. As expected, model results also vary with respect to these parameters. Figure 26 represents the change in expected outcomes for a wide range of parameters. Parameters that affect both the spot and forward market are indicated with an asterisk (*). Modeled ranges for low/mid/high do not represent a forecast for expected outcomes. In contrast, they were developed through discussions with NYISO and are intended to highlight potential variation in model results.

Figure 26: Sensitivity Analysis, No New Entry Scenario



Note: * Indicates parameter that is held constant in both the SM and FM.

As expected, model results are most sensitive to the parameters that directly affect the forward market supply or demand curve. This includes the cost of financing impact for a 7-year lock-in and the deficiency and physical commitment risk that increases costs for existing supply.

Assumptions for parameters that affect both the spot and forward market have little impact on the evaluation of differences. This includes model sensitivities for taxes, investment costs, and environmental retrofit costs (including estimated NRC compliance costs).

Model results are also sensitive to small changes in the IRM and LCR targets. As discussed in Section IV.C.3, a forward market will tend to have greater load forecast uncertainty three years out than a spot market forecast set one year out. Load forecast error tends to increase IRM values. Similarly, as discussed in Section IV.C.1, a forward market may increase fleet turnover and accelerate retirements of older, less efficient generating units. The addition of new, more efficient generation will tend to lower the system average EFORd, which decreases IRM. It is difficult to predict the relative magnitude of these changes, but on net, they may be expected to offset one another such that

IRM values are likely to remain the same under both market structures. In practice, the final demand curve reference requirement is a function of both the load forecast and the IRM target. A change in either parameter, while holding the other constant, leads to a change in the final absolute MW reserve requirement. In operation, both parameters are adjusted annually to arrive at a final requirement, and offsetting changes can be made in the IRM to account for changes in load forecast.

A 0.5 percentage point increase (decrease) in the IRM/LCR shifts out the forward market demand curve relative to the spot curve. This increases (decreases) the total cost to load in the forward market and reduces (increases) the relative difference in cost to load compared to the spot market. In the no new entry scenario, a 0.5 percentage point increase in the IRM from 117 percent to 117.5 percent increases the total cost to load in the FM by $174 million; the net difference between the forward and spot markets is reduced from -$261 million to -$86 million.

IV. EVALUATION OF KEY MARKET DESIGN QUESTIONS

In this section, we evaluate the likely impact of a switch in NYISO's ICAP market from a spot to a forward market structure. We also consider a forward market structure in which new resources have the option to lock-in first-year prices for a multi-year period. This evaluation incorporates empirical findings from our modeling analysis, assessment of the performance of capacity markets to date, and economic and engineering fundamentals. We conclude with certain recommendations for NYISO going forward.

A. Evaluation Framework

Our evaluation framework considers three broad sets of factors related to reliability outcomes, economic outcomes, and institutional factors. The first set of factors relates to the effectiveness in supporting or achieving **reliability objectives**. In the context of a capacity market, the primary objective is resource adequacy, but also includes other aspects of reliability, such as voltage and stability at the local or system level. A well-designed capacity market should operate to secure an adequate supply of resources to maintain reliable operations. Economic factors are also important. A well-designed capacity market should encourage an efficient level of resources, reflecting both the cost of new resources and the associated reliability risks, given the underlying value of lost load. Along with ensuring an appropriate quantity of resources, markets should also create incentives for a level of resource performance that reflects an appropriate balance between the cost of performance-improving measures and improved reliability (in terms of avoiding loss of load).[87]

The second set of factors relates to market or **economic outcomes**. These factors reflect the objective of developing economically efficient markets, as well as economic impacts to particular groups. In particular, a capacity market should encourage efficient resource decisions that reflect the true economic costs of alternative resources to supplying resource adequacy, including new and existing generation resources, imports and demand response. Other economic outcomes with implications for both efficiency and impacts include price stability, risk allocation, reliance on out-of-market solutions, and costs to load.

The third set of factors relates to **administrative, institutional and regulatory factors**. These factors reflect the implications of the switch in market structure for market administration and institutional requirements, and the regulatory process. In particular, we consider system operator administrative costs, ability of the market design to provide flexibility to address emerging issues in a timely fashion and implications of rule-making and stakeholder processes.

Using this three-level framework, we evaluate the changes of the NYISO capacity markets

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[87] Schatzki, Todd, "Quality *and* Quantity," presented at the Center for Research into Regulated Industries, Western Conference, 2013.

under consideration based on the factors that are summarized in Table 8. Note that there are many inter- relationships between these factors. For example, resource performance has implications for reliability and economics, although we have included it under reliability factors. The right-hand column in Table 8 clarifies these inter-relationships by identifying all of the underlying objectives affected by each of the factors we consider in our evaluation.

Table 8: Capacity Market Evaluation Criteria

Reliability Factors
Maintaining Resource Adequacy and Reliability
Resource Supply to Support Reliability
Demand Curve Driven Shifts in Resource Supply
Physical versus Financial Forward Commitments
Resource Performance
Regulatory Flexibility
Economic and Market Factors
Efficient Capital Decisions • **Implications of a Forward Market** • **New Resource Non-Scalability** • **Implementation of a Price Lock-In** • **Season Variation in Resource Needs and Supplies**
Reliance on Regulated Solutions
Risk Allocation
Cost to Load
Administrative, Institutional, and Regulatory Factors
Administrative (NYISO) Costs
Timing (to Implement Market Changes)
Stakeholder and Regulatory Process

B. Implications for Reliability

In this section, the analysis considers potential impacts of a forward market and a price lock-in on reliability outcomes. The switch from a spot to a forward market has a number of potential implications for reliability. By comparison, most of the impacts described below are unaffected by the decision to adopt a price lock-in.

1. Maintaining Resource Adequacy and Reliability

The change from a spot to forward capacity market construct would not fundamentally change the ability of capacity markets to support resource adequacy within the NYISO planning framework. However, the switch to a forward capacity market could affect reliability through several channels. Below we consider several potential channels:[88]

- The timing of information about retirements and other resource supplies, such as demand response and imports, which can affect the timing and options for reliability solutions needed to unanticipated reliability needs;
- The supply of resources available to meet reliability needs through the capacity market;
- Demand curve changes that lead to changes in quantities clearing the market;
- Physical rather than financial commitments;
- Performance incentives; and
- Regulatory timing and flexibility.

a) Information about Retirements

With a forward market, information about resource supplies is developed further in advance of the delivery period. As a result, unanticipated changes in supply may be signaled at the time of the forward auction, typically three years prior to the delivery period. Earlier information about retirements has potential consequences for how reliability is maintained in response to the retirement of generating resources.

Under the current spot market, existing generation resources 80MW or larger must give at least

[88] "The goal of the three year forward requirement is to provide for competition from new entry, to provide an opportunity to market test decisions to invest in existing units, to provide for advance decisions about unit retirements and to provide for a window to resolve reliability issues revealed in market outcomes before they occur. In each case, the three year forward requirement provides for more competition in a market for long lived assets that require years to build or modify." Bowring, Joseph, 2013, "Capacity Markets in PJM," *Economics of Energy & Environmental Policy*, Vol. 2, No. 2.

180 days advance notice of the retirement to the PSC.[89] When notice is given, NYISO initiates an evaluation of whether the resource is needed for reliability purposes. If it is determined that the resource is needed for reliability purposes, negotiations are undertaken for the resource to operate under a Reliability Support Services Agreement (RSSA), under which the resource can remain in operation for reliability support through a cost-of-service agreement. In principle, a RSSA can be implemented to address any reliability need, including resource adequacy. In recent years, RRSAs have been implemented, with local reliability posited as the primary rationale. These agreements include the Dunkirk,[90] Cayuga,[91] and Ginna[92] facilities. Other approaches have been taken to address potential retirement risks. For example, the Energy Highway Blueprint proactively called for up to a $2 billion investment to consider the repowering of 750 MW of older power plants on Long Island.[93]

Under a forward market, existing resources that did not clear in the forward market would not have an obligation to supply capacity. Such resources could continue to operate without a capacity supply obligation, mothball capacity, or retire as of the delivery year. Under any of these circumstances, NYISO can initiate a process to determine whether the loss of the resource poses reliability concerns and to identify potential solutions if such concerns are present.

While providing advance warning of potential retirements when a resource does not clear in the forward auction, a forward market does not eliminate the possibility that a resource seeks retirement with relatively short notice. Resources that clear in a forward market and accept a CSO still have the option to sell back their CSO in subsequent balancing auctions or simply retire and incur deficiency penalties. However, under most circumstances, it is most likely that resources would only exercise this option under circumstances such as an unexpected and significant change in plant operating conditions or costs (e.g., a major forced outage) or an excess of resource supplies (given demand).[94]

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[89] Generators less than 80 MW and greater than 2 MW must give notice of at least 90 days before retiring, while resources 2 MW and less are exempt from notification requirements. NYISO, "Generator Retirement Procedure," Technical Bulletin 185, September 13, 2011.

[90] Petition of Dunkirk Power LLC and NRG Energy, Inc. for Waiver of Generator Retirement Requirements. Order Deciding Reliability Need Issues and Addressing Cost Allocation and Recovery. Case 12-E-0136, Issued and Effective May 20, 2013.

[91] Petition of Cayuga Operating Company, LLC to Mothball Generating Units 1 and 2. Order Deciding Reliability Need Issues and Addressing Cost Allocation and Recovery. Case 12-E-400, Issue and Effective January 16, 2014.

[92] Petition for Initiation of Proceeding to Examine Proposal for Continued Operation of R.E. Ginna Nuclear Power Plant. Order Directing Negotiation of a Reliability Support Service Agreement and Making Reliability Related Findings, Case 14-E-0270, Issued and Effective November 14, 2014.

[93] New York Energy Highway Blueprint, 2012, at page 76.

[94] As we discuss below, the reliability of information about whether resources will continue to offer supply is diminished when forward procurements are based on a biased, conservative expectation of future loads. When excess supply is procured in the forward market due to a conservative estimate of the IRM, the expected cost of selling back a CSO is diminished, thus increasing the likelihood that resources will retire in subsequent rebalancing auctions.

In principle, greater advance notice about retirements can potentially improve reliability outcomes through several channels:

1. *Time Available to Develop Reliability Solutions.* With greater lead time, the NYISO, the PSC and market participants have more time to develop appropriate reliability solutions. With more time, there is greater opportunity for solutions to be developed in a careful and deliberative fashion that affords input and information from all relevant parties. Such a process can lead to more effective and less costly solutions, and reduce organizational burdens on the NYISO, the PSC and market participants.
2. *Options Available to Mitigate Reliability Concerns*. With greater lead time, there is potentially a broader set of solutions available to address reliability concerns. As result, more reliable and cost-effective solutions may be implemented.
3. *Duration of RSS Agreements.* With earlier information, the duration of any RSSA needed to address a reliability concern may be reduced. For example, if a transmission solution needed to address reliability concerns requires four years from the time when the need is identified to when the solution is in service, then the RSSA required could be as short as one year in comparison to a four year RSSA under the current market construct. Recent RSSA's have required that resources offer capacity under the agreement into the spot market as a price taking resource, which can distort pricing.[95] Consequently, a shorter-duration RSSA's can reduce the risk of this adverse outcome for market pricing.
4. *Leverage in RSSA Negotiations.* With more solutions available and more lead time, the leverage that the resource owner has in negotiations with the NYISO and PSC over the terms of the RSSA can be diminished. As a result, the terms of the RSSA agreement may be more favorable than those negotiated if a resource needed for reliability retires with limited notice under the current market construct.

While a forward market may improve reliability outcomes (at a lower cost to load and with greater reliance on market-based solutions), as noted above, a forward market will not provide advance notice of retirements under all circumstances (unless the PSC's mandatory advance notice requirement is extended to require earlier notification, a change that could also be implemented under the current spot market).[96] Moreover, while a forward market could provide some benefits, there is no reason to think that the current market construct would lead to *unreliable* outcomes, particularly in light of the option to prolong the operation of existing resources seeking to retire through RSSAs. To the extent that there is willingness by regulators to continue to rely on these options when needed, the likelihood that system or local reliability in NYISO will be compromised is significantly diminished.

[95] See, for example, recent RSSAs with Dunkirk (Case 12-E-0577) and Cayuga (Case 12-E-0400). The decision about how resources supported by an out-of-market agreement (or price lock-in) are treated in the offer curve has implications for both efficient pricing and cost to load.

[96] Note that comparisons between reliability outcomes in NYISO and those in ISO-NE and PJM must consider differences in backstop reliability options that can be taken regulated utilities in these markets, which may support improved reliability.

The likelihood that a forward market will lead to useful information on resource retirement depends to some degree on the operational and economic factors that drive resource retirement decisions. These factors can include fuel prices (which affect resource competitiveness), mechanical age and depreciation, unexpected major operational failures and costs associated with regulatory compliance, particular with new or more stringent environmental regulation. When factors can be known in advance, a forward market can facilitate improved information about retirement timing. For example, resources that need to make large, anticipated capital investments to continue economic operations will be in a better position to plan for such changes, particularly when they are driven by compliance with environmental, safety and security regulations. At present, cooling water intake standards under Section 316(b) of the Clean Water Act, more stringent post- Fukushima security regulations for nuclear plants, and various air quality regulations potentially affect decisions within New York. The NYISO estimates that up to 33,200 MW of summer capacity could be affected to some extent by these regulations, with 13,650 potentially facing significant operational impacts. These units include all coal units, nuclear units, including Indian Point, and several large oil and gas steam turbines.[97]

Even with a forward market, the timing of information about potential retirements can impose limits on the ability of developers to respond with new resources. For example, if offers from new resources and de-list offers from existing supply are submitted at the same time, developers may not have information about retirements that would allow them to submit offers in a timely fashion to address resource gaps. Thus, depending on market design and market conditions, the developer response to resource retirements may not be simultaneous with retirement decisions. A lag in offers would be most likely to occur in the event that there is a larger than normal quantity of non-price retirements (i.e., retirements to be made at any price). For example, without some signal prior to forward market, the market might not respond with sufficient new resources in the same auction to offset the loss of an unusually large resource, such as Indian Point (over 2 GW). Consequently, in the case of large resource retirements, some advance signal about retirement can help ensure that the market is aware of the potential opportunity for a resource gap.[98]

In other cases, a forward market may provide less or no opportunity to respond to factors driving retirements. One such case is when a retirement occurs due to major mechanical failures that require significant capital investment to bring the plant back into operation. Under these circumstances, because the mechanical failure or accident is not known in advance, a forward market provides no opportunity for improved information. Thus, for example, a forward market would not have facilitated a reliability response to plant damages incurred at the Astoria and Ravenswood plants as a result of Hurricane Sandy.

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[97] NYISO, "2014 Reliability Needs Assessment", Table 5-5 and 5-6.

[98] For example, in a recent ISO-NE capacity auction, several resources submitted non-price retirements after offers from new resources were submitted. Because resource suppliers had anticipated excess supply, few offers for new resources had been submitted. Consequently, there was little competition from new resources to fill the gap in demand for capacity.

An alternative approach to improving the timeliness of retirement announcements is to lengthen the retirement notification period, which is currently set at 180 days for units 80MW and larger and less time for smaller resources. While imposing a longer notification period would improve information about resource retirements, it would also raise costs to resources by limiting resource owner's options to change economic decisions about resource use in response to new information about market conditions, including prices and the decisions of other resources in the market. For example, if the retirement notification period were set at 3-years, a coal-fired resource that decides to retire as a consequence of unfavorable market conditions (e.g., low natural gas prices) may find that it economically profitable to reverse that decision if market conditions subsequently become more favorable (e.g., higher gas prices leading to higher power prices). Under a forward structure, such a resource preserves the option to mothball its capacity and offer supply into the market in subsequent auctions.

b) Resource Supply to Support Reliability through the Capacity Market

A switch from a spot to forward market structure has many potential implications for the ability of various types of resources to supply capacity through the organized market, and the costs of such supply. These implications have consequences for both the reliability outcomes achieved through the capacity market, and the costs associated with those supplies. In particular, within a forward market, a larger set of resources compete to supply, which can mean there is greater responsiveness to known changes in resource needs. In this section, we focus on the ability of different types to supply capacity given the differences in timing between a forward and spot market. In later sections, we further discuss the implications of such timing for economic costs.

(1) New Resources

A forward market allows new resources to compete with existing resources to supply capacity. As a result, capacity to replace resources seeking to retire (through high bids or through non-price retirements) can be supplied through the same auction in which retirements occur. By lowering financial risk, a price lock-in may increase the number of new resources willing to supply through the NYISO capacity market revenues. By contrast, in the spot market, new resources must make entry decisions prior to participating in the market. As a result, new resources begin the multi-year development process in anticipation of a retirement decision (that may never materialize) or after the actual resource retirement occurs.

(2) Demand Response

The ability of demand response providers to supply resources and their responsiveness to unanticipated resources shortages – and associated changes in prices – differ between a spot and forward market. Demand response providers develop resources through individual contracts with customers willing to curtail or shift loads when requested. The ability of these providers to adjust the quantity of resources supplied is limited by the practical considerations of re-arranging contractual terms with existing customers and developing new customers. Moreover, providers must continuously adjust to customer circumstances, which may result in a curtailment of supply (e.g., when firm goes out of business) or an increase in supply (e.g., if a firm changes production process or expands).

Given these limits to contracting for demand-response, the (long-run) supply of these resources supplied in a spot and forward market could differ. Within a forward market, demand-response resources need to commit to a supply of resources over a time period in which it is impossible to contract with underlying resources for these commitments. Consequently, demand response providers provide capacity guarantees while accepting the risk that providers will be unable to find willing customers at prices consistent with offered supply. In principle, this risk could dampen the supply of demand response resources offered into forward markets.

In practice, the supply of demand response in ISO-NE and PJM forward markets has been quite robust, particularly in the initial auctions for each commitment period. However, in subsequent rebalancing auctions, a large fraction of the demand response clearing in the initial auction has been replaced by other capacity, which has raised concerns about whether such resources are offered as physical supply or financial offers. In spite of the churn in resources from initial auction to the delivery period, demand response constitutes a large fraction of the final supply of resources taking on capacity obligations. Consequently, while a forward market may raise the cost for demand response to participate in capacity markets, it does not appear to limits the ability of these resources to supply capacity.

The response of demand resources to unanticipated shortages – and associated changes in prices – may also differ between a spot and forward market. A difference could emerge because of the time available for DR providers to respond to changes in prices. With a forward market, because there is a three-year lag between market-clearing and delivery, demand response providers have more time to adjust customer contracts in response to the actual supply that clears.[99] By contrast, the supply that demand response providers can offer in a spot market is relatively fixed from month-to-month because of the practical limits discussed above. As a result, there is limited ability to immediately increase supplies in response to an increase in prices, although supply could develop over time. Consequently, the ability of demand- response providers to increase supply significantly in response to unanticipated changes in prices is more limited than in the forward market.

(3) Imports and Exports

Because the NYISO operates a spot capacity market, import and export capacity decisions are currently made after all resource decisions are made in its neighboring markets. Resources in the

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[99] The means by which resources can vary the quantity of supply offered for the level of price differs across auction designs. With the descending clock auction used in ISO-NE, market participants can vary supply in each round as the price declines. With a sealed bid auction, resources can offer different blocks of supply at different prices.

northeast ISOs (ISO-NE, NYISO and PJM), when making import/export decisions, will offer supply into ISO-NE and PJM forward markets given their expectation of capacity revenues that could be earned from supplying into NYISO's spot market. Along with these price expectations, these decisions will reflect the potential complications and costs involved with supply imports, particularly securing firm transmission across the intertie and the limits on these interchanges. [100] Transmission resources are generally available on a non-discriminatory basis, although there are some transmission resources, particularly unforced capacity deliverability rights (UDRs), over which certain market participants have exclusive access.

So long as resources can develop accurate expectations about capacity prices in NYISO, in principle, resources are unlikely to bias "long-run" (three year ahead) supply decisions away from NYISO markets. The decision to supply into one neighboring forward markets (ISO-NE or PJM) or *plan* to supply into the NYISO market will depend on several competing factors. On the one hand, because of the costs associated making a forward commitment (e.g., deficiency risks and loss of optionality), market participants may prefer to supply resources into NYISOISO-NE. On the other hand, clearing in the forward markets allows resources to lock-in prices which can mitigate certain financial risks in comparison to uncertain prices in the NYISO markets. On net, we do not expect a decision to shift to a forward market would significantly alter such three-year-ahead import and export decisions.

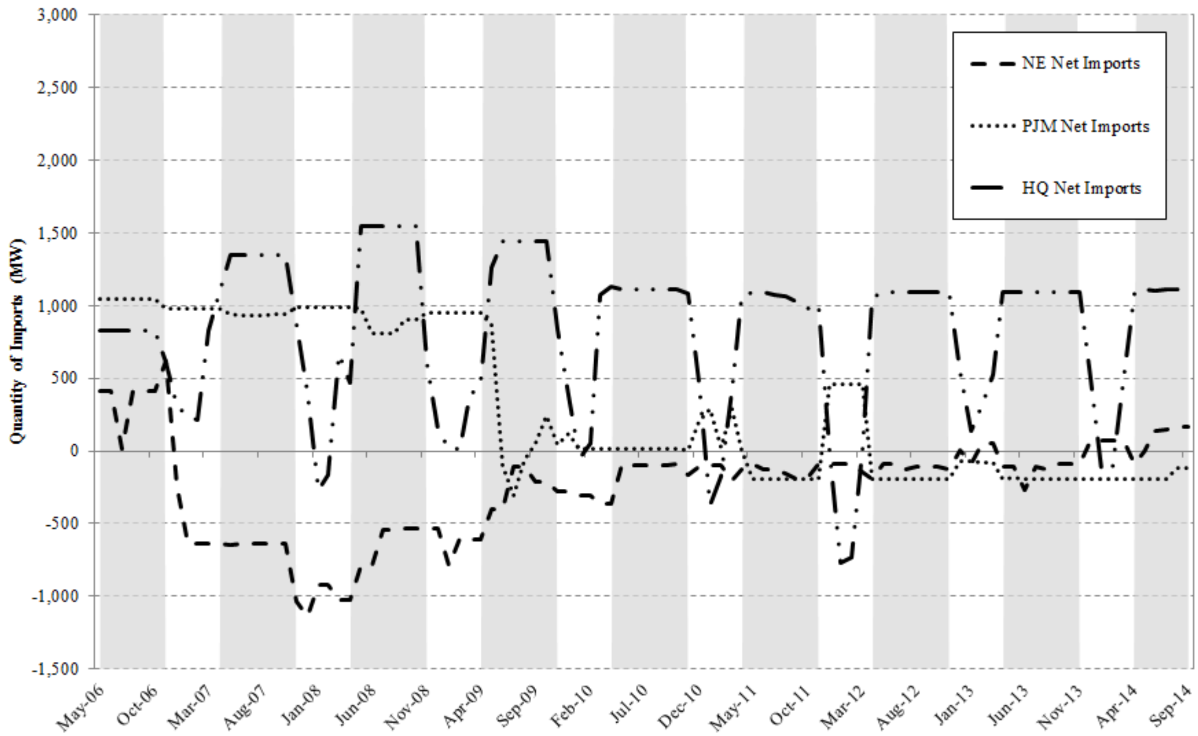
However, in principle, by clearing supply after all other regions, the NYISO could see less short-run responsiveness of import supplies to capacity prices (i.e., less price elasticity), because many resources that could potentially supply into the NYISO market would already have locked in obligations in ISO-NE and PJM. Potential supplies from HQ may also exhibit relatively little price responsiveness due to the nature of regulation in these regions.[101] As a result, should capacity supplies tighten due to unexpected retirements or other factors, the ability of imports to increase supply in response to price (within the bounds of physical limits on interties and zones) would be limited. Moreover, adjustments to import/export decisions could take several years because of the 3-year ahead forward commitments made in ISO-NE and PJM.

In practice, the additional short-run price responsiveness that the NYISO would expect to gain through improved market coordination with ISO-NE and PJM could be limited. At present, transmission resources impose limits on the amount of trade that can happen between regions. Including grandfathered rights, external transactions with neighboring regions are limited to 1,110

[100] For example, to import capacity, suppliers must demonstrate deliverability to the NYCA intertie and provide assurances from system operators in which the resource is located that exports will not be recalled or curtailed to satisfy local load. NYISO ICAP Manual, pages 4-29, 4-44 to 4-45.
[101] In HQ, resources are controlled by the Crown Corporation, which would certainly place a high value on ensuring resource adequacy in its region. Currently there are no potential import rights to deliver supply into NYISO from IESO. ICAP Manual, pages 4-47.

MW from HQ, 1,080 MW from PJM and 300 MW from ISO-NE.[102] In addition, there are 1,635 MW of UDRs from PJM and 330 MW of UDRs from New England.[103] Figure 27 shows historical net imports from each of these regions across these interfaces. During summer months, transmission limits appear to bind supplies from HQ. For ISO-NE and PJM, import/export capability is not fully utilized, although the amount of incremental supply that could be gained appears limited.

Figure 27: NYISO Net Imports (UCAP MW) by Region



Notes:
[1] Shaded periods are summer months.
[2] Net imports are calculated as NY Imports - NY Exports.

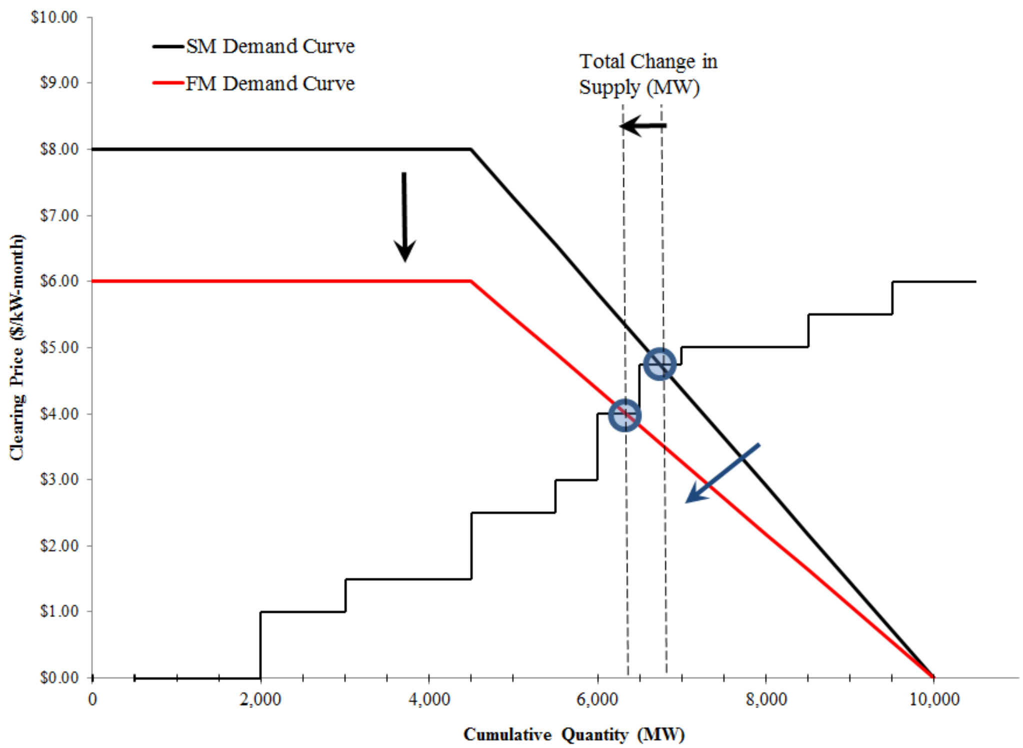
Consequently, the amount of supply shifting between ISO-NE, NYISO and PJM in response to changes in prices is currently somewhat limited. Were opportunities for inter-regional trade in supply to grow over time (e.g., with greater inter-regional price differences), the potential benefits from coordination of the markets between the three eastern ISOs would increase. Fully exploiting these opportunities would require changes to both physical infrastructure (e.g., new transmission) and market rules. However, the potential increases in supply from the shift to a forward market are likely to be somewhat limited in the short-run.

[102] ICAP Manual, pages 4-46 to 4-47.
[103] ICAP Manual, pages 4-47.

c) Demand Curve Driven Shifts in Resource Supply

The proposed changes in capacity market design could lead to a shift in the administratively determined demand curve. As discussed in Section III, a price lock-in could lead to an inward shift in the demand curve. Shifts in the demand curve can lead to corresponding shifts in the supply of resources, all things equal. For example, if a forward market with a price lock-in were to lead to an inward shift in the demand curve, then the supply of resources that would receive capacity payments would be diminished. Figure 28 illustrates this effect. As discussed, this inward shift in demand does not reflect a reduction in the underlying value of capacity, but it a feature of the administrative procedure for setting the demand curve.

Figure 28: Illustrative Change in Supply of Resources that would receive Capacity Payments, given an inward shift in the Demand Curve



d) Physical Versus Financial Forward Commitments

Unlike the two- settlement designs used in energy markets, forward capacity markets are designed to procure physical, rather than financial, commitments. Capacity markets use certain mechanisms to ensure that resources are willing and able to deliver on capacity obligations, including eligibility and auditing requirements to demonstrate the ability to physically deliver offered supplies, penalty mechanisms to ensure that there are financial consequences for a failure to deliver, and financial requirements to ensure that penalties can be fulfilled, if imposed.

Within a spot market structure, because there is limited time between market clearing and delivery, the risk that resources will be unable to deliver on (audited) supplies is small and the benefit to financially speculating is minimal. In a forward market, with three years or more between commitment and delivery, these factors potentially become more important considerations. Recent market outcomes in PJM's RPM have led to concerns that resource offers in initial forward auctions have not been backed by physical supply, which could compromise reliability.[104] These concerns have emerged because a large fraction of resources that have cleared in the initial forward auctions have subsequently been replaced by other resources in rebalancing (incremental) auctions. Replacement has been particularly high for demand resources. Between 2009 and 2013 commitment periods, replacement of demand response resources that initially cleared ranged from 44 to 72 percent of initial cleared quantities.[105] For the latest PJM RPM obligation period of 2014-2015, the initial cleared quantity of demand response was 9.07% of capacity, but the final quantity of demand response after reconfiguration auctions was only 6.06%.[106] Given the reduction in price from the initial to the later balancing auctions, which has been a consistent trend across commitment periods, resources have been able to earn profits without any delivery of supply.

These outcomes have raised questions about the nature of commitments within a forward capacity market. Because the reliability of delivered capacity is ensured through a combination of auditing requirements *and* financial incentives (payments and penalties combined with financial assurance), the consequences of financial offers (that is, offers not backed by real plans to develop resources) for PJM reliability is unclear. While the market exhibits substantial churn of commitments between the initial auction and commitment period, some churn is no doubt beneficial because it permits resources that are unable to meet their obligations to find resources that can fulfill the obligation. That said, financial offers create the risk that the obligation will not be backed by a physical resource during the commitment period, thus impairing reliability. The implications of such behavior for reliability in a given market will depend on many factors, such as the size of the market, available resources, including imports, and the scope of the speculative activity. Sufficient financial incentives for capacity delivery are important to creating incentives that avoid this risk.[107]

Concerns about speculative offers can also be mitigated through market design and implementation. In particular, conservative forecasts of installed capacity requirements that over-procure in the initial auction relative to the final requirements will tend to encourage speculative behavior because there is an opportunity in rebalancing auctions to profitably sell out financial

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[104] Monitoring Analytics, "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2013," September 12, 2013.
[105] Monitoring Analytics, 2013, Table 9.
[106] PJM 2014-15 Base Residual and Incremental Auction results.
[107] Along with financial assurance, the ability to continue operation in energy and ancillary service markets represents a critical incentive for market participants to fulfill with resource obligations.

positions taken in the initial forward auction.[108]

e) *Performance Incentives*

The NYISO capacity markets currently have a number of mechanisms in place to ensure that resources perform when needed to maintain reliable system operations. Energy and ancillary services markets provide revenues that generally increase during periods of high loads when available supply resources are limited. Shortage pricing further supports these incentives by raising prices to levels consistent with the value of lost load when there is a deficiency of operating reserves. The NYISO also imposes penalties on resources that fail to perform according to offered supply specifications.[109]

The NYISO is currently investigating the need for modifications to these performance incentives, and, if so, what mechanisms would be best suited to the design of its energy, ancillary service and capacity markets.[110] ISO-NE has recently instituted changes to its capacity market (through a so-called "Pay for Performance" mechanism) designed to enhance incentives for performance.[111] PJM has recently filed proposed capacity market changes aimed at enhancing performance incentives at FERC.[112] The NYISO is considering several potential changes to improve performance incentives, including enhancements to shortage pricing and a mechanism that would provide additional incentives based on actual resource performance.

All of these mechanisms for creating performance incentives rely on actual operational performance in energy markets, rather than actions taken prior to energy market operations. As a result, the design of the capacity market will have no direct impact on the performance of resources in response to these incentives or the actions taken by resources to improve resource performance.

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[108] Speculative behavior may also have implications for economic outcomes, although the effect will depend on the particular circumstances driving the speculative behavior. For example, to the extent that speculative behavior is driven by over-procurement in initial auctions, outcomes in the initial auction would reflect two effects that would tend to offset one another. On the one hand, there would be an increase in supply that would push prices down, while, on the other hand, the higher procurement target would tend to push prices up. Thus, the net impact on prices is unclear. A better understanding of the bidding behavior in PJM would be beneficial to better understanding the potential economic consequences. For example, if speculative conduct is a significant factor, it is unclear why sufficient speculative offers do not enter the initial auction to drive down prices to those earned for selling out capacity in the subsequent rebalancing auctions.

[109] If an Installed Capacity Supplier is found to have a shortfall of capacity during a capability period, the NYISO assigns a penalty of one and one-half times the applicable market-clearing price multiplied by the number of MW the Installed Capacity Supplier is deficient. NYISO Installed Capacity Manual, Section 5.8 ICAP Supplier Shortfalls and Deficiency Payments.

[110] See, for example, Bouchez, N. "Fuel Assurance Initiative: Fuel and Performance Incentives Critical Operating Day Incentives", New York Independent System Operator, Market Issues Working Group/ICAP Working Group, December 18, 2014. Available at: http://www.nyiso.com/public/markets_operations/committees/meeting_materials/index.jsp?com=bic_miwg

[111] ISO-NE and New England Power Pool, Filings of Performance Incentives Market Rule Changes, Docket ER14-1050-000, January 17, 2014; FERC, Order on Tariff Filing, Docket ER14-1050-000, Issued May 30, 2014 (147 FERC ¶ 61,172).

[112] PJM, "PJM Capacity Performance Updated Proposal," October 7, 2014.

While having no affect the effectiveness of performance incentives, the choice between a forward or spot capacity market may affect the costs imposed on resources from these incentives depending on the specific provisions of the performance incentive design. To the extent that performance incentives depend on the frequency of shortage events (however defined) and the specific performance of a resource during such events (however measured), resources will face uncertainty about the expected revenues (or costs) faced from such provisions.[113] As a result, uncertainty about such revenue (cost) streams will be greater further from the delivery date because of uncertainty about system and market conditions, and resource capability. As a result, the implications for cost are potentially complex.

f) Regulatory Timing and Flexibility

The switch to a forward market would have implications for the NYISO's and regulators ability to rely on the ICAP market to achieve near-term reliability outcomes. In the current spot market framework, changes to capacity market rules can be implemented immediately. Thus, to the extent that market rule changes are aimed at existing resources, these changes can immediately affect reliability outcomes.[114] By contrast, under a forward market, because there is a three-year lag between the auction and the delivery year, there is a multi-year lag before changes to market rules are able to affect reliability outcomes. As a result, if infrastructure or operational decisions are necessary to address reliability concerns, interim programs would be required to achieve these outcomes, rather than relying on the capacity market.

The development of enhanced performance incentives in ISO-NE and PJM offers an illustration of this issue. In ISO-NE, although the "Pay for Performance" changes to its capacity market were approved by FERC in May of 2014, resources will not be subject to the new rules until the 2018-2019 commitment period.[115] Because ISO-NE faced immediate reliability concerns arising from insufficient fuel assurance during winter months, interim winter programs were implemented to ensure that there is sufficient fuel supply (i.e., supply not at risk to natural gas delivery curtailment) during winter months.[116] These programs were adopted in lieu of efforts to modify existing CSOs that had already been procured in earlier capacity auctions. In contrast, PJM proposes to transition more quickly to its new market design by implementing incremental procurements of the new

[113] Schatzki and Hibbard (2014) discuss these effects in the context of ISONE's Pay for Performance provisions.
[114] Resource changes may not occur immediately due to a number of factors. While market rule changes would immediately affect decisions about new resources, the impact of such decisions would be delayed until these resources are constructed and able to supply output. Also, In some cases, changes in market processes might be required for rule changes to immediately affect outcomes, For example, immediate changes to the demand curve might not occur until the next demand curve reset, which normally occurs every three years, unless special provisions were made for an "off-cycle" reset proceeding.
[115] FERC, Order on Tariff Filing, Docket ER14-1050-000, Issued May 30, 2014 (147 FERC ¶ 61,172).
[116] See, for example, the ISO-NE Winter 2013/2014 Reliability Solutions Key Project, available: http://www.iso-ne.com/committees/key-projects/winter-2013-2014-reliability-solutions

Capacity Performance product for the 2016-2017 and 2017-2018 delivery years.[117] The different approaches taken to addressing interim reliability concerns – with one region undertaking stop- gap procurements and the other transitioning to new requirements – likely reflects a combination of factors, including the extent to which the market designs accommodate a quick transition and the tradeoffs offered by the two approaches.

C. Implications for Economics and Markets

The market design changes under consideration have a number of potential implications for economic outcomes, including the efficient use of resources, the allocation of economic risk and the cost to load. Both the decision to adopt a forward market and the decision to adopt a price lock-in (with a forward market) will affect these economic outcomes.

1. *Efficient Resource Decisions*

Market-based mechanisms can lower the cost of achieving reliability objectives by allowing the market to identify the least-cost means of supply needed resources. To achieve this objective, markets should be designed to allow all comparable resources to compete equally and fairly (at their true opportunity cost) for the opportunity to supply the resources being procured.

a) Implications of a Forward Market

The choice between a spot and forward market has implications for various types of resource's ability to compete in a capacity market:

1. *New Generation Resources*. New generation resources are not able to directly compete in a spot market until investment costs have been sunk at which time the new resource is effectively a price taker. By contrast, new generation resources in a forward market can compete with existing resources before sinking capital into new plant investment. Absent a price lock-in, the clearing price is only guaranteed for the first year of an operating lifetime that will likely span multiple decades.[118] Another factor affecting the economic cost of new entry is associated with the lumpiness of new investment, which we discuss further below.
2. *Existing Resources*. As discussed previously, forward procurement has implications for financial risks. On the positive side, the ability to lock-in a price three years in advance may provide additional revenue certainty. On the negative side, forward procurement limits resource optionality by constraining future action and potentially subjects the resource to deficiency costs or penalties if the resource is unable to deliver contracted supplies. On net,

[117] PJM, "PJM Capacity Performance Updated Proposal," October 7, 2014, pages 33-34.
[118] If capacity prices are serially correlated, then the entrant can reduce the risk of entering at a time when clearing prices are at a low point, which may continue for multiple years.

these effects are expected to be negative, resulting in an increase in going forward costs.

3. *Demand Response*. As discussed previously, forward procurement tends to raise financial risks to demand response providers because providers are generally unable to contract with customers that far in advance (and to the extent that customer contracts extend for that long, they will likely have terms that do not bind the customer to particular load levels).
4. *Imports*. Like existing resources, imports may face additional opportunity costs from forward procurement. When resources are supplied from external resources, these resources limit their flexibility to later decide into which market to supply. However, given that ISO-NE and PJM operate forward markets, the value of the option to delay supply decisions may be relatively low because the only option to supplying into the NYISO spot market is to supply into the ISO-NE and PJM rebalancing markets, to the extent that additional supply is required. Thus, because resources in these neighboring regions already face the costs of operating in forward markets, a switch by the NYISO to a forward market may not impose any incremental costs.

There are two additional issues associated with a switch to a forward market that potentially affect the efficiency of economic decisions: the non-scalability (or "lumpiness) of new resource investment and seasonal variation in resource needs and supplies.

b) New Resource Non-Scalability

New generation resources are "lumpy" – that is, tend to be added in large, discrete chunks, rather than a continuous flow. This lumpiness arises because power plant construction is subject to minimum scale (i.e., new plants have a minimum size) and economies of scale (i.e. larger plants are proportionally less costly on a dollar per MW basis). Because of this lumpiness, new generation plants can be large in proportion to the size of the capacity market into which they enter, particularly for smaller, locally constrained zones, such as Long Island and NYC. For example, an 800 MW combined cycle plant would represent approximately a 13% increase in supply in Long Island and a 8% increase in supply in NYC.[119]

Resource lumpiness can create complications for developing efficient markets that affect both spot and forward market designs. Because new plants reflect a large, discrete quantity of capacity, new resources tend to depress price upon entering the market. When the size of a new resource is large relative to the market, this price effect is potentially large. Consequently, developers must consider how new capacity will affect immediate and future market clearing prices when making decisions about developing new resources.

With a spot market, investment decisions are made before resources enter the capacity market. Because investment costs are sunk, development costs are not included in the resource's initial offers

[119] Based on summer 2014 cleared capacity totals.

when it first enters the capacity market. As a result, new resources are effectively price takers, with prices set based on the most costly existing resources.

Because the new entrant cannot establish an offer price at which it is willing to enter the market, there are circumstances in which it would be efficient for a new resource to enter but the post-entry price would be too low to support recovery of capital costs. Under these circumstances, more costly existing resources may continue to be supported by the market, while less costly new resources will enter only after the supply of capacity becomes sufficiently short to support higher post-entry prices. In addition, estimating post-entry prices is complicated by the lack of information about the bids of existing (infra-marginal) resources.

With a forward market, resources can submit bids at the cost of new entry, which ensures that the market clears at this price (or higher) in the first year of operation. A one year price guarantee may on its own provide little financial value for long-lived assets that recover costs over a 20- to 40-year period. However, because a forward market clears new resources only if the supply is needed to meet demand, there is greater assurance that other resources will not also enter, thus further collapsing the price. In addition, there is assurance that the short-term equilibrium (in the forward market) is consistent with cost of entry. By comparison, under a spot market, there is a three-year lag between the decision to construct the new capacity and market participation, which requires that the capital investment be made based on a three-year ahead forecast of prices.[120] PJM's RPM allows a three-year lock-in of the first year price when certain eligibility criteria at met. These criteria are designed to measure when entry is large in proportion to the market (or zone) in which the entry occurs, thus potentially collapsing the price.[121]

Given resource lumpiness, both ISO-NE and PJM forward markets allow market participants the option to specify for each resource (or block of a resource's offer) a minimum quantity that can clear in the auction.[122] These provisions, referred to as "non- rationing" rules, can avoid the risk that only a portion of a resource's capacity clears the market (i.e., it is "rationed), such that it would be unable to recover its full going forward during the delivery year.[123] For new resources, these

[120] Risk would be mitigated if there is serial correlation in prices, such that a higher first year price tends toward higher prices in subsequent years.

[121] Resources must provide notification that it is seeking the three year lock-in under the New Entry Price Adjustment (NEPA) rules. The bid offer must increase the total UCAP in a LDA from a MW quantity below the reliability target to a MW quantity to a point on the VRR curve that is no greater than 0.4 x net CONE. Further, the resource must be the marginal bid and set the price in the BRA. See PJM "Education and Background, Capacity Senior Task Force" September 13, 2012. Available: http://www.pjm.com/~/media/committees-groups/task-forces/cstf/20120913/20120913-item-02-nepa-background-education.ashx
In 2012, 112.6 MW in DPL South qualified for NEPA in the 2014/2015 BRA. See Monitoring Analytics, "Analysis of the 2014/2015 RPM Base Residual Auction", April 9, 2012.

[122] In PJM, minimum offers are satisfied through Make Whole payments, if needed. PJM, "PJM Capacity Market," Manual 18, pages 85, 95.

[123] In principle, such an option could be included in NYISO's spot market. Without such an option, resources may clear only a portion of its offered capacity, which may not allow it to recover its full going forward cost if this

provisions are particularly important, because new resources offer at the cost of new entry, which may be the market-clearing price. Thus, without such provisions, there is a risk that only a fraction of a new plant clears in the market and the developer is unable to recover the investment costs. The current NYISO Spot Market design requires that all bids be rationed, thus creating the risk that resources may receive payments for only a portion of the unit's capacity.[124] This risk does not necessarily lead to inefficient resource outcomes, although participants may adjust bids to reflect this risk by, for example, increasing offers above going forward costs to ensure that they are able to recover the full going forward costs over the course of the year.

While these "non-rationing" provisions provide market participants with greater assurance that they can recover resource going forward costs, they do introduce complications into auction clearing rules. In ISO-NE and PJM, markets clear to maximize the social surplus, reflecting the difference between demand and supply, in the current auction.[125] Because of non-rationing, market results can include outcomes in which more costly rationed resources clear instead of less costly existing resources and more costly existing resources clear instead of less costly new resources. While aiming to optimize economic outcomes in the current auction, these outcomes could have unintended consequences for subsequent auctions, particularly to the extent that they are unable to account for outcomes in future auctions.

c) Implications of a Price Lock-In

Use of a price lock-in (within a forward market) may lead to greater market-based entry of new generation resources than would occur with a spot market due to a reduction in the cost of finance, enhanced revenue opportunities or other factors. However, use of a price lock-in has several implications for economic outcomes that should be considered. First, a price lock-in for new resources has implications for competition between new and existing resources, and efficient use of capital. Second, a price lock-in can affect incentives for resources to bid strategically, which may result in bids that are above true costs. We elaborate on these potential impacts in further detail below. Third, a price lock-in can also affect the allocation of risk between suppliers and load. Because both supply and load lock-in prices, both parties can hedge future uncertainty in capacity prices.[126] The magnitude of each of these effects varies with the length of the lock-in period.

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outcome were to be sustained. Monthly auctions tend to soften this impact because of month-to-month changes in market outcomes.

[124] NYISO ICAP Manual, Section 5.15.

[125] In ISO-NE, "… the auctioneer shall analyze the aggregate supply curve to determine cleared capacity offers and Capacity Clearing Prices that result in procuring at least the amount of capacity required while seeking to maximize social surplus for the associated Capacity Commitment Period" ISO-NE, Market Rule 1, III.13.2.7.4.

[126] For example, within NYISO markets, load-serving entities enter into bilateral long-term contracts with market participants to supply capacity and other market services. Such contracts hedge risks for both parties. However, each party may value such hedges differently, and each party's demand for hedges may be such that full hedging of risks is not desirable.

(1) Efficient Resource Use

A key objective of competitive market design is creating a market in which supplies from alternative sources can compete on an equal basis. A price lock-in for new resource entry could lead to a bias toward capacity from new resources at the expense of capacity from existing resources. As a result, excessive spending on new resources and premature retirements of existing resources could occur.[127] In the long run, inefficient resource decisions lead to higher consumer costs.

As discussed earlier, a multi-year price lock-in is expected to lower the cost of entry for new generating resources. Because existing resources would not have the option to lock-in prices, a lock-in option for new resources would have no direct effect on existing resource's going forward costs. However, if a lower cost of new entry leads to reduction in capacity market prices, capacity market revenues may no longer be sufficient to support continued operation for some existing resources.[128] To the extent that a price lock-in lowers capacity market prices, some existing resources could retire if the resulting capacity market revenue streams are insufficient to cover going forward costs.[129] Thus, while a multi-year price lock-in may support new resource entry, this support can come at the expense of support for existing resources.

The adverse impact of a price lock-in on prices for existing resources can potentially be mitigated to some degree through market design. For example, in PJM, resources that clear with a three-year price lock-in are required to be offered into the auctions in years two and three at a price equal to the lesser of the year-one offer price and 90 percent of net CONE.[130] As a result, a resource with a lock-in may not clear in the year two- and three-auctions, thus limiting to some degree the potential impact on existing resources prices after the first year.

While not available to all resources, a price lock-in is potentially justified from an economic standpoint for several reasons. First, as discussed in the prior section, new resource "lumpiness" can depress prices when entry occurs, particularly in smaller markets. To avoid this effect, particularly in smaller capacity markets, a limited price lock-in can provide some limited price assurance given the risks that prices collapse upon entry. PJM market rules allow a 3-year price lock-in to address this concern, although it permitted only under limited circumstances that appear to have been seldom

[127] Written Statement of Dr. David B. Patton, Market Monitoring Unit for the New York Independent System Operator. Joint Technical Conference on New York Markets and Infrastructure, Docket No. AD14-18-000, November 5, 2014.
[128] A new entry price lock-in could affect capacity market prices in two ways. First, the price lock-in could lower the market-clearing price in the year in which the new resource enters the market. Second, the price lock-in could lower prices in subsequent years to the extent that entry would not have occurred absent the lock-in.
[129] In PJM, market rules require that new resources that receive a three-year price lock-in bid in capacity into the subsequent two years at the lower of the bid in the initial year or 90 percent of net CONE in the initial year. As a result, the new supply only affects clearing prices in the second and third year when prices are at or above the required offer. PJM Tariff, Attachment DD, § 5.14(c)(4). In ISO-NE, new resources that clear with a price lock-in cannot offer a de-list bid, which effectively makes the resource a price taker. ISO-NE, Market Rule 1, 13.1.1.2.2.4.
[130] PJM, "Manual 18: PJM Capacity Market," Revision 24, July 31, 2014, p. 87.

triggered.[131] Second, in regions that rely heavily on a capacity market to maintain resource adequacy, the adverse impact of a failure to meet resource adequacy targets because new resources do not enter the market may be disproportionately larger than the outcomes if excess new entry is encouraged or the costs awarded to new entrants is too high.[132] Thus, support for new resources might be encouraged to ensure that developers will respond to capacity shortages that emerge because of resource retirements or other factors. Within NYISO, this issue may be less of a concern given the backstop solutions available under the CSPP. Third, if there are external factors, such as real or perceived regulatory risk, that disproportionately impact certain resources (e.g., new resources), then incentives to offset such factors may be warranted.

(2) Strategic Bidding

Within any market design, participants may have many opportunities to use bidding strategies to increase the revenue streams they earn. Such strategic bidding can have a variety of economic consequences, including inefficient use of resources or transfers between different market participants. The adoption of a price lock-in has a number of potential implications for strategic bidding that should be considered given the resulting economic outcomes.

First, resource developers might be able to time entry such that they can lock-in at a price above the resource's cost of new entry or above long-run market prices. Evaluating the likelihood that suppliers will be able to lock-in such a price advantage is complex, requiring dynamic analysis over future periods given many uncertainties and current market conditions. On the one hand, because of resource lumpiness, prices tend to fall after new entry. Thus, prices may actually be at a comparatively low level (and below prices in the prior period) after entry occurs. On the other hand, under tight conditions (when prices are high), if new entry of resources is constrained, prices may remain elevated for prolonged periods.[133] Because resources have the option to decide when to lock-in prices, there is a risk that a new resource enter at a time when clearing prices are unexpectedly (and unsustainably) high, thus allowing the resource to lock-in at an "above market" price. While this circumstance could be viewed as leading to an "unacceptably" high price, absent the lock-in opportunity, the new resource may not have entered and prices could have been even higher.

Second, depending on auction design, resource owners may have incentives to submit resource offers in excess of their true going forward costs.[134] This incentive generally exists within

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[131] New resources may opt not to lock-in at the post-entry price, particularly given that post-entry prices may be lower than future prices because of the increase in supply from the new entry.
[132] Testimony of Robert Ethier, FERC, Docket No. ER14-1639-000, April 1, 2014, page 31.
[133] While typically, it would be unusual to observe prices in excess of the true cost of new entry, in electric power markets, opportunities for entry in particularly locations can be limited to due to many technical, geographic and regulatory factors.
[134] When the bid from the marginal resource affect the clearing price, that resource has an incentive to increase its offer to receive a price in excess of its costs.

capacity market designs, because bids from new resources may set the market-clearing price. A price lock-in option could exacerbate this incentive by increasing the reward to submitting a bid above cost, because this premium would be earned not only in the first year but in all subsequent years in the lock-in period. Absent competition from other bidders, developers of new resources may have the incentive to raise bids until supply – including the new resources – clears demand. Under these circumstances, competition from other resources, including existing and new supply, can reduce the incentives for new resource to submit offers above their true going forward costs because they increase the risk that the bidder does not clear the market.

The risk posed by such strategic bidding depends on several factors. First, there is the probability that an offer is lost because of an above-cost bid. Second, there is the potential magnitude of the over-bidding, which will depend on the gap between the resource's true costs and current prices.[135] While a price lock-in would increase incentives for bids above true costs, the more profitable development opportunity created by the lock-in could also spur greater competition, thus reducing the likelihood that over-stated offers would clear the market.

Concerns about this type of strategic bidding would be greatest in zones when supply does not currently clear demand, such as NYC and Zones G-J. In these cases, the gap between the bids from existing resources and clearing prices is potentially large. In this case, while a new entrant could raise its offer above true costs, new entry would nonetheless lower market clearing prices below prevailing levels before entry.

d) Seasonal Variation in Resource Needs and Supplies

Resource adequacy requirements are generally driven by summer peak loads, although they also reflect transmission topology, resource performance (availability), support from neighboring systems and other factors. Many of these factors, and particularly peak loads, vary across seasons.[136] As a result, resource adequacy requirements are generally driven by loads and resource performance during particular seasonal periods.[137]

The current ICAP capacity market design includes a monthly spot market to procure the installed capacity requirement for each month. Because of certain differences in resource

[135] More precisely, this gap will depend on the resource's true costs and the vertical intercept between offered supply and the demand curve.

[136] Peak loads vary due to weather conditions, work schedules and other factors and the potential supply from many resources varies with seasons due to a variety of factors, including environmental regulations, the efficiency of thermal systems (e.g., given ambient air and cooling water intake temperature), and resource availability (e.g., for hydro, wind and solar resources).

[137] New York State Reliability Council, "New York Control Area Installed Capacity Requirement for the Period May 2014 to April 2015," Technical Study Report, December 6, 2013; NYISO, "2014 Load & Capacity Data Report," April 2014.

performance, the supply and demand for capacity varies between summer and winter months.[138] Several differences in supply are in effect. Many internal NYISO resources can supply greater capacity during winter months because lower ambient temperatures increase operating efficiency.[139] Partially offsetting this increase in capacity is a reduction in import capacity supplied by HQ. Because these changes have resulted in an increase in net capacity, capacity prices have tended to be lower in winter than summer months.

With a shift to a forward market, operation of a monthly forward market would likely be impractical. Moreover, a monthly forward market would seem inconsistent with the nature of the service being procured, which is capacity to meet annual, not monthly, peak loads. Thus, the operation of a monthly capacity market is not necessary to the procurement of capacity resources.

Because a forward market would likely involve a switch to an annual capacity market, the NYISO would need to consider the particular circumstances under which resources currently supply capacity into the NYISO monthly market, and the increased costs that may result from moving to an annual commitment. In particular, at present, capacity from HQ varies by season, with higher levels of supply in summer months and lower levels of supply in winter months, when HQ capacity is needed to meet winter-peaking loads in Quebec. Under the current ISO-NE FCM rules, resources are only able to offer supplies that are deliverable across the entire year. However, to account for seasonal variation in resource supplies (and potentially other factors), resources are permitted to submit "composite" offers in which the eligible capacity reflects the combined capability of the separate resources.[140] Thus, supply offered into ISO-NE from resources with varying seasonal capability (such as HQ with higher summer capability, and thermal units with higher winter capability) can match to take advantage of their negatively correlated supplies. Thus, operation of a forward market can be compatible with seasonal variation in resource supplies given appropriate market rules.

Operation of monthly spot auctions provides other potential benefits, including more frequent price discovery and potentially greater liquidity. With more frequent auctions, price discovery occurs more frequently and markets are able to adjust to changes in resource conditions more quickly than with an annual auction.

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[138] Because of differences in the Derating Factor between summer and winter months, the ICAP requirement differs between summer and winter months. For example, in 2013, the UCAP requirement differed by 543 MW between summer and winter months. Potomac Economics, 2014, page A-155.
[139] Potomac Economics, 2014, page A-154.
[140] ISO-NE, Market Rule 1, III.13.1.5, Offers Composed of Separate Resources.

2. Reliance on Regulated Solutions

As described in earlier in Section IV.B, a forward market may reduce the duration of a RSSA when such an agreement is required to address reliability concerns arising from a resource retirement. When these agreements require that resources offer supply into the capacity market as price takers, they can lower prices below levels that would have prevailed had the resources been permitted to exit the market. Such reduction in prices can distort prices and reduce incentives for new resources to enter the market (including new resources needed to replace the resource on the RSSA seeking retirement), or for existing resources to continue supplying capacity. A forward market, particularly with a price lock-in, may also reduce the likelihood that other out of market solutions are developed by encouraging greater market-based entry, although such entry may result in other costs associated with a price lock-in, as described above.

With a spot market, unanticipated retirement of resources may provide the NYISO and PSC with limited time to develop solutions to mitigate any reliability needs that emerge as a consequence of the retirement. To the extent that the limited time available to develop reliability solutions reduces the available solutions or leads to negotiated RSSA terms that are less favorable to load (in terms of either price or agreement duration), a forward market potentially mitigates such risks by allowing more time to deliberately develop alternative reliability solutions.

3. Risk Allocation

The shift from a spot market to a forward market would involve the reallocation of certain financial risks associated with capacity markets. We focus on three issues: resource availability, price volatility and variability in payments.

a) Resource Availability

One important risk relates to resource availability. Under the current spot market, suppliers do not face any cost if a resource experiences a significant loss of capacity due to a forced outage, aside from the loss of capacity revenues. However, because a forward market includes a commitment to deliver capacity, suppliers are exposed to greater financial risk associated with a significant loss of capacity between forward market clearing and the delivery period, and during the delivery period. These costs reflect the obligation to replace any lost capacity, and penalties if such replacement is unavailable. Because of differences in the nature of these commitments, deficiency penalty mechanisms may be more stringent under a forward market, as compared to a spot market.

As a consequence of this shift in risk, this creates an additional (or greater) cost in forward market offers as compared to spot market offers. However, this allocation of risk can improve resource availability because resource suppliers are in the best position to take steps to ensure that resources do not experience significant forced outages. Consequently, this allocation of risk is potential efficiency improving.

b) *Price Volatility*

The adoption of a forward market may have consequences for price volatility. From the standpoint of suppliers, less volatile prices would reduce financial risk, which can lower the costs for new and existing resources.

In principle, a forward market will tend to provide less volatile prices than a spot market because a forward market clears based on *expected* quantities that tend to be less volatile than quantities needed at the time of delivery, given plant outages, increases in demand and other unanticipated “shocks”.[141]

However, there are other differences between a forward market and NYISO’s current market that may also affect price volatility. For example, the current NYISO ICAP market is monthly, while a forward market would clear annually. In addition, differences in the way in which new resources participate in the market could also affect volatility.

c) *Variability of Payments*

Variability of payments by load (and revenues to generators) reflects a combination of factors, including price volatility (as discussed above) and the forward lock-in of supplies. A forward market provides the opportunity to lock-in a large fraction of transacted supplies at expected market levels (three years in advance), while adjusting to the actual supply needed through a series of subsequent rebalancing auctions. The impact on costs to load – both in terms of the level of payments and variability in payments – depends importantly on the quality of the initial forecast of needed supplies.

In principle, the initial forward auction could either over- or under-procure compared to final requirements that would be procured in the spot market. When insufficient capacity is procured, rebalancing auctions procure additional supply needed to meet requirements. In this case, procurement costs may be lower in the forward market than the spot market because, while both markets procure the same quantity of resources, the forward market is likely to initially clear at a lower price because less supply is procured.[142] By contrast, when the excess capacity is procured, rebalancing auctions must identify suppliers willing to sell back obligations. If suppliers are willing to sell back obligations, the total cost to load would be diminished and the level of capacity procured would be consistent with demand. If suppliers are unwilling to sell back obligations, then excess supply would be purchased.

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[141] This is the same relationship that exists between day-ahead and real-time energy markets.

[142] Under both a spot and forward market, the supply of resources to meet a higher-than-expected load could be relatively tight under this scenario. In either case, new entry decisions (as well as other resource decisions) will similar expectations in both a spot market and a forward market. While prices in a forward market may too low to support new entry, in a spot market, expectations of clearing prices three years ahead also would not support new entry.

To the extent that supplier decisions to physically participate in a region's wholesale markets are unlikely to change as the delivery date nears, then, in practice, few suppliers may be willing to sell back capacity.[143] In this case, the risk associated with forward procurement may not be completely symmetric, but would impose an additional cost on load.[144]

Our quantitative modeling considers these two cases in scenarios that reflect particular market conditions.[145] Our modeling results illustrate several important findings. First, with the forward market, *the variation in cost to load (and payments to suppliers) is narrower than it is under a spot market*. This effect is illustrated by Figure 29, which shows the impact of a 5 percent increase and decrease in the load forecast on the cost of load under a spot market, and a forward market with and without a price lock-in. In this scenario, we assume an "accurate" forecast, with an equal likelihood that the actual quantity is above and below the forecast quantity. With the spot market, the cost to load is $8,098 million and $4,479 million with a 5 percent increase and 5 percent decrease in load, respectively. This wide range in cost to load arises because the 10 percent swing in load results in a significant difference in clearing prices, as well as a difference in quantity procured.

By contrast, with the forward market, the cost to load is $6,755 million and $6,529 million with a 5 percent increase and 5 percent decrease in load, respectively.[146] With the forward market, the initial purchased quantity is the same in both cases, with the difference in cost to load arising because of the differences in the adjustments made to the final capacity requirements through the rebalancing auctions. When final load is higher, only the additional capacity is procured at the higher prices. In contrast, when the final load is lower, only a portion of the load initially purchased is sold back at the lower price. Thus, the forward market cost to load is relatively unchanged by the change in demand, while the spot market cost to load changes by nearly a factor of two.

This comparison potentially exaggerates the differences in variation to cost to load for several reasons. First, the NYISO's spot market operates on a monthly, not an annual basis. Monthly auctions will tend to reduce variability in cost to load by averaging out "shocks" to supply or load. Second, load serving entities in New York may not purchase all supplies needed to fulfill their capacity obligations through the ICAP spot market. Instead, LSE's can using various contractual arrangements to spread out procurement cost risks, such as multi- year bi-lateral contracts and participation in the NYISO's annual strip auctions.

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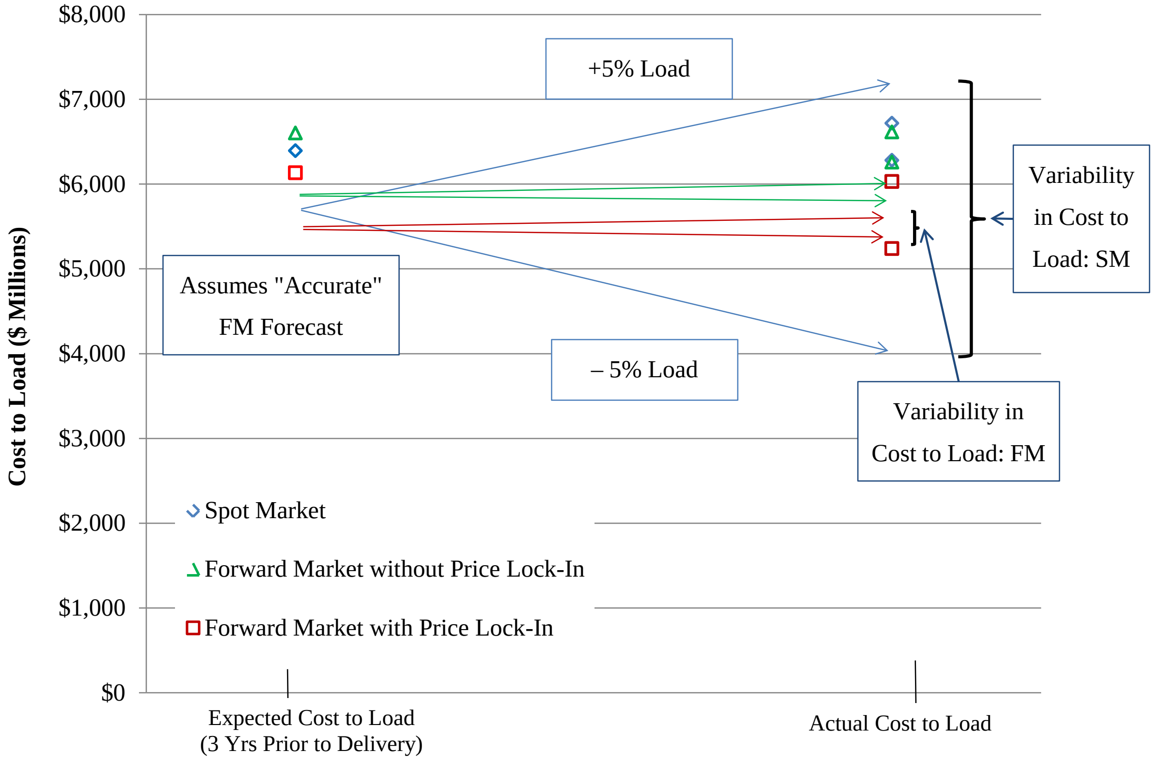
[143] Or, the price they are willing to accept to give up their commitment could be unacceptably low.
144 As discussed earlier in Section IV.B.1, in PJM, the significant churn of resources after the initial auction suggests some willingness by resources to sell back commitments.
[145] Our analysis also reflects certain modeling assumptions. In particular, we assume that the higher forward market supply costs prevail in subsequent rebalancing auctions used to procure additional supply or sell-back obligations even though supply costs may diminish as the time between the forward rebalancing auction and the delivery period becomes shorter.
[146] Numbers reported for the situation without a price lock-in. With a price lock-in, the total cost to load is $6,307 million and $6,066 million for a 5 percent increase/decrease in load, respectively.

Figure 29: Cost to Load with Uncertain Load:
Spot and Forward Market Outcomes differ relative to no change in load forecast



Second, the analysis also shows *the expected impact to the cost-to-load associated the risk of over- and under-procurement is not necessarily equal (or symmetric)*. In fact, these outcomes depend on the slopes of the supply and demand curves, with neither over- nor under-procurement necessarily leading to higher costs. Under the scenarios we evaluate, reflecting the NYISO supply and demand curves, over- procurement leads to higher costs than under-procurement. Thus, the risk associated with load uncertainty leads to an expected loss to load (assuming that over- and under-procurement is equally likely). Assuming that an increase and decrease in load are equally likely, the expected cost to load under a forward market with no lock-in is $6,642 million while the expected cost to load under a spot market is $6,288 million.[147] Thus, there is a $353 million or 5.6 percent increase in expected cost with the forward market. When a price lock-in is included, the expected cost to load is $6,186 million. With the lock-in, the difference in cost to load is only $102 million less, or 1.6 percent of the expected spot market cost.

Third, *the difference in cost to load in each of the over- and under-procurement scenarios is significantly greater than in other scenarios evaluated*. For example, the cost to load under forward markets when load is 5 percent lower than expected is $1,588 million and $2,050 greater than costs under a spot market with and without a lock-in, respectively. When the likelihood of over- and

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[147] For the forward market with a lock-in, this reflects a cost to load of $6,187 million.

under-procurement are (roughly) equal, these two impacts offset one another, resulting in a smaller expected impact on average, such as those represented in Figure 29.

However, if the forecast of procurement quantities is systematically biased toward over- or under-procurement, then the implications for costs could be significant. In particular, the high cost of over-procurement is important in the context of previous concerns raised that, given the uncertainty over setting procurement targets three years in advance, that market operators may tend to over-procure in the initial auction relative to a true forecast of need.[148] If such a bias is present, it suggests that over-procurement comes at a potentially high cost relative that may not be commensurate with the improved reliability gained given any concerns about procuring additional capacity in subsequent rebalancing auctions that may be driving the tendency toward conservative forecasts.

4. Cost to Load

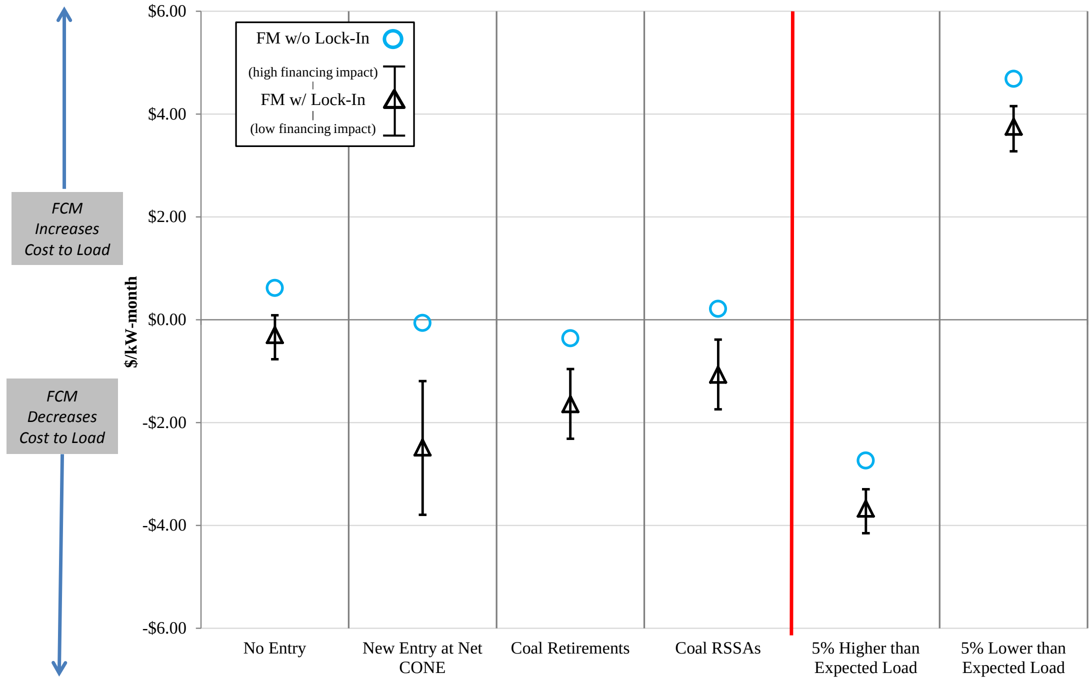
The quantitative modeling provides several general lessons for the impact of a forward market for the cost to load. However, when evaluating these results, it is important to remember that these provide a static representation of the capacity market, i.e., a one year snapshot based on the expected supply and load forecast conditions in 2020. Certain dynamic factors are unaccounted for, such as the potential for uplift from new resource multi-year price lock-in.

First, the shift to a forward market could either increase or decrease the cost to load depending on circumstances. The net impact reflects two important effects. To the extent that a forward market imposes additional opportunity costs on existing resources, the switch to a forward market raises costs. Offsetting this increase in costs, the lower cost of new entry would tend to lower market clearing costs, both by reducing market clearing costs when the market clears at new entry and by shifting the supply curve down.

Second, because of these effects, a forward market with or without a price lock-in, tends toward reduced supply of capacity, although there are circumstances in which the clearing quantity remains unchanged. Because the supply of resources is not constant across scenarios, the average cost of capacity across scenarios provides a useful way of comparing scenarios by controlling for such differences. Figure 30 provides estimates of the average cost per MW. On this average cost metric, costs increase slightly with a forward market (up to about \$0.50 per kW-month) and decrease when a price lock-in is added (with decreases up to about \$2.50 per kW-month).

[148] To the extent that models used to establish resource adequacy targets include forecast variance as an input, blind application of current procedures for establishing resource adequacy targets to a forward market could lead to systematic bias toward over-procurement because forecast variance is greater three years prior to delivery as compared to one month prior to delivery. Such a bias could be offset by simply assuming the forecast variance for the time period of the last rebalancing auction when establishing the resource adequacy for the first auction, because the final quantity of capacity procured will reflect this smaller forecast variance, not the larger three-years-ahead forecast variance.

Figure 30: Change in Total Cost to Load, All New York Consumers, $/kW-mo ($2020)



When considering potential decreases in cost to load as a consequence of a price lock-in, it is important to consider potentially offsetting effects not captured. First, to the extent that price lock-in leads to new entry, this may also increase the frequency at which the market clears at new entry offers, instead of lower offers from existing resources. Second, with a price lock-in, there is a risk that the lock-in is used only when the developer anticipates that expected prices will be less than the offer price. While uplift payments may raise the cost to load associated with a price lock-in, our quantitative analysis suggests that such uplift is likely small in proportion to overall capacity costs (see Section III.E). Because new resources will continue to be a small fraction of the overall fleet, these incremental payments will tend to be relatively small in comparison to payments to the overall fleet.

D. Administrative and Institutional Factors

A key issue to consider in evaluating the potential benefits and costs of a FM structure is the ultimate cost to NYISO (a) to initially make the change, involving a commitment of expenses and human resources over an extended period, as well as capital outlays; and (b) to annually administer the new FM structure, compared to the annual and capital costs to administer the current SM structure. Evaluating these potential costs is complicated by the degree to which system software is linked across all markets, considerations related to the approach NYISO would take in moving from a SM to FM structure from a system hardware and software design perspective, and a general level of uncertainty related to the ultimate time and resources needed to process design changes in house, through a stakeholder process, and ultimately before FERC.

In order to develop a sense of the potential magnitude of startup costs, and annual differences, we consulted with representatives from the New England and PJM regions that had been involved in initial development of their forward capacity market structures, and that are familiar with the efforts involved in administering the current FM structures. In addition, we discussed with NYISO staff their current personnel and systems dedicated to SM administration, and what the expectations would be for transitioning to a FM structure. Specifically, we explored with the representatives from all regions the following areas of inquiry:

- Which departments or divisions are involved in planning for, designing, administering and operating the FM structure, and what are their responsibilities. Specific divisions or areas of responsibility discussed included Market Development, Market Administration, Planning, Legal, Information Systems, Market Monitoring, Operations, Financial, and Corporate/Executive.
- Estimate of the costs to initially design, process (in stakeholder and regulatory settings), and develop the FM structure, including personnel involved (by department), outlays for designing IT systems and software, and any other capital investment.
- Estimate of the current cost to administer the FM structure in each year, including how many Full Time Equivalents ("FTE") are in each department with time devoted to FM structure activities, how that work breaks down by activity (for example, setting requirements and qualifying resources; associated system studies; market administration/operation; regulatory filings; billing/settlement; IT services), and whether there are specific divisions responsible for specific FM-related activities or sectors (e.g., demand response)?
- How the region tracks/allocate expenses related to FM structure activities, particularly where they are only one piece of a shared resource (e.g., market administration, market design, planning, regulatory).
- The approach, design, and processes necessary to deal with the FM structure from an IT perspective, in particular, including the IT and software used to operate the FM structure, initial and ongoing cap capital outlays, and current expected life of operations; the annual operating expense for running and maintaining the FM structure tracking/administration, and how that may be identified separately from other market and administrative activities.

Generally, ISONE and PJM's experience was dominated by the stakeholder, regulatory, and IT efforts involved in developing recommended market structures (in their case, generally from scratch with little precedent around the country at that time), processing them with stakeholders, following through on regulatory filings, installing hardware and developing the software to run the auction and market settlement systems, and testing/implementation.

Based on our discussions, we come to the following observations related to administrative burdens:

- The time for transition from the current system would likely take at least 3 years. The other regions took up to five years from design to administration, with the actual timing somewhat subjective based on stakeholder lead-up processes. Managing the stakeholder process was a far more time- and resource-intensive process than expected in both regions. Staff from across nearly all departments would be needed in the design and stakeholder processes.

- The move to a FM structure would likely require the building of IT systems from a clean slate in NY, since the current SM structure would not be adequate for adaptation or use in a FM structure. Based on discussions with the other regions, this would likely run into the tens of millions of dollars for in-house or vendor development. Incremental updates would be on the order of a few million dollars per year.

- Different departments would likely have different resource needs under a FM structure. In both ISO-NE and PJM the process and implementation did not require significant new hires, but there was a fair amount of reassignment of staff internally. Current FTE staffing to administer the FM structures in ISO-NE and PJM is between 10 and 20 FTEs, with a fair amount of external vendor support as well. In New York's case, it is expected that there would need to be on the order of 10 or more new hires across departments, and possibly some reassignments, to administer a FM structure.

- It was suggested that building the design be done in-house and with sufficient lead time in order to have the flexibility to control the timing of updates and scheduling.

In consideration of the above findings, it appears that the move to a FM structure in New York would be costly and resource intensive, but manageable with sufficient lead time. Based on a review of the major software changes and design, stakeholder and regulatory experiences in moving to FM structures in ISO-NE and PJM, it is reasonable to expect that moving to a FM structure in New York would (a) require a full reworking of market software, (b) involve an up-front expense of on the order of a couple to a few tens of millions of dollars, and (c) require substantial commitment of existing staff time for market design, administration through the shared governance process, regulatory approvals, and initial implementation. On the other hand, the annual administration of a FM structure would likely not require a major change in resource requirements relative to the administration of the current SM structure, but would likely require the re-purposing of existing staff to different areas. Finally, the experience in other regions suggests moving software design in-house, and a minimum of three years for proper processing and implementation of a new FM structure.

V. APPENDICES

A. Appendix I: Model Inputs

This appendix describes the data, assumptions, and methodology used to estimate clearing prices and quantities, based on the current spot market capacity auction structure.[149] A detailed description of the modeling scenarios and differences between a forward and spot market is covered in Section III of the body of the report. The individual elements for the model covered here include demand curve assumptions and parameters; supply curve assumptions and parameters; and auction clearing rules.

The model includes the current four capacity zones (New York Control Area "NYCA", Lower Hudson Valley "G-J", New York City "NYC", and Long Island "LI"), and the estimated clearing price is based on the intersection of the administratively set demand curve for each locality and the estimated supply curve.[150] The model includes a nested structure, such that generators receive the highest clearing price in their overlapping zones. Similarly, unit bids clear in a nested fashion; units that clear in the NYC auction are included as price taking units in the G-J auction.

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[149] The NYISO currently operates three capacity market auctions: Capability Period ("Strip") auctions, conducted at least 30 days prior to the capability period, with resource bids for the same MW level and price for the entire period; Monthly auctions, conducted at least fifteen days prior to the start of the month, for any month remaining in the capability period; and the Spot auction, which is conducted 2-4 days prior to the start of each month. In the Spot auction, the NYISO procures all capacity bids that clear the administratively set demand curve.
[150] See NYISO ICAP annual, Section 5.15.

1. Demand Curve

Demand curves are estimated using the current 2014 Gold Book load forecast, the summer 2014 and winter 2014/2015 ICAP/UCAP translation factors, current Installed Reserve Margin ("IRM") and Locational Capacity Requirement ("LCR") factors, and the recently approved reference prices for each locality (see Figure A1.1).

The slope of each demand curve is defined by three points. First, for each demand curve, the reference price is set at the point equal to 100 percent of the capacity requirement. Second, the length of each demand curve is defined by the zero crossing point, equal to 118 percent of the reserve requirement in NYC and LI, 115 percent in G-J, and 112 percent in NYCA. Third, the demand curve maximum clearing price is defined as 150 percent of gross CONE for each locality.

Reference prices were developed through the demand curve reset process, in consultation with stakeholders and based on the modeling work of the Brattle Group and NERA.[151] The reference price is set to the net CONE for an F-class frame with SCR (zones G-J, NYC, and LI) and an F-class frame without SCR in NYCA, escalated annually at 2.2 percent inflation (Table A1.1). Net CONE includes expected energy and ancillary services revenues minus fixed and variable operating costs, including taxes, depreciation, and financing costs.[152]

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[151] For a detailed description, see New York Independent System Operator Proposed Tariff Revision and Demand Curve Reset Filing, Submitted November 27, 2013 to Federal Energy Regulatory Commission, Docket No. ER14-000, and associated materials, available http://www.nyiso.com/public/markets_operations/market_data/icap/index.jsp

[152] As described in the body of the report, as part of this review, Analysis Group updated the financing assumptions embedded in the Brattle/NERA model and calculated additional reference prices for forward capacity market demand curves that account for a potential impact of a 7-year lock-in for new entry.

Table A1.1: ICAP Based Reference Prices

Year	NYCA	NYC	Long Island	G-J Locality
2014	$8.84	$18.55	$7.96	$12.14
2015	$9.03	$18.95	$8.12	$12.41
2016	$9.23	$19.37	$8.30	$12.68
2017	$9.43	$19.80	$8.48	$12.96
2018	$9.64	$20.23	$8.67	$13.24
2019	$9.85	$20.68	$8.86	$13.54
2020	$10.07	$21.13	$9.05	$13.83
2021	$10.29	$21.60	$9.25	$14.14
2022	$10.52	$22.07	$9.46	$14.45

Source:

[1] NYISO 2014-2017 Demand Curve Parameters and Demand Curves, available at: http://www.nyiso.com/public/markets_operations/market_data/icap/index.jsp

The reserve requirement is defined to meet a loss a load of expectation ("LOLE") of one day in ten years (0.1 events per year), defined as:

$$Reserve\ Requirement = Peak\ Demand * \left(1 - \frac{ICAP}{UCAP} translation\ factor\right) * IRM\ (or\ LCR)$$

Where peak demand is based on coincident summer peaks for NYCA and non-coincident peak demand in G-J, J, and K, as defined in the 2014 Gold Book and IRM/LCR factors defined by the NYISO and the New York State Reliability Council (Table A1.2). Installed Capacity values are translated to Unforced Capacity (UCAP) requirements using the summer 2014 and winter 2014/15 ICAP/UCAP translation factors (Table A1.3).

Table A1.2: NYISO Summer Load Forecasts, 2014-2024

	Peak Demand by Zone				Required Installed Reserve Margin	Locational Minimum Requirement		
Year	**G-J Locality**	**NYCA**	**NYC**	**Long Island**	**NYCA**	**NYC**	**Long Island**	**G-J Locality**
2014	16,291	33,666	11,783	5,496	117.0%	85.0%	107.0%	88.0%
2015	16,557	34,066	12,050	5,543	117.0%	85.0%	107.0%	88.0%
2016	16,749	34,412	12,215	5,588	117.0%	85.0%	107.0%	88.0%
2017	16,935	34,766	12,385	5,629	117.0%	85.0%	107.0%	88.0%
2018	17,149	35,111	12,570	5,668	117.0%	85.0%	107.0%	88.0%
2019	17,311	35,454	12,700	5,708	117.0%	85.0%	107.0%	88.0%
2020	17,421	35,656	12,790	5,748	117.0%	85.0%	107.0%	88.0%
2021	17,554	35,890	12,900	5,789	117.0%	85.0%	107.0%	88.0%
2022	17,694	36,127	12,990	5,831	117.0%	85.0%	107.0%	88.0%
2023	17,828	36,369	13,100	5,879	117.0%	85.0%	107.0%	88.0%
2024	17,935	36,580	13,185	5,923	117.0%	85.0%	107.0%	88.0%

Notes:
[1] NYCA represents coincident peak demand, while G-J, NYC, and Long Island represent non-coincident peak demand.

Sources:
[1] 2014 Gold Book, Tables I-2a, I-2b-1, and I-2b-2.
[2] 2014 IRM Report
[3] 2014-2015 Draft LCR Report

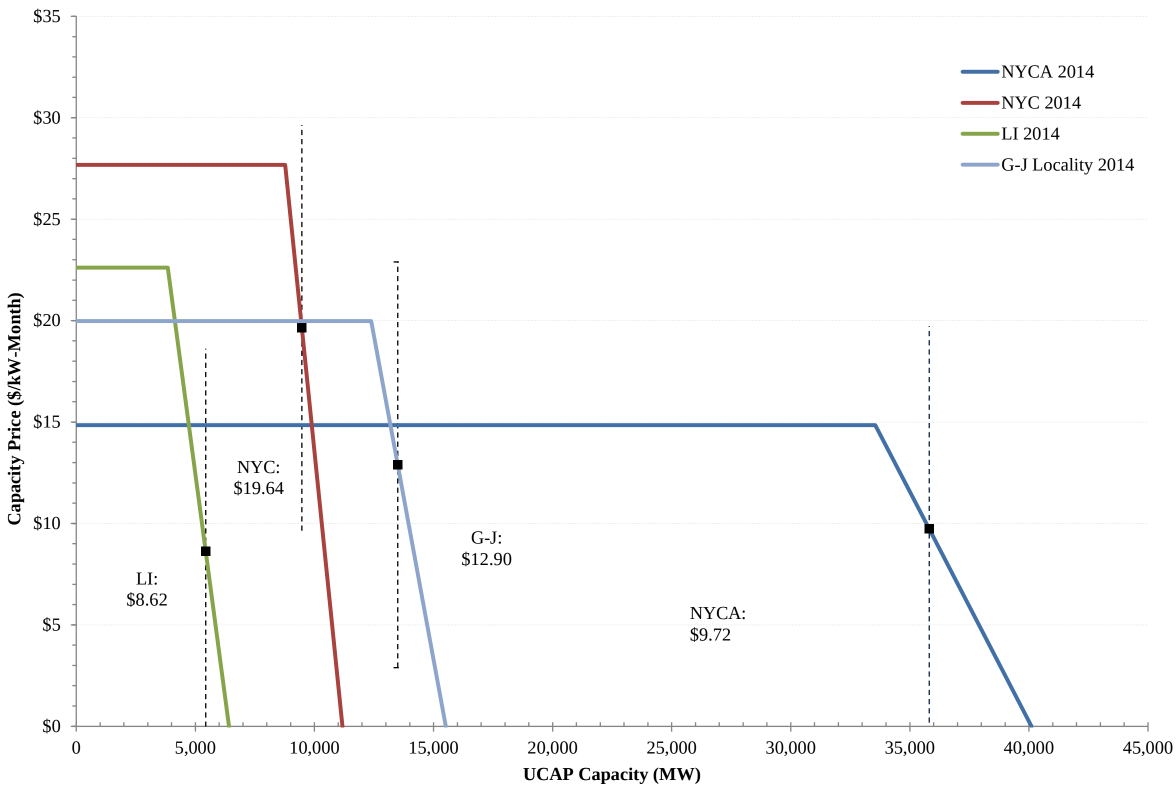
Table A1.3: ICAP/UCAP Translation Factors

	Summer	Winter
NYC	5.44%	5.06%
Long Island	7.65%	8.28%
NYCA	9.08%	7.32%
G-J Locality	5.87%	5.26%

Source:

[1] ICAP/UCAP Translation of Demand Curve, available http://www.nyiso.com/public/markets_operations/market_data/icap/index.jsp

Figure A1.1: Representative Demand Curve (Summer 2014), Expressed in UCAP



Notes:
[1] Reference prices express in UCAP, based on summer 2014 ICAP/UCAP translation factors.
[2] Crossing points do not necessarily reflect the nested nature of clearing prices.

2. Supply Curve

The supply curve and individual bid unit estimates are developed from the 2014 Preliminary CARIS II Base Case, which is used by the NYISO as part of its long-term reliability planning process.[153] As part of this effort, the NYISO provided Analysis Group with the GE MAPS production simulation results, which include annual estimates of energy production and energy market revenues, including ancillary service payments for daily uplift, and total variable operating costs, including fuel expenses, emission costs, and start-up costs for generation units. Notable assumptions in the CARIS 2 Base Case that impact the 2020 modeling period include[154]:

1. Transmission Owner Transmission Solution ("TOTS") projects in-service 2016;
2. Cayuga 1 &2 and Selkirk 1&2 are both retained throughout the study period;
3. Market Based Solutions from the 2012 CSPP included in-service, modeled as 500 MW in-service in 2018 and 2023, respectively at Astoria;
4. Generic gas turbines of 210 MW installed at Barrett Station in 2016 for resource adequacy assurance.

As described above, the production simulation results are combined with additional information to calculate unit specific bids as:

$$Offer = \frac{(FOM + VOM + T + I + E + NRC) - EAS}{UCAP * 12}$$

Where:

- EAS equals Energy and Ancillary Services Revenue, including daily uplift;
- FOM equals Fixed Operations and Maintenance expenses;
- VOM equals total Variable Operating and Maintenance expenses, including variable operating costs, fuel, emissions, and start-up costs;
- T equals annual property taxes;
- I equals annual capital expenditures for investments;
- E equals unit specific estimates of potential environmental retrofit expenses for select generators.
- NRC equals unit specific estimates of potential retrofit expenses for select nuclear generators.

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[153] The 2014 Preliminary CARIS 2 Base Case results were presented to stakeholders at the June 30, July 24, and August 7, 2014 Electric System Planning Working Group meetings and the August 13, 2014 Business Issues Committee.

[154] See Duffy, T. 2014 Preliminary CARIS 2 Base Case Results, Presented to Electric System Planning Working Group, June 30, 2014. Available: http://www.nyiso.com/public/markets_operations/committees/meeting_materials/index.jsp?com=bic_espwg

These values form the starting point for the current evaluation and are used as the basis of the supply curve in both the spot and forward market evaluations. As discussed in Section III, we adjusted the forward market supply curve from this starting point to account for expected changes in existing generator costs due to a three-year forward commitment.

Data inputs for unforced capacity (UCAP), fixed operations and maintenance (FOM), taxes (T), annual investments (I) and environmental retrofits (E) are described below. UCAP generation totals were combined with capacity obligations for external capacity rights, Special Case Resources ("SCRs"), and Unforced Delivery Rights ("UDRs"). These assumptions are described following data inputs.

Unforced Capacity

As part of this project, the NYISO provided unit-specific summer and winter derate factors for existing generators. This data was merged to the summer and winter ICAP values provided as part of the production simulation to convert individual units to UCAP terms. Generic units, and units without available data, were assigned NERC class average EFORd values for resources of the same type, consistent with Section 4.5 of the NYISO Installed Capacity Manual. Similarly, derate values for wind and solar were calculated according to system averages specified in the NYISO ICAP Manual.

Fixed Operations and Maintenance (FOM)

As part of this project, the NYISO provided FOM estimates on a technology and region basis. These values were developed using USEPA IPM model inputs, which in turn are based on FERC Form 1 reports for regulated entities. The NYISO adjusted these values on an as needed basis using information from historical Sargent and Lundy Going Forward Cost Studies, which are developed as part of the annual Installed Capacity Demand Curve filed with the Federal Energy Regulatory Commission. These studies evaluate offering behavior in the context of a broader withholding analysis.

Analysis Group reviewed these FOM estimates and compared them to other publicly available data sources, including class specific estimates from SNL Financial. Analysis Group confirmed that the NYISO values are reasonable based on current expectations. FOM estimates are inflated annually using the Energy Information Administration ("EIA") Annual Energy Outlook Wholesale Price Index for Fuel and Power.

Taxes

Property taxes in New York are among the highest in the nation and represent an important cost to New York generators. Analysis Group estimated property taxes for NYC and the broader zones based on a review of publicly available information, including Payment in Lieu of Taxes ("PILOT") agreements, unit specific assessment data for generators throughout the NYCA region based on conversations with local assessment offices and review of publicly available assessment rolls, and aggregate assessment values for utility property (Class 4 commercial property) in New York City.[155] These data sources were used to develop an imputed $/MW tax value that was assigned to all generating units, based on location.

Investments

The NYISO currently allows generators to include up to six years of historical and projected capital expenses, including but not limited to mandatory expenditures to comply with federal or state environmental, safety, or reliability requirements.[156] These costs are annualized, using the standard annuity formula, with the lifetime (n) defined as the minimum of the periodicity of the expense and the maximum of six and 40 – age of the plant. As a conservative estimate, Analysis Group annualized all investment costs over six years, using an after-tax weighted average cost of capital of 6.37 percent.[157] Analysis Group estimated annual investment costs for capital expenditures based on a review of gross capital expenditure data from reported FERC Form 1 data. Average annual investment costs were estimated as the difference in gross capital expenditures between consecutive years, for the period 2009 to 2013.[158] Average investment costs on a $/kW basis were calculated as the weighted average by capacity for reporting utilities.

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[155] As noted in the demand curve reset filing (NERA/S&L Report, at page 49), power plant equipment that is not rate regulated by the New York Public Service Commission is treated as general commercial property. In 2014, the effective tax rate for Class 4 property was 4.64 percent based on a 10.323 percent tax rate for the 13/14 Fiscal Year and a 45 percent assessment ratio. See New York City Finance Department, available: http://www.nyc.gov/html/dof/html/property/property.shtml.

[156] See, for example, NYISO Installed Capacity Market Going Forward Costs Input Template Instructions: Data Submission Template for Going Forward Cost and Physical Withholding Review, available at: http://www.nyiso.com/public/markets_operations/services/market_monitoring/index.jsp

[157] This is the after-tax weighted average cost of capital, used in the demand curve reset filing. See NERA/S&L, at page 56.

[158] Notably, this method does not account for depreciation and therefore tends to underestimate investments over time.

Table A1.4: Estimated Annualized Capital Expenditures, $/kW-month By Tech and Fuel Type

Technology	*Fuel*	*Number of Plants*	*Cumulative Capacity (MW)*	*Cumulative Capital Investment ($mil)*	*Annualized Capital Investment, $/kW-month*
			[1]	*[2]*	*[3] = annualized [2] * 1000 / ([1] * 12)*
Combined Cycle	Gas	99	70,830	$2,603	$0.59
Combined Cycle	Other Nonrenewable	2	351	$18	$0.80
Gas Turbine	Oil	76	8,359	$36	$0.07
Gas Turbine	Gas	214	52,956	$710	$0.22
Gas Turbine	Biomass	2	14	$1	$0.62
Hydraulic Turbine	Water	445	16,690	$818	$0.79
Pumped Storage	Water	13	11,652	$260	$0.36
Internal Combustion	Oil	95	579	$6	$0.16
Internal Combustion	Gas	7	457	$21	$0.75
Internal Combustion	Biomass	13	51	$4	$1.34
Nuclear	Nuclear	29	49,089	$4,335	$1.42
Steam Turbine	Coal	192	187,172	$9,541	$0.82
Steam Turbine	Biomass	14	672	$57	$1.37
Steam Turbine	Gas	57	29,663	$298	$0.16
Steam Turbine	Oil	9	8,052	$239	$0.48

Notes:

[1] Annual Capital Investment is calculated from gross capital expenditures, as reported in FERC Form 1. Gross expenditures include the total cost of plant (land and land rights), structures and improvements, equipment costs, and asset retirement costs. Annual investment is calculated as the difference in annual gross capital expenditures. Values are converted into $/kW-Month assuming annual operating capacity (MW), as reported by SNL Financial.

[2] Data include power plant units in all regions, and includes a mix of regulated and merchant/unregulated plants

[3] NYISO allows units to include up to 6 years of historical and forecast capital expenditures, annualized using an annuity formula, where n is calculated as the minimum of the periodicity of the expense or equipment replacement and the maximum of 6 years and 40 less the age of the plant. Annual costs are annualized using the standard annuity formula ([i*(1+i)n / (1+i)n- 1]), using a 6 year period and 6.73% after tax weighted average cost of capital discount rate.

[4] NYISO Going Forward Costs includes mandatory capital expenditures necessary to comply with federal or state environmental,

Source:

[1] FERC Form 1, as reported by SNL Financial.

Environmental Compliance Costs

As described above, current NYISO rules allow generators to include mandatory expenditures to comply with federal or state environmental, safety, or reliability requirements in the calculation of going-forward costs. The 2014 Resource Needs Assessment ("RNA") identified ten regulations that could impact as much as 33,200 (88 percent of 2014 summer capacity).[159] Analysis Group included environmental retrofit cost estimates for units that are the most likely to be effected, including the majority of coal units, all nuclear units, and the oldest oil and gas units. Compliance cost estimates were based on Analysis Group's review of similar environmental impacts in other regions and based on consultation with the NYISO. In addition, nuclear units also require retrofits to comply with the Nuclear Regulatory Commission ("NRC") order orders focused on mitigation strategies, containment venting systems, and spent fuel pool instrumentation that were approved in March 2012 in response to the Fukushima disaster in 2011.[160] In particular, mitigation strategies and spent fuel pool instrumentation were required for all U.S. nuclear reactors, while venting system updates were required at all units with a Fukushima-style containment design, GE Electric Boiling Water Reactor Mark I or Mark II reactor. The NRC also requested additional reevaluations of earthquake and flood risk against current design standards and requested evaluations of existing plant conditions.

Recent reports have estimated the average compliance cost for all units to be between $30 and $40 million, with up to 65 percent of estimated costs due to FLEX spending.[161] Similarly, additional cost estimates for containment venting system upgrades to boiling water units with Mark I or Mark II reactors were recently issued at $2 million per unit.[162] For the purposes of this study,

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[159] See Section 5, "Impact of Environmental Regulations", 2014 Reliability Needs Assessment, at pages 46 – 55. These regulations include: NOx Reasonable Available Control Technology ("NOx RACT"), Best Available Retrofit Technology for regional haze ("BART"), Mercury and Air Toxics Standard for hazardous air pollutants ("MATS"), Mercury Reduction Program for coal-fired electric utility steam generating units ("MRP"), Cross State Air Pollution Rule ("CSAPR") and Clean Air Interstate Rule ("CAIR"), Regional Greenhouse Gas Initiative ("RGGI") Phase II cap reductions, CO2 Emission Standards for new sources, New Source Performance Standards and Maximum Achievable Control Technology for Reciprocating Internal Combustion Engines ("RICE"), and Best Technology Available ("BTA") for cooling water intake structures.

[160] Collectively, these are referred to as 'Tier 1 Activities' and were formally addressed by NRC orders 12-049, 12-050, and 12-051 respectively. Task Force recommendations also included information requests and reevaluations of plant upgrades for seismic events and flooding hazards.

[161] A 2013 Platts article surveyed 10 operators with 53 total units, of a US total 102 units, and found an average compliance estimate of $35 million per unit. This included an equal mix of boiling water and pressurized water reactors. See Platts, 2013. "US Nuclear Plant Operators estimate $3.6 bil in post-Fukushima Costs." available at: http://www.platts.com/latest-news/electric-power/washington/us-nuclear-plant-operators-estimate-36-bil-in-21124657; The $30-$40 estimate and 65 percent FLEX proportion comes from a review of Dominion Energy's six unit, three station fleet. See Dalrymple, W. 2013. "Half way – a review of post Fukushima actions in the Americas. Nuclear Engineering International." Available at: http://www.neimagazine.com/features/featurehalf-way---a-review-of-post-fukushima-actions-in-the-americas/.

[162] In a recent order, the NRC moderated its position requiring reliable hardened vents and issued staff to develop

Analysis Group estimated incremental NRC Fukushima compliance costs for the four nuclear generators, Indian Point, James Fitzpatrick, Ginna, and Nine Mile Point using publicly available data from Entergy and Exelon annual reports.[163] Of the New York nuclear units, both James A. Fitzpatrick and Nine Mile Point utilize Mark I or Mark II venting systems. Therefore, an additional $2 million cost was added to the estimated unit compliance cost for containment venting system upgrades. These estimates increase expected capital costs for Indian Point by $94 million, Nine Mile Point by $46 million, Fitzpatrick by $40 million, and Ginna by $14 million. Consistent with other investment costs, these estimates were annualized over a six year period assuming a 6.37 percent discount rate.

a) Additional Capacity Market UCAP Assumptions

The current model also includes additional capacity as price taking units in each zone. This capacity includes external obligations, Special Case Resources ("SCRs") and Unforced Delivery Rights ("UDRs"). Values for SCRs and external obligations were set to summer 2014 averages and winter 2013/2014 averages, defined by zone. Expectations for long run UDRs were provided by the NYISO. Consistent with the CARIS study, these values were held constant throughout the study period, with 2020 forecast levels equal to the averages described above.[164]

A qualitative discussion of the potential impact and likely participation of these resources under a forward capacity market relative to a spot market is included in the body of this report. Special Case Resources ("SCRs") are defined as "demand side resources whose load is capable of being interrupted at the direction of the NYISO, and/or demand side resources that have a local generator… that can be operated to reduce Load…".[165] New SCRs can only participate in the spot auction, unless it is enrolled with a Responsible Interface Party ("RIP") accepted by the NYISO. Within the spot auction, the RIP specifies the minimum payment nomination that the SCR will be paid in the event that it is called upon. Minimum Payment Nominations cannot exceed $500/MWh and serves as a strike price to prioritize which resources to call during a shortage event.[166] In 2013,

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guidance for upgrades or replacements to currently installed vents; the Commission relied, in part, on the finding that new hardened vents could cost on average $15 million per unit and outweigh economic benefits, while updates could be installed at an average cost of $2 million per unit. See "Commission Decision on Additional Requirements for Containment Venting Systems (SRM-SECY-12-0157), March 19, 2013" and "Consideration of Additional Requirements for Containment Venting Systems (SECY-12-0157), November 26, 2012", both available at: http://www.nrc.gov/reactors/operating/ops-experience/japan-dashboard/hardened-vents.html.

[163] Entergy reported a total cost of $200 million for its wholesale commodity fleet, excluding Vermont Yankee (2013 Q3 Financial Update, at 20) while Exelon reported total capital and operating expenses for Fukushima updates at $400 million for its nuclear fleet. For each NY unit, the estimated compliance cost was calculated as Total Fleet Cost * (Unit MW / Total Fleet MW).

[164] See, for example, Table 4-2: CARIS I Base Case Load and Resource Table, 2013 Congestion Assessment and Resource Integration Study, November 19, 2013.

[165] NYISO Installed Capacity Manual, Section 4.12

[166] NYISO Installed Capacity Manual, Section 4.12.3

the Market Monitor found that SCRs accounted for between 2.5 and 3.6 percent of the total UCAP requirement in LI and NYC, respectively.[167] Unforced Capacity Deliverability Rights ("UDRS") are rights, measured in MWs, associated with controllable transmission projects that provide an interface to a locality. UDRs that are combined with unforced capacity located outside of the locality can be used to meet local capacity obligations.[168] In 2014, UDRs available to bid include Cross Sound Cable (330 MW, New England to Long Island), Neptune Cable (660 MW, PJM to Long Island), Linden VFT (315 MW, PJM to New York City), and Hudson Transmission Project ("HTP", 660 MW, PJM to New York City).[169] Similarly, general external capacity provided as imports from PJM, ISO-NE, and Ontario can be used to satisfy UCAP requirements in the NYCA.[170]

b) Forward Market Supply Curve Assumptions

Section 3.2 describes the modeling assumptions used in the forward capacity market supply curve. The following tables provide additional information and support for the probability of a significant derate. This analysis is used to benchmark the deficiency risk.

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[167] Patton, D.B., Lee Van Schaick, P., and J. Chen. 2013 State of the Market Report for the New York ISO Markets. May 2014, at page A-162.

[168] Services Tariff, Section 2.21, at 59, and Section 4.9 at page 4-47.

[169] NYISO Installed Capacity Manual, Attachment B.

[170] Services Tariff, Section 4.9.6. In 2014-15, external capacity imports are capped at 1,080 MW from PJM, 300 MW from ISO-NE, and 1110 MW from Quebec via Chateauguay. Quebec is a winter peaking system, and grandfathered MW transactions are limited to 1090 MW April-November and 239' MW December – March.

Table A1.5: Summary of Significant Derates of Generator Units, Excluding Forced Outage Retirements 2010-2014, All Units Greater than 25 MW

Unit	Tech Type	Fuel Type	Capacity	Derate	Derated MWs as a % of Total MW
Oswego 5	ST	FO6	839.7	-54.2	-6%
Roseton 2	ST	FO6	607.5	-42.5	-7%
Bowline 2	ST	NG	551.1	-371.4	-67%
Hellgate 1	GT	NG	46.0	-4.5	-10%
Gowanus 6	GT	NG	45.1	-4.8	-11%
Hellgate 2	GT	NG	44.7	-4.8	-11%
Ravenswood 3-1	JE	NG	38.7	-5.9	-15%
Ravenswood 2-1	JE	NG	37.8	-5.7	-15%
Ravenswood 2-2	JE	NG	37.0	-3.6	-10%
Ravenswood 3-2	JE	NG	36.9	-4.8	-13%
Stewarts Bridge	HY	WAT	34.3	-4.4	-13%

Source:

[1] NYISO Goldbooks, years 2010 - 2014.

Note:

[1] Derates are defined as Summer Capacity decreases greater than or equal to 40 MW or a percent decrease in capacity of greater than 10%.

[2] Capacity is the maximum Summer Capacity for each unit over the 2010 to 2014 period.

Table A1.6: Generator Retirements, 2009 - 2014

Unit	Operator	Zone	Fuel Type	Summer Capacity (MW)	Effective Year	Retirement
Greenidge 3	AES Eastern Energy, LP	C	Fuel Oil	52.2	2009	
Westover 7	AES Eastern Energy, LP	C	Fuel Oil	40.2	2009	
Energy Systems North East	AES Eastern Energy, LP	A	Natural Gas	79.4	2010	
Project Orange 1	AES Eastern Energy, LP	C	Natural Gas	40.0	2010	
Project Orange 2	Erie Blvd. Hydro - Lower Hudson	C	Natural Gas	0.0	2010	
Poletti	New York Power Authority	J	Fuel Oil	890.0	2010	
Greenidge 4	AES Eastern Energy, LP	C	Bituminous Coal	106.1	2011	
Westover 8	AES Eastern Energy, LP	C	Bituminous Coal	81.2	2011	
Ravenswood GT 3-4	TC Ravenswood, LLC	J	Kerosene	31.7	2011	*Forced Outage*
Barrett 07	Long Island Power Authority	K	Natural Gas	18.0	2011	*Forced Outage*
Dunkirk 3	NRG Power Marketing LLC	A	Bituminous Coal	185.0	2012	
Dunkirk 4	NRG Power Marketing LLC	A	Bituminous Coal	185.0	2012	
Beebee GT	Rochester Gas and Electric Corp.	B	Fuel Oil	15.3	2012	*Forced Outage*
Binghamton Cogen	Standard Binghamton LLC	C	Natural Gas	41.3	2012	
Astoria 2	Astoria Generating Company L.P.	J	Fuel Oil	182.8	2012	
Astoria 4	Astoria Generating Company L.P.	J	Fuel Oil	381.2	2012	
Astoria GT 10	NRG Power Marketing LLC	J	Natural Gas	17.5	2012	
Astoria GT 11	NRG Power Marketing LLC	J	Natural Gas	16.4	2012	
Glenwood ST 04	Long Island Power Authority	K	Natural Gas	115.0	2012	
Glenwood ST 05	Long Island Power Authority	K	Natural Gas	108.7	2012	
Far Rockaway ST 04	Long Island Power Authority	K	Fuel Oil	106.7	2012	
Dunkirk 1	NRG Power Marketing LLC	A	Bituminous Coal	75.0	2013	
Syracuse Energy ST1	Syracuse Energy Corporation	C	Bituminous Coal	11.0	2013	
Syracuse Energy ST2	Syracuse Energy Corporation	C	Bituminous Coal	63.9	2013	
Chateaugay Power	ReEnergy Chateaugay LLC	D	Biomass	18.2	2013	*Forced Outage*
Danskammer 1	Dynegy Danskammer, LLC	G	Fuel Oil	61.0	2013	*Forced Outage*
Danskammer 2	Dynegy Danskammer, LLC	G	Fuel Oil	59.2	2013	*Forced Outage*
Danskammer 3	Dynegy Danskammer, LLC	G	Bituminous Coal	137.7	2013	*Forced Outage*
Danskammer 4	Dynegy Danskammer, LLC	G	Bituminous Coal	237.0	2013	*Forced Outage*
Danskammer 5	Dynegy Danskammer, LLC	G	Fuel Oil	0.0	2013	*Forced Outage*
Danskammer 6	Dynegy Danskammer, LLC	G	Fuel Oil	0.0	2013	*Forced Outage*
Montauk Units #2, #3, #4	Long Island Power Authority	K	Fuel Oil	5.7	2013	
Freeport 1-1	Freeport Electric	K	Natural Gas	1.5	2013	
Station 9	Rochester Gas and Electric Corp.	B	Natural Gas	14.3	2014	*Forced Outage*
Ravenswood 07	TC Ravenswood, LLC	J	Kerosene	12.7	2014	*Forced Outage*
Total				**3,391**		
Total Returned to Service				**1,047**		

Notes:

[1] Retirements does not include Proposed or Scheduled Retirements, including units currently on Reliability Support Service Agreements. Excludes Hydro units and select units with reported zero MW summer capacity.

[2] Units that have or did request a returned to service or will be repowered are highlighted in blue. These units may return to service at capacities other than reported retirement capacities.

[3] Forced Outage retirements are units that indicated a forced outage or other equipment failure as the cause of retirement in their notification to NYISO.

Sources:

[1] 2008-2014 NYISO Gold Books, Table IV-3 Units Removed from Existing Capacity.

[2] NYISO Planned Generation Retirements.

3. Auction Clearing Rules and Mechanism

The NYISO Installed Capacity Manual specifies the market clearing rules for each of the three NYISO capacity market auctions. The spot market clearing price is determined by the intersection of the supply curve of total unforced capacity and the ICAP demand curve for each locality.[171] The lowest cost combination of bids is selected, subject to the constraint that local capacity obligations are first met. This means that auctions are nested in each capacity zone, such that capacity that clears in Zone J also clears in G-J and in NYCA.

The current model allows for a partially selected offer of a given bid for both new and existing generation. In contrast, in a forward market, an important design consideration is the stipulation for bid rationing rules. If allowed, certain bid offers may choose to be non-rationable, and instead require that the full quantity of capacity be selected. In these situations, bid rationing rules would suggest that the operator as one of two choices – to either procure extra capacity (the full extent of the bid) at the market clearing price, or to exclude the non-rationable bid and potentially select a the next available, potentially higher cost resource that satisfies the reserve requirements.

Two examples illustrate the market clearing rules used in the current model. In example 1, Bid C intersects the demand curve. The auction clearing price is set at the bid price (here, generically $2/kW-mo), but the clearing capacity is calculated at the intersection of the demand curve. In essence, the hypothetical 4 unit capacity of Bid C is partially selected as 2.7 units. These units are included in the nested zones, with the remaining 1.3 units of Generator C available to bid in at a price of $2/kW-mo.

[171] NYISO Installed Capacity Manual, Section 5.15.

B. Appendix II: Project Finance Details

Table A2.1: Summary of Cost of Financing Research for Recent Natural Gas Power Plants, Project Details

#	Plant	Tech	Capacity (MW)	Developer	ISO	State	Year (Financing)[1]	Year (In-Service)	Interest Rate Terms
1	Linden Cogeneration	CT	948	East Coast Power	NYISO	NJ	2013	1992	LIBOR+2.75% w/1% LIBOR floor
2	Bayonne Energy Center	CT	512	ArcLight Energy (50%)/Hess Corporation (50%)	NYISO	NJ	2014	2012	LIBOR+3.5% w/1% LIBOR floor
3	Astoria Generating Co.	*Refinancing (1,732 MW total)*		Astoria Generating Co.	NYISO	NY	2012	-	LIBOR+5.5-6% w/1.25% LIBOR floor
4	Garrison Energy Center	CC	309	Calpine	PJM	DE	2013	2015	LIBOR+2.5-3%
5	CPV St. Charles	CC	725	Marubeni Corp (50%), Competitive Power Ventures (25%), Toyota Tsusho (25%)	PJM	MD	2014	2016	LIBOR+3.5%
6	CPV Woodbridge	CC	700	ArcLight Energy (50%), Toyota Tsusho (31.25%), Competitive Power Ventures (18.75%)	PJM	NJ	2013	2016	LIBOR + 4.25%
7	Liberty Power	CC	936	Panda Power Funds	PJM	PA	2014	2016	LIBOR+6-6.5%
8	Patriot Power	CC	829	Panda Power Funds	PJM	PA	2014	2016	LIBOR+6-6.25%
9	Walnut Creek Energy Park	CT	495	NRG Energy	CAISO	CA	2011	2013	LIBOR+2.25% rising over time for $442m LIBOR+4% for $53m LIBOR+2.44% weighted average
10	Mariposa Peaker Project	CT	200	Diamond Generating Corp	CAISO	CA	2012	2012	LIBOR+2% rising over 10 years
11	Los Esteros Critical CC Plant	CC	306	Calpine	CAISO	CA	2011	2013	LIBOR+2.25%
12	CPV Sentinel Energy Project	CT	800	Competitive Power Ventures (25%), DCG (50%), GE (25%)	CAISO	CA	2011	2013	LIBOR+2.25%
13	Marsh Landing Generating Station	CT	788	NRG Energy	CAISO	CA	2010	2013	LIBOR+2.75-3%
14	ExGen Texas Power Projects	*Refinancing of 5 plants (3,500MW total)*		Exelon	ERCOT	TX	2014	-	LIBOR+4-4.25% w/1% LIBOR floor
15	Antelope-Elk Energy Center	CT	190	Golden Spread Electric Coop	ERCOT	TX	2013	2016	2.74-5.75% Senior Secured Notes
16	Panda Temple II Facility	CC	758	Panda Power Funds	ERCOT	TX	2013	2015	6.00% fixed
17	Panda Sherman Generating Statior	CC	650	Panda Power Funds	ERCOT	TX	2012	2014	LIBOR+8% w/1.5% LIBOR floor
18	New Covert	CC	1,233	Tenaska	MISO	MI	2014	2003	LIBOR+4.5-4.75% w/1% LIBOR floor
19	Saguaro Power Company	CC	105	NRG (50%), MSD Capital (25%), Paragon Energy Holdings (25%)	Other	NV	2014	1991	LIBOR+2.90%

Notes:
[1] Year of financing represents the year that a deal closed, or if unavailable, the year that relevant financing information was reported.
[2] LIBOR is assumed at 20 bps to calculate bps above LIBOR for fixed-rate issuances.

Sources:
[1] Project Finance International.
[2] Company specific 10-K financials.
[3] News articles.
[4] SNL Financial.

Table A2.2: Summary of Cost of Financing Research for Recent Natural Gas Power Plants, Contract Details

#	Plant	Max bps above LIBOR	PPA Agreed at Time of Financing?	PPA/Bilateral Details	Notes
1	Linden Cogeneration	275	Yes, with Utility	25 Year PPA with ConEd through 2017.	Refinancing. Provides energy into NYISO through the Linden VFT UDR.
2	Bayonne Energy Center	350	Tolling Agreement with Merchant Retailer	Tolling agreement with Direct Energy (62.5%) and ArcLight (37.5%)	Refinancing. Delivers power through dedicated 7 mile submarine cable from NJ to NYC.
3	Astoria Generating Co.	600	-		Refinancing, due to FERC determination on Buyer Side Mitigation for Astoria Energy II, including cost of financing assumptions
4	Garrison Energy Center	300	No		
5	CPV St. Charles	350	No		
6	CPV Woodbridge	425	No	"Expected to sell its capacity through 15-year Standard Offer Capacity Agreements (SOCAs) with New Jersey utilities, and energy through a hedge," but no specific PPAs mentioned; also agreed 16-year Contractual Services Agreement with GE for maintenance.	
7	Liberty Power	650	No		Originally developed by Moxie, acquired by Panda Power during development
8	Patriot Power	625	No		Originally developed by Moxie, acquired by Panda Power during development
9	Walnut Creek Energy Park	244	Yes, with Utility	10 Year PPA with Southern California Edison through 2023.	
10	Mariposa Peaker Project	200	Yes, with Utility	10 Year PPA with PG&E through 2022.	
11	Los Esteros Critical CC Plant	225	Yes, with Utility	10 Year PPA with PG&E through 2023.	
12	CPV Sentinel Energy Project	225	Yes, with Utility	10 Year PPA with Southern California Edison for 5 of 8 units through 2023.	
13	Marsh Landing Generating Station	300	Yes, with Utility	10 Year PPA with PG&E through 2023.	
14	ExGen Texas Power Projects	425	No		Refinancing of portfolio of 5 CC, ST, and CT assets
15	Antelope-Elk Energy Center	575	No		
16	Panda Temple II Facility	600	No		
17	Panda Sherman Generating Statior	800	No		Includes a financial hedge with a different plant north of Dallas.
18	New Covert	475	No		Refinancing.
19	Saguaro Power Company	290	Yes, with Utility	30 year PPA with Nevada Power through 2022.	Refinancing.

C. Appendix III: Model Scenarios

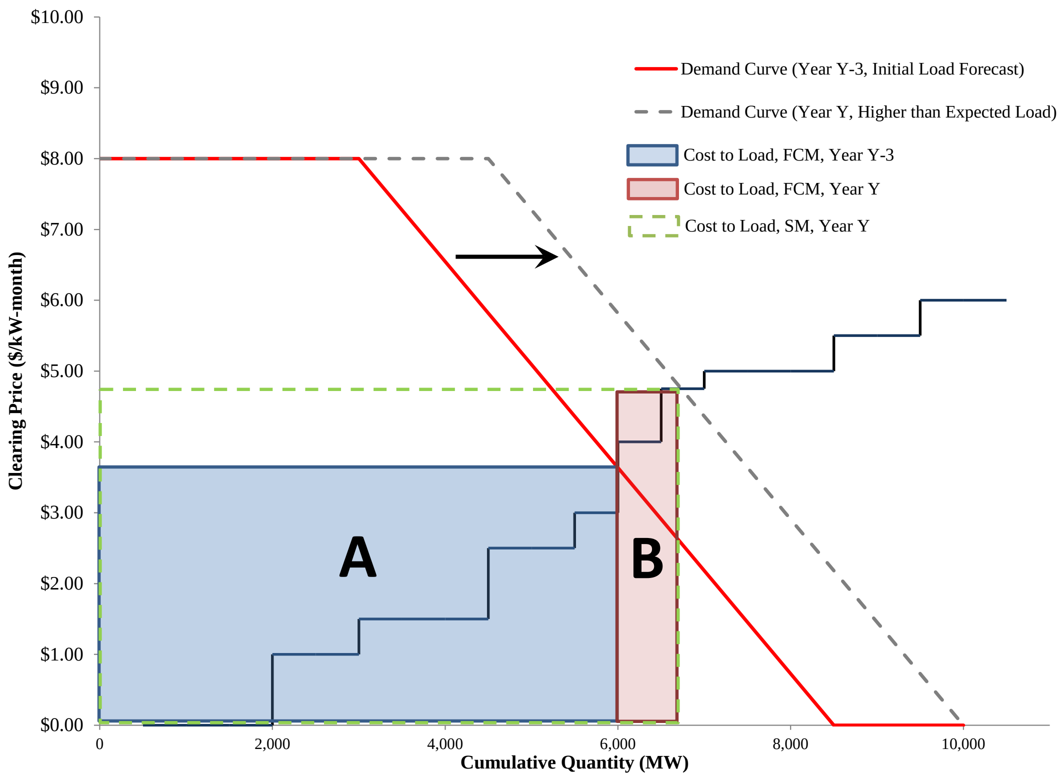
This appendix provides additional details on individual scenario results and calculations, as necessary.

Higher and Lower than Expected Load Scenarios

In the Higher than Expected Load scenario, the actual load used to set the final demand curve in year 2020 is five percent higher than the 2014 Gold Book forecast values. In the forward market, the first procurement auction at Y-3 (here, 2017) procures capacity to meet the 2020 forecast target. The clearing price and the total cost to load for this quantity is represented by the blue shaded box A in Figure A3.5. In year Y (here, 2020), the total forecast increases by five percent. In the reconfiguration auction, the forward market must procure the quantity of capacity equal to the red shaded box B in Figure A3.5. Here, we have assumed that the sufficient capacity exists in the existing supply curve. In practice, the supply curve may include additional quantities of resources with shorter development lead times, including additional imports, capacity from UDRs, or higher than expected SCRs. The cost to load for this new quantity of supply is equal to the new clearing price, calculated at the intersection of the existing supply and (new) demand curve. The total cost to load for the forward market is equal to shaded box A + shaded box B.

In contrast, the spot market procures the capacity in year Y for the higher than expected load forecast. Here, the total cost to load is equal to the green dashed box. All capacity receives the ultimate clearing price at the higher than expected demand curve.

Figure A3.1: Illustrative Cost to Load Calculation
Higher than Expected Load Forecast



In the lower than expected load scenario, the forward market inititally clears at the 2020 forecast. The clearing price and total cleared quantity is equal to the sum of shaded boxes A+B+C in Figure A3.6.

In year Y, the actual forecast is five percent lower than the forecasted quantity based on the 2014 Gold Book values. In this instance, we assume that existing capacity sells out of its obligation at a price equal to the new intersection of the demand curve and existing supply curve. The shaded box B represents payments made by generators or other entities to procure this reconfiguration capacity. This may occur if resources face a deficiency in their own obligations. The loss to consumers is equal to the shaded box C, which represents the difference between the costs originally paid to capacity at year Y-3 and the revenues generated in the reconfiguration at year Y. Therefore, in the lower than expected load forecast scenario, the total cost to load in the forward market is the sum of shaded box A + shaded box C.[172]

In contrast, the total cost to load in the spot market is equal to the green dashed box that represents the intersection of the updated demand cuve and the existing supply curve.

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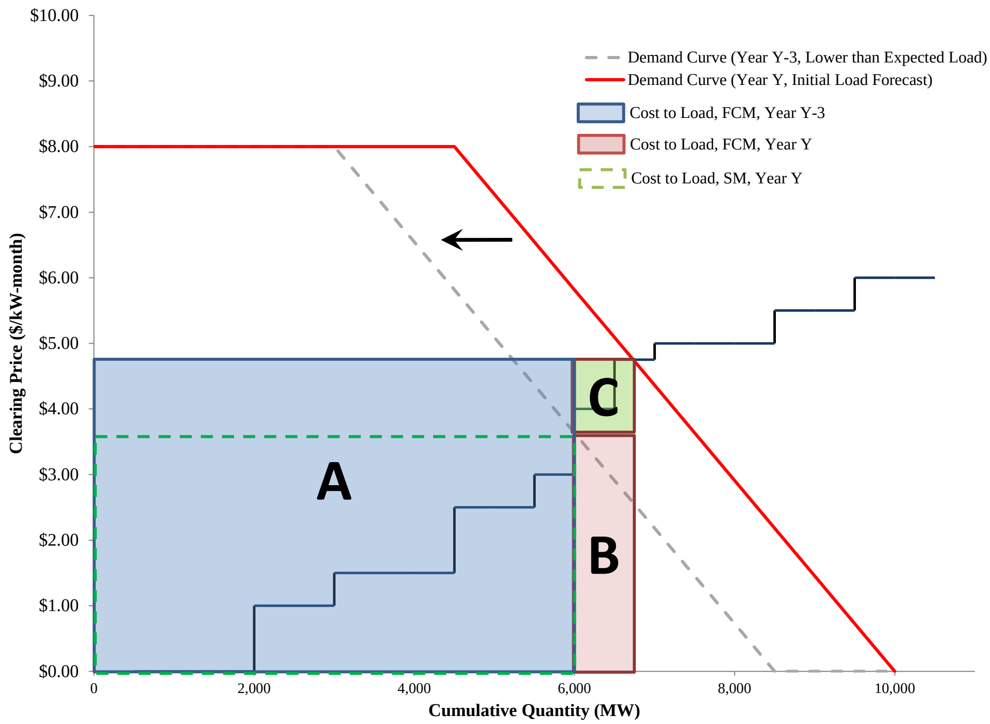
[172] Note that the worst-case scenario would assume zero capacity in the reconfiguration auction, with the total cost to load in year Y equal to the original commitment made in year Y-3, calculated as the sum of A+B+C.

**Figure A3.2: Illustrative Cost to Load Calculation
Lower than Expected Load Forecast**



In practice, the relative cost of the load forecast error depends on the slope of the supply and demand curve. In Long Island, the supply curve is relatively flat. Clearing prices for a reconfiguration auction in year Y are more similar to clearing prices in year Y-3. This minimizes the size of C (above) and reduces the impact of a load misspecification, illustrated with the solid grey box, for payments made to the remaining capacity. On the other hand, the supply curve in NYCA (ROS) is steep, with increasing marginal cost bids for additional capacity. In this region, a reconfiguration auction or load misspecification has a greater cost to load. It raises the clearing price paid to all generators that do not sell out in the reconfiguration auction (grey box) and also increases the deadweight loss from a potential reconfiguration (green box).

Figure A3.3: Lower than Expected Load Forecast, Long Island
Comparison of FM Auction at Y-3 and Y

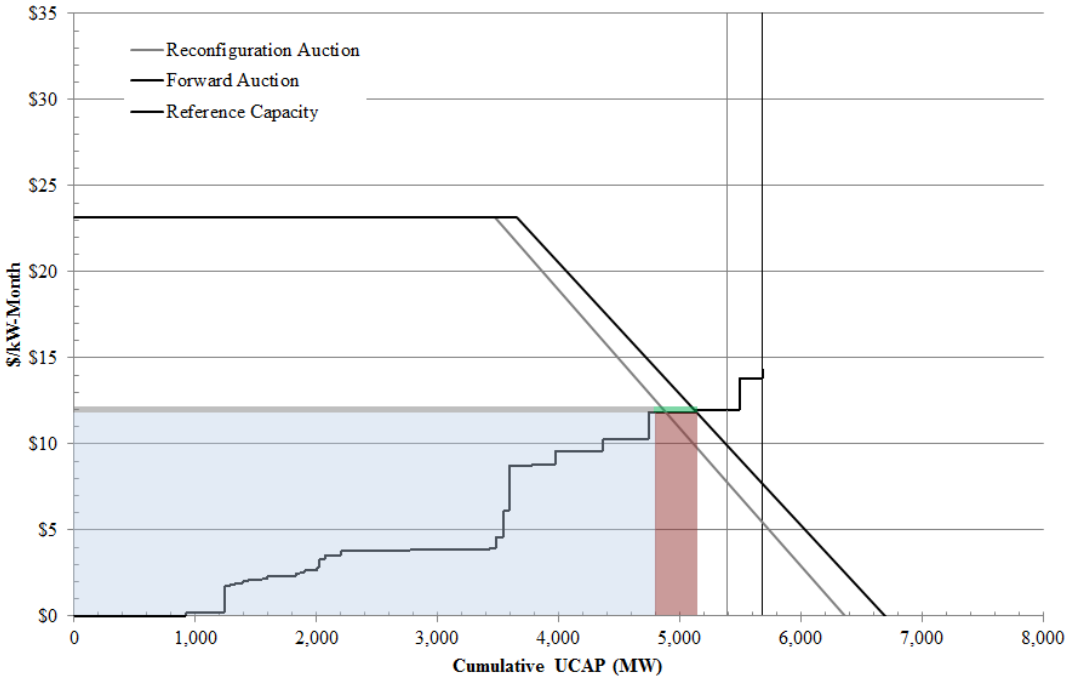
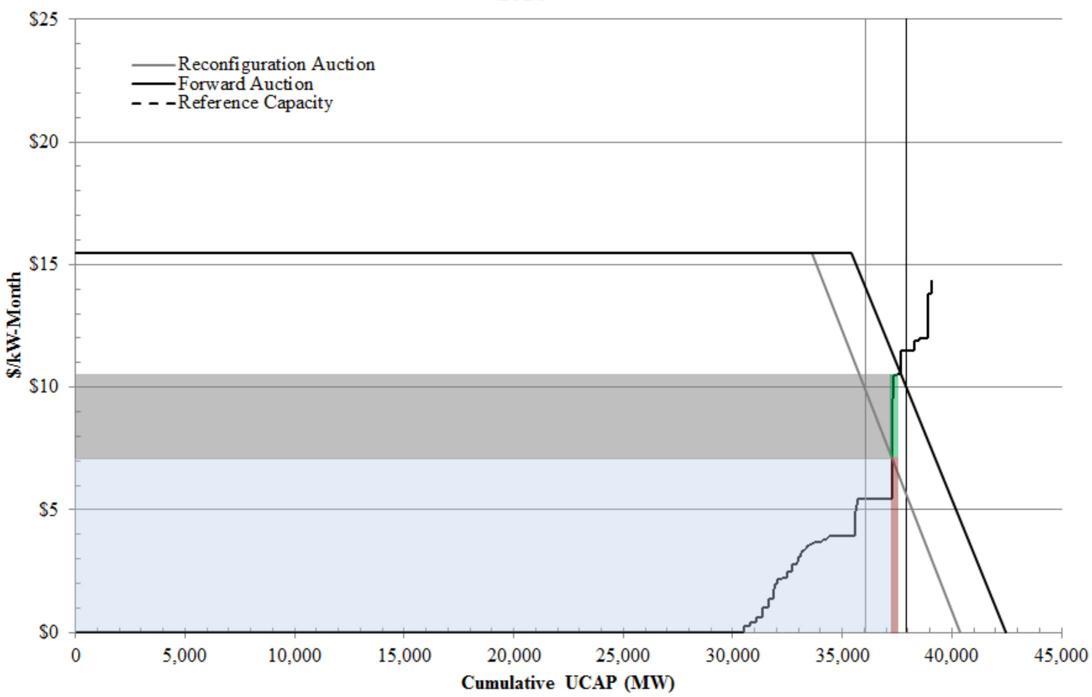


Figure A3.4: Lower than Expected Load Forecast, NYCA
Comparison of FM Auction at Y-3 and Y



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