Integrating Public Policy: A Wholesale Market Assessment of the Impact of 50% Renewable Generation

A Report by the
New York Independent System Operator

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Definitions

Terms used frequently throughout this report are defined below for the reader's convenience. Capitalized terms that are not otherwise defined herein have the meaning specified in the NYISO's Market Administration and Control Area Services Tariff or Open Access Transmission Tariff.

Production Baseline

Describes historical and simulated data representative of actual 2016 energy market performance.

Base Case

Describes historical and simulated data representative of resources' actual 2016 capacity market performance.

Market Study

Refers to the set of simulated data representative of hypothetical energy and capacity market performance.

West

Load Zones A-E; the region commonly referred to as "Upstate" New York.

East

Load Zones F-K, including New York City and Long Island.

Flexible

Describes generators with different upper and lower operating limits that offer a range of output capabilities into the energy markets.

Incremental Renewables

The MW of generation powered by renewable energy in excess of the renewable resources in the Capacity Market Study Base Case and Energy Market Study Production Baseline.

Net Load

The sum of virtual and physical load minus Virtual Supply.

Abstract

The Clean Energy Standard (CES)[1] mandates a shift to 50% electricity production from renewable resources by 2030 ("50-by-30") in New York State. Currently, New York receives approximately 25% of its energy needs from renewable resources. However, large-scale hydroelectric power resources produce the vast majority of this energy. New York expects the incremental renewable electricity production to come from more intermittent power producing resources, such as distributed solar power or wind powered resources. The New York Independent System Operator (NYISO) modeled hypothetical energy and capacity market scenarios to understand the effects that the CES public policy could have on the wholesale markets. Based on its findings, the future grid will be less predictable and require more flexibility than it does today. Intermittent renewables will increase net load uncertainty. Flexible resources will be committed less frequently and cycle more often. The NYISO expects energy prices to frequently clear at or below $0/MWh with the addition of numerous zero variable-cost resources.

Operating characteristics such as availability, flexibility, and willingness to cycle are important to long-term grid stability and will need to be financially rewarded. If the NYISO does not appropriately compensate for these characteristics, the wholesale markets may not provide adequate incentives for the necessary resources to manage future reliability needs. Market design concepts that could address these concerns are under evaluation. Further analysis and concept proposals will be forthcoming in 2018.

[1] Appendix A: Study Methodology, New York Clean Energy Standard

Executive Summary

The New York Independent System Operator (NYISO) is responsible for operating New York's high voltage, bulk power system and administering New York's competitive wholesale electricity markets. Consumers have enjoyed numerous economic and environmental benefits since the inception of NYISO's wholesale markets, including 43% lower carbon dioxide (CO_2) emission rates, 87% lower nitrogen oxide (NO_x) emission rates and 98% lower sulfur dioxide (SO_2) emission rates. (NYISO 2017). Price signals in NYISO-administered markets facilitated these advancements and led to investments in both cleaner generation technologies and the transmission and distribution system, as well as the retirements of older, less efficient power plants.

The NYISO recognizes that financial incentives provided by the wholesale markets will play a vital role in efficiently meeting the State's target to serve 50% of electricity demand with renewable by 2030 (the "50-by-30" goal). In 2017, NYISO staff studied both the energy and capacity markets to identify the market needs that might arise from the significant statewide increase in renewable resources.

The NYISO used its market software to model the energy markets based on the additional renewable generation the CES contemplates in the New York Control Area (NYCA). A full unit commitment and dispatch simulated both the Day-Ahead Market (DAM) and the Real-Time Market (RTM) based on New York's bulk power system (NY Power System) and 2016 market conditions, augmented with additional renewable resources. The analysis evaluated how the 2016 NY Power System might perform with additional renewable resources. The NYISO did not make speculative assumptions about future retirements or transmission upgrades[2] and the NYISO applied current wholesale market products and rules as of 2016.

The results of the energy market study were unsurprising. Energy prices were persistently negative in the Western part of the State and low across the rest of the State. The market study selected existing resources less often to provide energy. New, incremental renewable in front of the meter and behind the meter resources, modeled as Virtual Supply, displaced the currently connected resources. Units dispatched down included conventional hydroelectric, combined cycle, fossil fuel steam turbine and existing wind resources. While all existing resources were committed less frequently to provide energy, some received additional commitments for ancillary services. Transmission limits, high intermittent resource production,

[2] The NYISO has a Comprehensive System Planning Process, which includes a Public Policy Planning process. A full description of how Public Policy Transmission is identified and developed in New York can be found in the NYISO's Public Policy Transmission Planning Process Manual. (NYISO n.d.)

and low net load also contributed to renewable curtailments.

Incremental Renewables, both in front of the meter and behind the meter, reduced net load, *i.e.*, the sum of virtual and physical load minus Virtual Supply. Today, net load typically increases over the course of the day, cresting during the late afternoon and early evening hours before tapering off. The reduction in net load observed in the energy market study corresponded with an increase in net load forecast uncertainty. Net load ramp, a measure of the movement of supply and demand in real time, was much more volatile in the energy market study than it was in the 2016 production cases used for comparison. As a result, the market software was required to react, resulting in significant swings in net load ramp. The market software managed the variability by cycling flexible units and peakers more often, a strategy that can result in long-term equipment degradation. “Flexible” units are generators with different upper and lower operating limits that can supply a range of output into the energy markets.

One of the real-time energy market study cases repeatedly failed to produce rational solutions. This suggests that under potential future conditions, market optimization algorithm changes may be needed to allow the NYISO to continue timely posting commitment and dispatch instructions in real-time. Given that current and forecasted renewable resource penetration levels are not expected to approach the levels used in the energy market study, the NYISO does not expect to encounter optimization algorithm problems like this in the near future.

A first-order capacity market model was used to assess the expected effects of the CES renewable resources entering the existing capacity market framework. The assessment showed that a significant entry of renewable resources will cause the NYISO to increase the megawatts of Installed Capacity required to meet its resource adequacy criteria (*e.g.*, the Installed Reserve Margin and Locational Minimum Installed Capacity Requirements will increase.) Because renewable resources generally have lower availability rates during peak load periods than the current capacity suppliers, the NYISO estimates that approximately four megawatts of CES renewable resources would be required to secure the capacity equivalent of one megawatt of the existing generation fleet. Study results further suggest that if renewable resources do not displace existing capacity suppliers, future capacity prices will likely decrease. The NYISO will consider revising its current capacity eligibility requirements, capacity supplier obligations, and capacity performance assessments to attract and retain resources needed to meet requirements.

The NYISO should prepare for the impacts of State policy by assessing the need for and then implementing wholesale market design changes that foster the continued participation and new entry of resources needed to reliably operate the NY Power System in the future. Study findings indicate that themes like availability, dispatchability (ability to ramp), predictability (ability to forecast load and supply), and flexibility (ability to cycle) will be the focus of future wholesale market evolutions. Failure to recognize these themes in market enhancements may result in an inadequate fleet of resources needed to mitigate reliability risks.

The NYISO will consider a wide range of wholesale market rule modifications and new products in the coming years to prepare for the grid needs of 2030 and beyond. The NYISO will leverage stakeholder feedback, industry experts, experience in other ISOs/RTOs, data from this Energy Market Study and Capacity Market Study, and further analysis to select the most promising market design concepts from the spectrum of possibilities.

Background

New York Clean Energy Standard

The 2015 State Energy Plan (SEP) stated that 50% of all electricity used in New York be generated by renewable resources by 2030[3] (commonly referred to as the "50-by-30" goal). Governor Andrew Cuomo directed the New York State Department of Public Service (DPS) to convert SEP targets to mandated requirements.[4] In the following year, the New York State Public Service Commission (PSC) issued an *Order Adopting a Clean Energy Standard*.[5]

As part of the CES Order, the PSC adopted the SEP's "50-by-30" goal as part of the approach to reduce statewide greenhouse gas emissions 40% from 1990 levels by 2040. As a mechanism to meet that objective, the CES Order establishes a mechanism through which load serving entities in the State support new renewable resources and at-risk nuclear generators. The mechanisms through which support are provided to these resources are the procurement of Renewable Energy Credits (RECs) and Zero Emission Credits (ZECs).

The CES Order applies to all customers in New York, including those served by the State's distribution utilities, competitive energy supply companies (ESCOs, *i.e.*, entities that serve end use load), New York State power authorities,[6] and those served directly by the wholesale energy markets. Existing resources and energy efficiency investments apply toward the "50-by-30" goal.

Renewable Energy Targets in the CES Order

The CES Order sets minimum energy procurement targets in megawatt-hours (MWh) from renewable resources each year. Incremental renewables (*i.e.*, "Tier 1" resources) eligible to apply toward these targets include behind the meter and utility-scale solar, wind turbines, small hydroelectric turbines and biomass combustors. The CES Order notes that a parallel process will develop the State Resource Plan to determine whether other NY Power System changes are needed to reach SEP targets, including the need for additional transmission.[7]

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[3] *The Energy to Lead*, 2015 New York State Energy Plan.

[4] *Staff White Paper on Clean Energy Standard*, New York State Department of Public Service, January 25, 2016.

[5] State of New York Public Service Commission Case Nos. 15-E-0302 and 16-E-0270, Proceeding on Motion of the Commission to Implement a Large-Scale Renewable Program and a Clean Energy Standard, *Order Adopting a Clean Energy Standard* (issued August 1, 2016) (CES Order).

[6] The CES Order states at p. 27, "b. Non-Jurisdictional Entities: Staff states that NYPA and LIPA are expected to adopt renewable and non-emitting energy targets that are proportional to their load. This includes municipal utilities and rural cooperatives that obtain their full requirements from NYPA. The CES obligation of jurisdictional entities would be calculated under the assumption that NYPA and LIPA are adopting their proportional shares of the statewide goals."

[7] CES Order at p. 24

Energy Market Study

Higher renewable resource penetration will affect how the NY Power System performs, how market participants behave, and market outcomes. In order to continue to meet its responsibilities, the NYISO must prepare for and adapt to the increased level of renewable resources. The NYISO's market solution tools are uniquely equipped to explore what could happen if the renewable resource mix changes in response to State energy policy. An offline instance of the market software was used to explore the impact that presumed renewable resource additions might have on both the DAM and RTM outcomes.

Background and Assumptions

The NYISO did not undertake a planning study. No attempt was made to predict the optimal locations for new resources. The study did not analyze speculative or anticipated retirements, changes in transmission equipment, or other variables that could change the landscape of the NYCA. Instead, the NYISO modeled the effects that the projected quantity of renewable resources could have on the NY Power System and energy markets exactly as they existed in 2016. "Incremental Renewables" refers to the modeling of additional renewable resources (in excess of the current renewable base) discussed throughout this report. This approach informs the NYISO and its stakeholders of the operating characteristics that may be needed from other generation resources to maintain grid reliability in the future. Study results will guide the development of appropriate market incentives to attract and retain resources that can provide those attributes.

Days Modeled

One typical day from each season (spring, summer, winter, and fall) of 2016 was selected for analysis. The term "Market Study" describes solutions developed for hypothetical scenarios on those days. Solutions that rely on the NYCA's 2016 generation mix were used as a basis for comparison and are referred to as the "Production Baseline" throughout this report. The NYISO executed a full unit commitment and dispatch for each scenario. The commitment and dispatch selected generators to provide services within their specific capability range and to meet NY Power System reliability needs at the lowest cost.

Figure 1: Days Selected for Energy Market Study

Study Day	Peak Load Forecast (MW)	Peak Load Hour	High-Low Temp. ALB/LGA*	Gas Prices TNZ6/TZ6NY**	Other
Tuesday, January 19, 2016	22,168	18:00	23-13/29-18	$4.20/$6.25	Winter Peak
Tuesday, March 22, 2016	18,638	20:00	51-27/55-35	$2.02/$1.30	IP2 Refueling***
Monday, July 25, 2016	31,401	16:00	89-68/91-81	$2.91/$2.83	High Load
Thursday, November 10, 2016	19,131	17:00	51-31/57-43	$2.45/$1.90	High Wind

*High and Low temperatures were recorded at Albany International Airport (ALB) and LaGuardia International Airport (LGA).

**TNZ6 prices apply to zones F-I, while TZ6NY prices apply to zones J-K.

***Indian Point 2 is a large (~1,000 MW) nuclear generator located in zone H. It was offline for refueling on March 22, 2016.

Incremental Renewables in the Energy Market Study

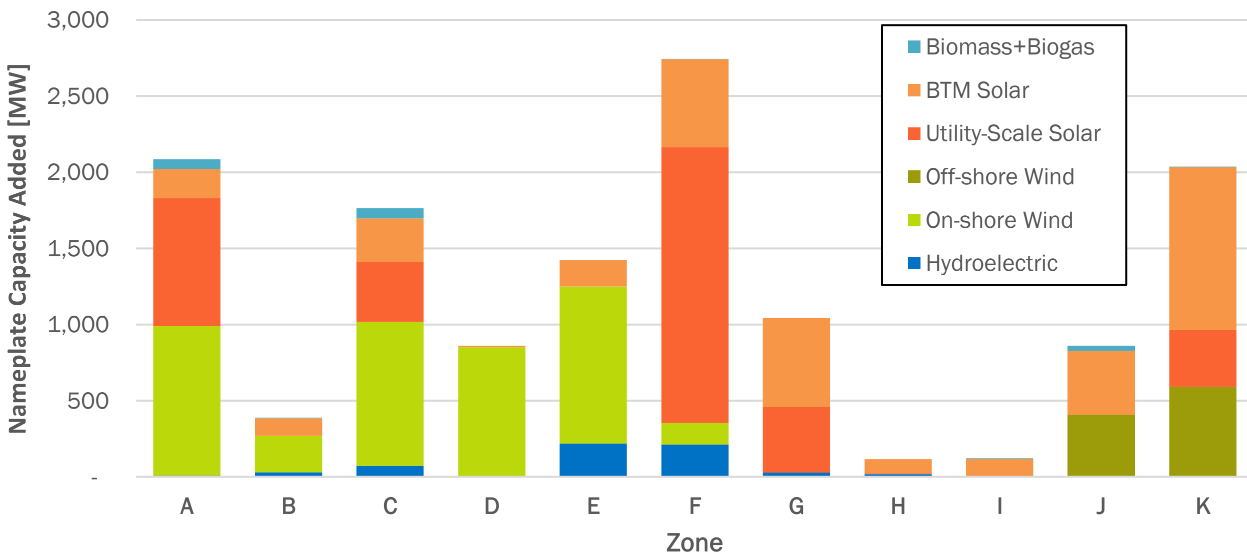
The NYISO relied on the Final Supplemental Environmental Impact Statement (Final EIS)[8] for guidance on the estimated quantity and location of Incremental Renewables. The Final EIS estimates needing a portfolio of new large-scale renewables totaling approximately 29,000 GWh/year of front of the meter resources and 5,000 GWh/year of behind the meter solar generation to reach the State's goals.

To approximate the quantities presumed in the Final EIS, the Market Study adds 13,444 MW of renewable nameplate capacity to the 8,108 MW already existing in the NYCA. Figure 2 details where that renewable capacity was modeled, by zone.[9] Front of the meter Incremental Renewables were allocated to each zone according to the estimates provided in the Final EIS, and behind the meter Incremental Renewables were allocated in direct proportion to the distribution of existing behind the meter renewable resources. Within each zone, both front of the meter and behind the meter Incremental Renewables were represented as if they were spread across each zone in direct proportion to the zonal load distribution.

[8] (New York State Department of Public Service 2016)

[9] Appendix A: Study Methodology, Assumptions, Renewable Capacity Added for Energy Market Study.

Figure 2: Zonal Distribution of Incremental Renewable Capacity Added to the NYCA for Market Study Simulations



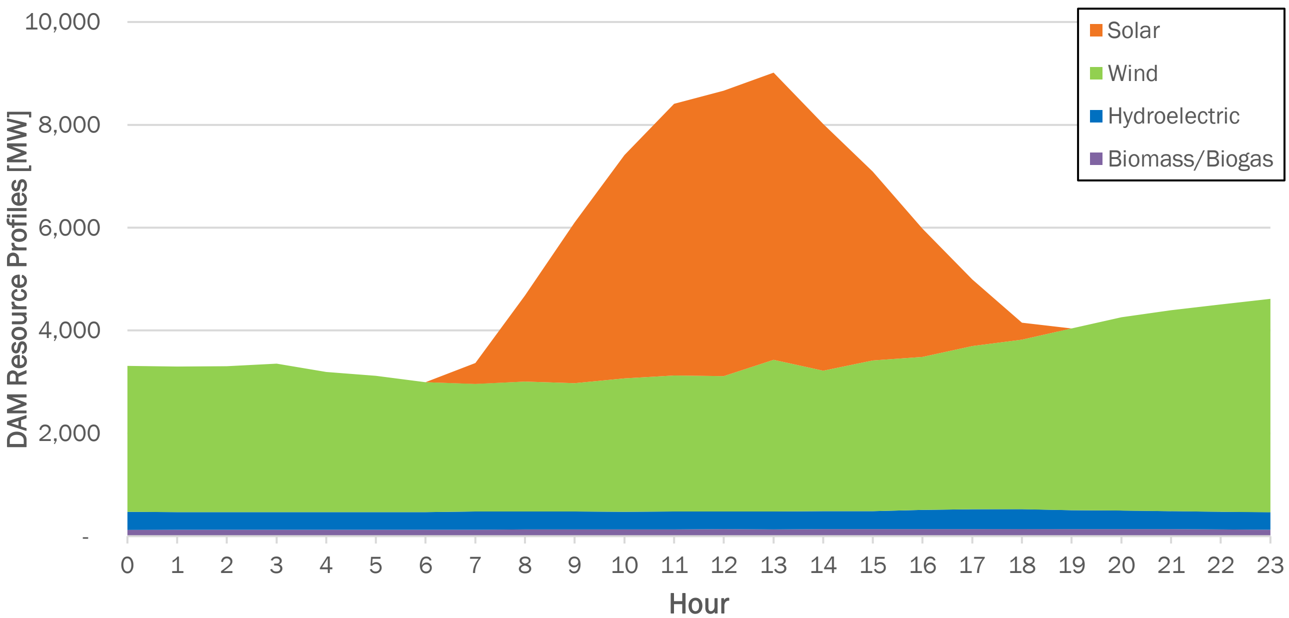
Generation Output Profiles of Incremental Renewables

Zonal generation output profiles were created for each class of Incremental Renewables in order to model both their forecast and actual performance in the Market Study simulations. DAM Market Study Incremental Renewable generation output profiles were created using the existing Day-Ahead forecasts used for the same renewable types on the Production Baseline days. RTM Market Study Incremental Renewable generation output profiles were created using the real-time Production Baseline output.[10] Figure 3 shows the statewide aggregate profiles of Incremental Renewable MW generation output used in the March DAM Market Study.

[10] A detailed explanation of the methods used to create zonal distributions and output profiles is in

Appendix A: Study Methodology.

Figure 3. Incremental Renewable Profiles in the DAM Market Study, March Day



Output profiles for other DAM and RTM Market Study cases were similar in shape. Solar profiles peak around midday. Wind profiles vary based on the forecasts for each Production Baseline day. Hydroelectric and biomass contributions had little effect on the overall Incremental Renewable output.

Time Horizon for the Real-Time Market Study

Market Study solutions are provided for RTM intervals between 00:30 and 21:40. The NYISO's real-time software relies on information from the prior day to develop the commitment and dispatch instructions for 00:00 to 00:30 and information about the next day to develop the commitment and dispatch instructions for 21:40 to 23:55. The Market Study days were single-day studies; therefore, no information was available to the NYISO's offline software about the prior or future days.

Pricing Assumptions

The existing transmission system limits the amount of energy that can flow across New York at any given time. A significant bottleneck, referred to as Central East, persistently forms around a group of transmission facilities. The Market Study reports average Locational Marginal Based Prices (LBMPs) for the load zones West and East of this constraint, where "West" refers to Load Zones A-E, and "East" refers to Load Zones F-K. The severity of congestion along Central East is evident in price separation between West and East.

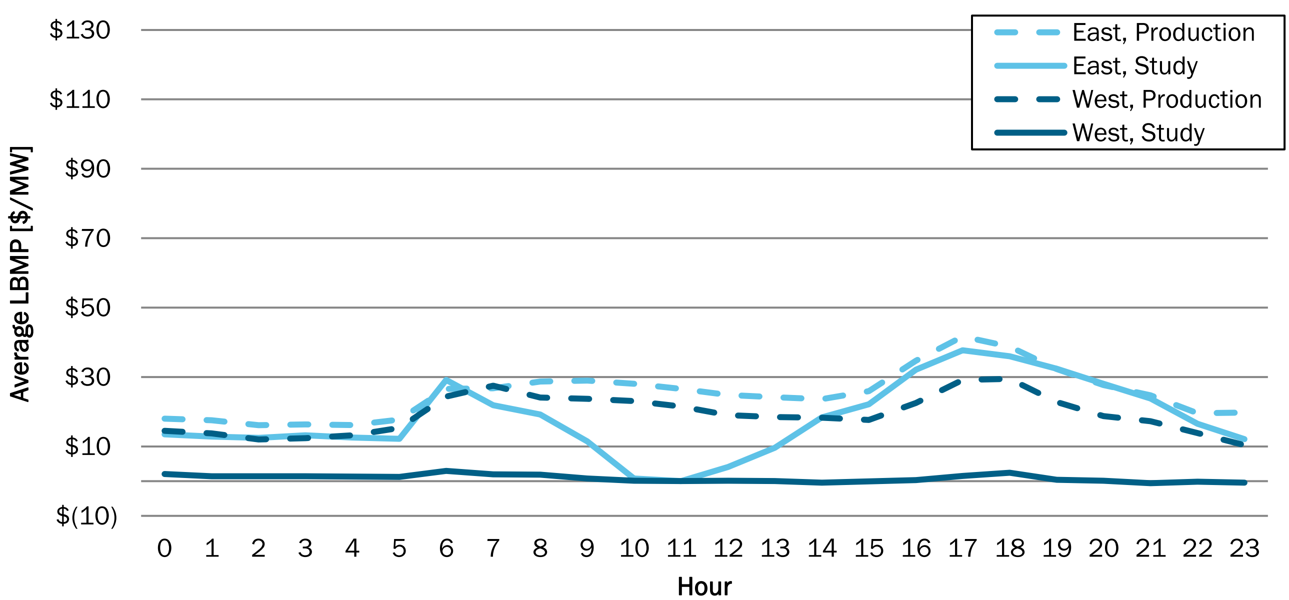
Relative price differences and trends reported between West and East may be indicative of future NY Power System needs, but the Market Study clearing price values are not predictive of future clearing prices.

For example, prices at or near negative $47/MWh appeared in intervals when modeled renewable resources were on the margin. Negative $47/MWh was chosen as the offer floor for Incremental Renewables because that is the point at which qualifying renewables are price sensitive today. How this value may change in the future is difficult to determine, but the conditions that arose in the Market Study are still relevant.

Discussion of Energy Market Results

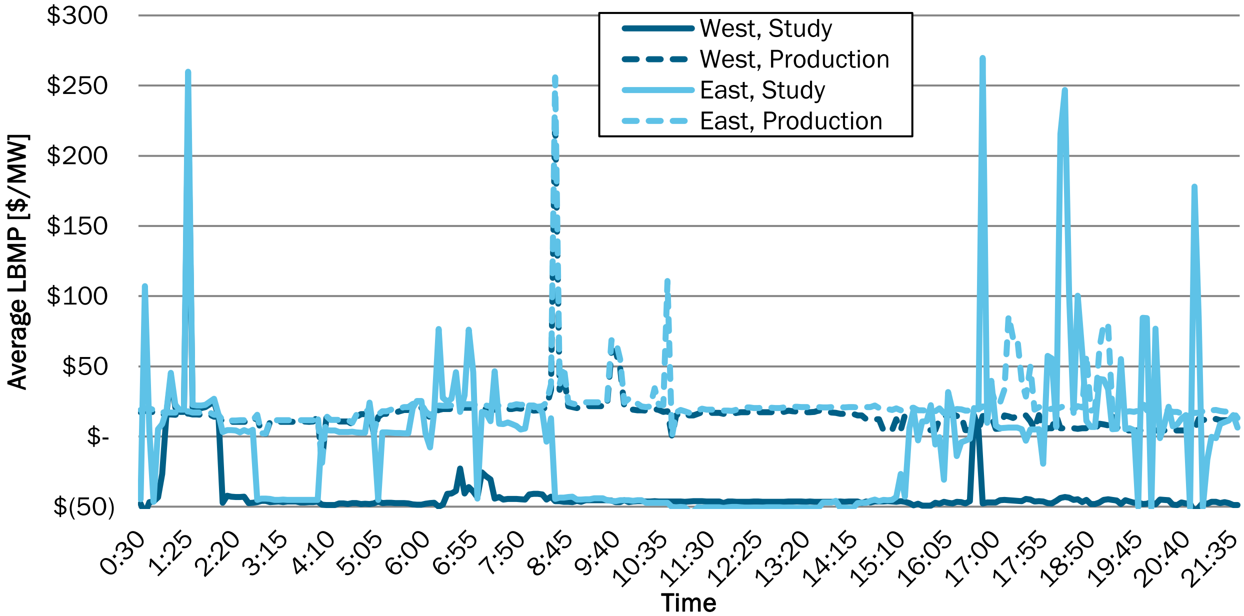
November 10, 2016 was a low-load shoulder-period day with high winds. In the DAM Market Study simulation, net load and energy prices dipped as forecast solar output crested. Similar trends materialized on the other Market Study days. During the morning and evening hours, there was little to no forecast solar generation, driving East prices closer to 2016 levels. Prices in the West were persistently low due to high renewable output in those zones.

Figure 4: Average DAM Energy Prices, November Day



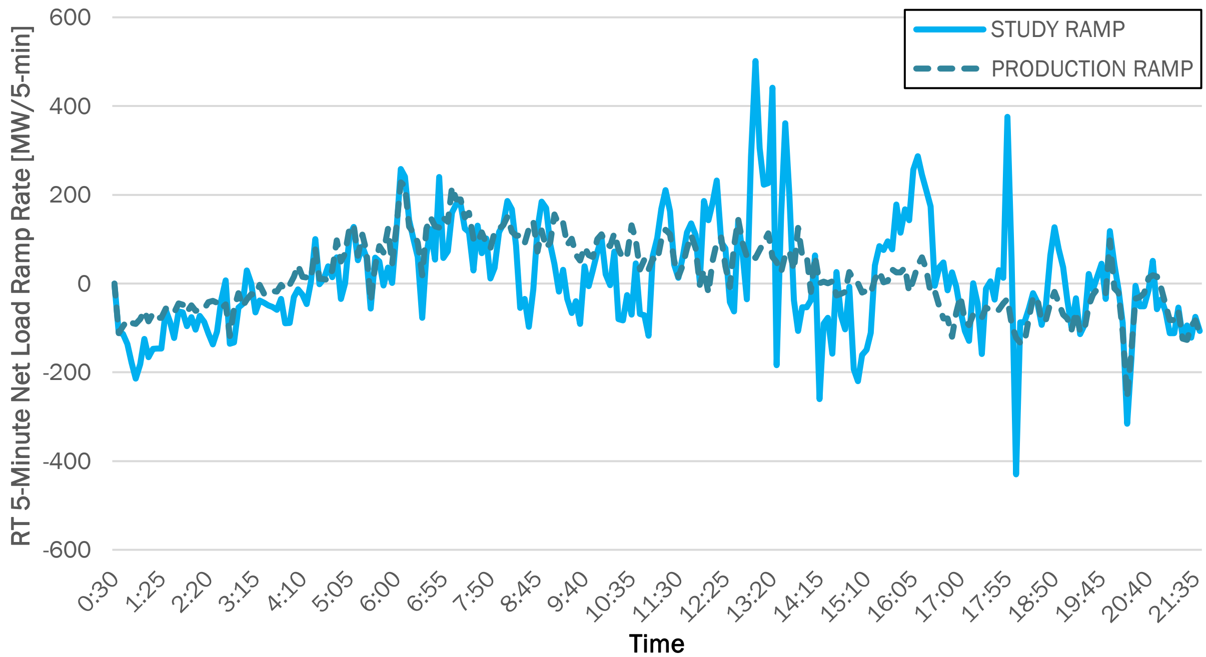
RTM prices in the November Market Study stayed at or below the marginal value assigned to Incremental Renewables (negative $47/MWh) in the West all day and during most daylight hours in the East. East prices were higher during the morning and evening, when solar output was lower. Because fewer flexible generators were committed in the DAM, East prices spiked during intervals with sudden, unforeseen increases in net load.

Figure 5: Average RTD Energy Prices, November Day



As intermittent renewables respond to changing weather conditions, other generation resources must also react rapidly to serve load. Net load ramp, an indicator of supply and demand volatility, is calculated as the difference in load from one five-minute real-time interval to the next. The larger the step in net load ramp between intervals, the farther dispatchable generation resources have to move to support the reliable operation of the NY Power System. Figure 6 illustrates the dramatic increase in real-time net load ramp volatility observed in the July Market Study as compared to the 2016 Production Baseline.

Figure 6: Net Load Ramp, July Day



Net load ramp is an important factor in commitment decisions made by the NYISO's Real-Time Commitment (RTC) software. For example, when RTC perceives that generator availability is lower than what will be required to meet the expected load over the next 30 minutes, it may instruct additional fast-start units to turn on. In subsequent intervals, if output from intermittent renewables increases significantly, RTC may de-commit the same resources after minimum run times have been met because their output is no longer needed.

RTC manages load uncertainty primarily by cycling traditional units capable of turning off and on in the necessary timeframe. Real-time starts per day are expressed as a ratio comparing the Market Study to Production Baseline cases in

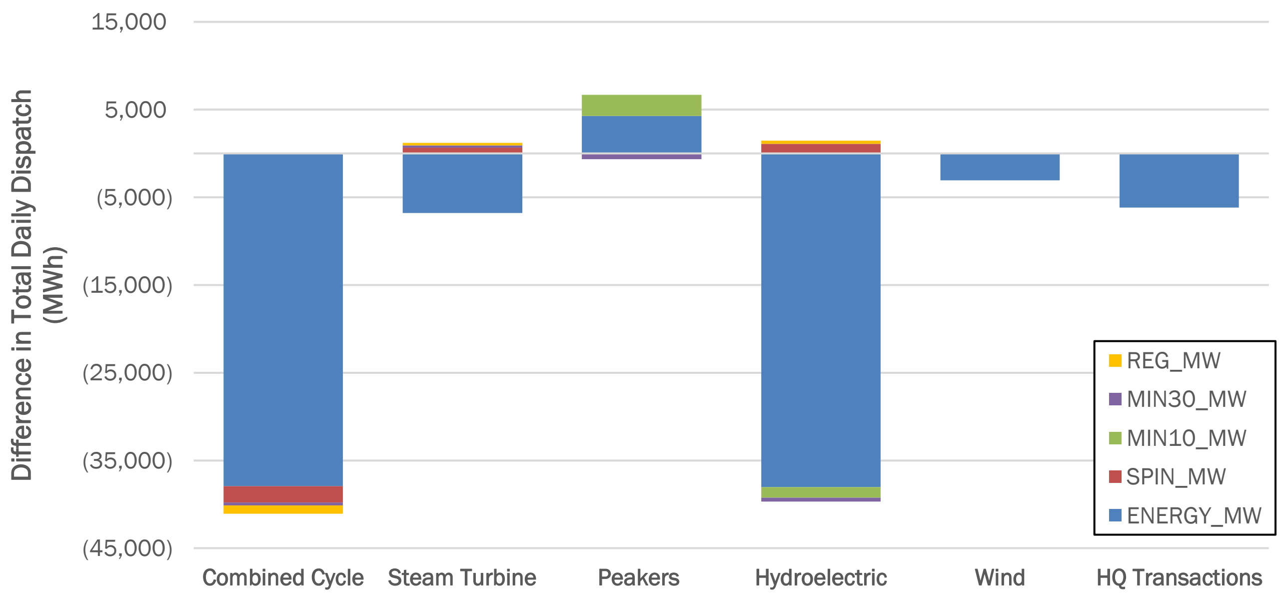
Figure 7. The increase in cycles was least apparent on the July Market Study day, when load was high and traditional generators remained on during peak solar hours.

Figure 7: Ratio of Real-Time Starts per Day in the Market Study to Production Baseline (DAM and RT Committed Units)

Resource Type	March	July	Nov.
Combined Cycle	2.2	1.6	2.7
Peakers	1.4	1.1	3.3
Hydroelectric	3.5	2.2	3.0

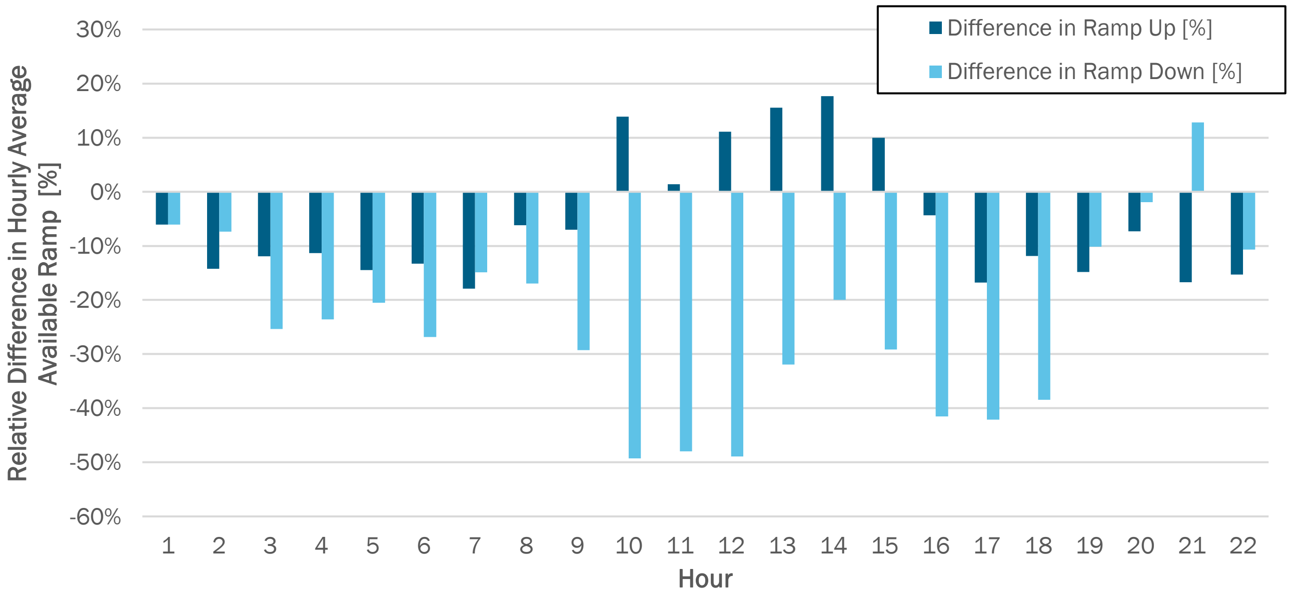
Although more flexible units remained online during the July Market Study day, a dramatic difference in their real-time dispatch was observed when compared to the Production Baseline. A similar trend was observed for Day-Ahead commitments. While the NYISO did not forecast any retirements in this study, it is likely that some of the units in the Market Study might exit the markets in a future with more frequent negative energy prices, more frequent on/off cycles (which can cause equipment degradation), and less frequent commitment. Therefore, it will be important that the wholesale markets evolve to value the traits necessary to manage the grid with large amounts of renewable generation.

Figure 8: Real-time Unit Dispatch (Market Study- Production Baseline), July Day



In the Market Study, flexible generators like combined cycle power plants were dispatched down near their lower operating limits or turned off as solar output rose each day. When solar production tapered off in the evening, flexible units were dispatched back up. The total down-ramp available to the market software was higher when flexible units were online and operating above their minimum generation levels. Similarly, up-ramp availability was higher when flexible units were online and operating below their maximum generation levels. This is most easily observed on the July Market Study day, when flexible generators were needed during high peak demand because renewables alone could not fully serve the load. A significant reduction in flexible resource ramp availability was still observed, particularly down-ramp availability. The results from the March and November cases showed more severe reductions in online flexible resources.

Figure 9. Relative Change in Flexible Generator Ramp from Production Baseline to Market Study, July



Generally, intermittent renewables can be curtailed quickly. This analysis did not consider curtailing renewable resources when calculating available down-ramp. The inclusion of intermittent renewables in the down-ramp calculations would change the results significantly. For example, during hour beginning ten (10) on the July Market Study day, the available ramp from flexible generators was approximately 760 MWh (48%) lower than it was during the same hour on the July Production Baseline day. However, front of the meter renewable resource output in the Market Study was approximately 4,000 MWh. It is likely that 760 MWh of the online front of the meter renewable resources could have been curtailed, if necessary, to provide down-ramp. However, down-ramp may be needed in specific locations to solve generation over-supply constraints. If renewable resources are located such that they cannot be used to alleviate local over-supply events, their ability to ramp down may not always be available to the market software when needed.

On the November Market Study day, wind penetration exceeded 50% of total load in some intervals, at which point it was limited by transmission bottlenecks. The majority of the State's conventional hydroelectric units were also curtailed because they are located West of Central East. Even if the desired quantity of new renewable resources is added to the NYCA by 2030, their full benefits will not be realized unless new transmission or local storage resources are built, or the new resources are located near load centers.

Figure 10 and Figure 11 display the absolute and relative changes in real-time output of existing wind and conventional hydroelectric resources between the Production Baseline and the Market Study cases for the November day. Both forecast wind output and real-time wind curtailments were higher on the November day than the other study days.

Figure 10: Difference in Real-Time Average Hourly Wind Output, November Day (Market Study-Production Baseline)

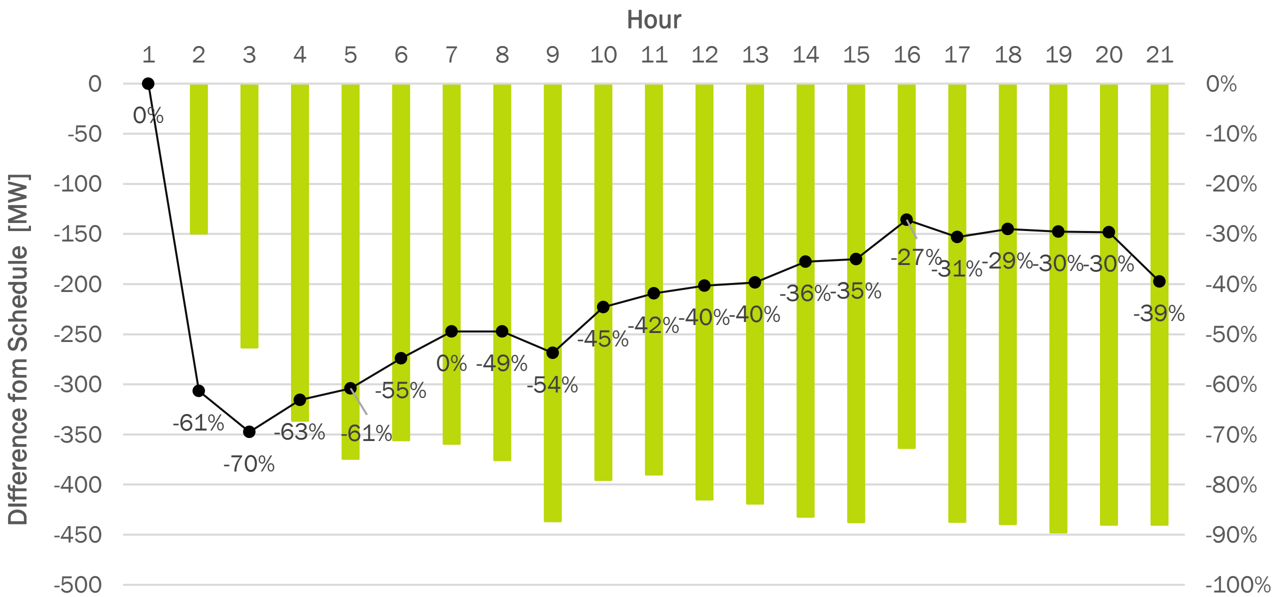


Figure 11: Difference in RT Average Hourly Hydroelectric Output, November Day (Market Study-Production Baseline)

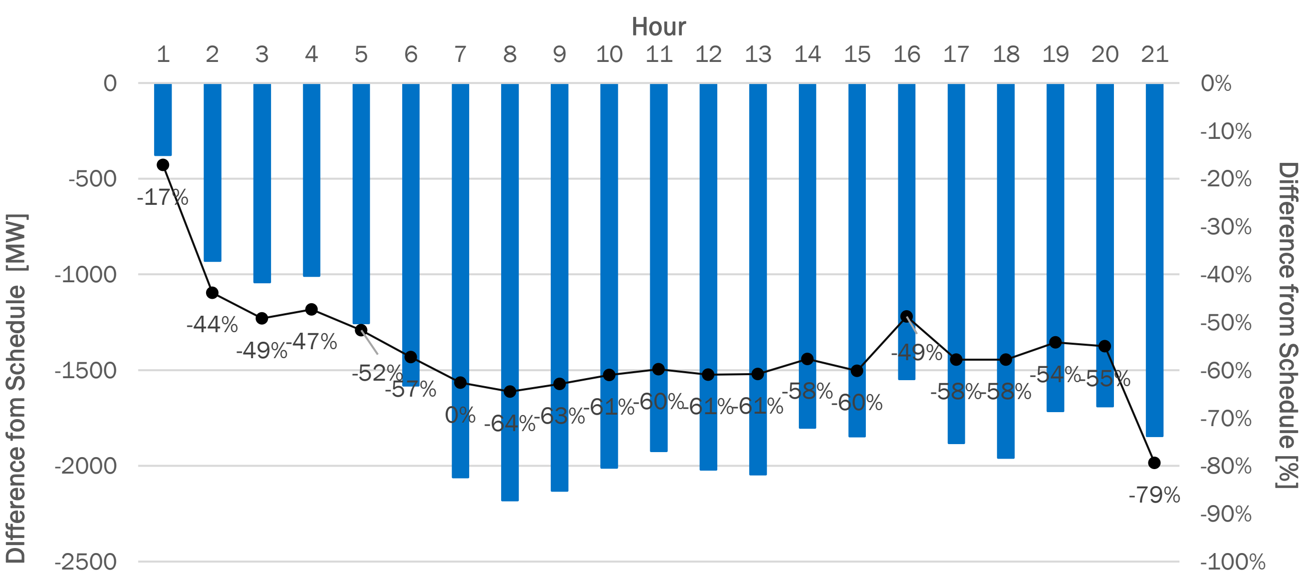


Figure 12 compares the real-time bid energy of front of the meter Incremental Renewables to their scheduled output on the November day. Because front of the meter Incremental Renewables were modeled as having offered at their anticipated output levels, the difference between offered and scheduled energy is equivalent to the available Incremental Renewable energy that was not fully utilized due to NY Power System constraints and/or low net load. The largest differences between bid and scheduled energy notably coincided with maximum solar output on the March and November Market Study days. Load was high enough that Incremental Renewables were almost fully deployed on the July Market Study day.

Figure 12: Real-Time Average Hourly Schedules of Incremental Renewables in the Market Study, November Day

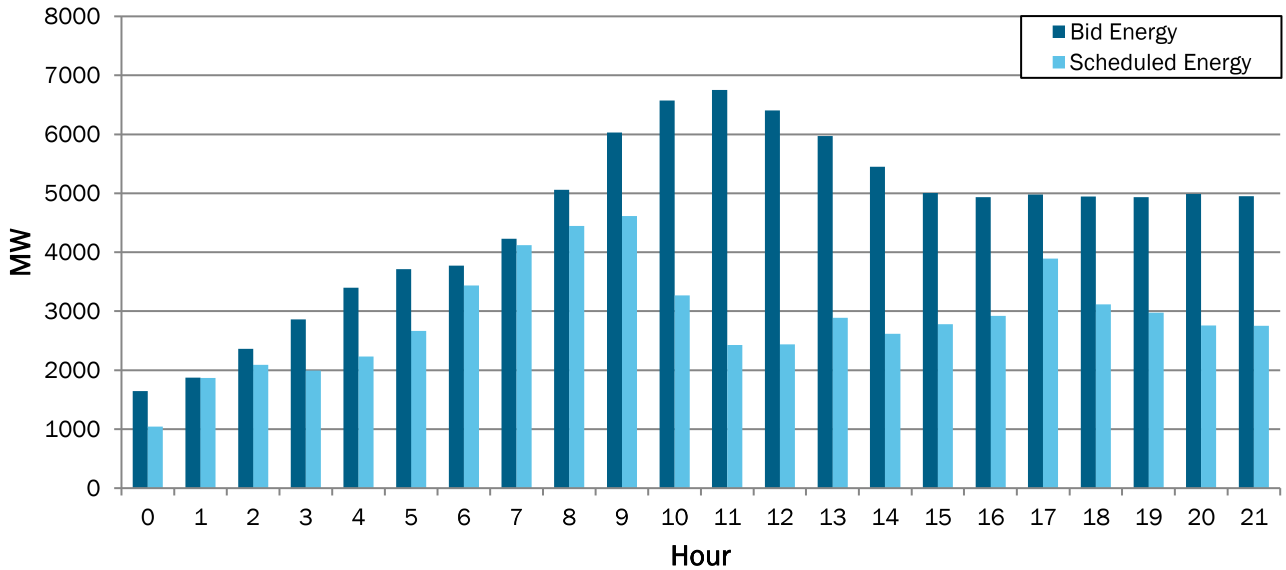


Figure 13 and Figure 14 show the difference between the total energy that could have been delivered by Incremental Renewables and what was scheduled for each RTM Market Study case.

Figure 13. Available Incremental Wind Energy Not Deployed in the RTM Market Study [MWh]

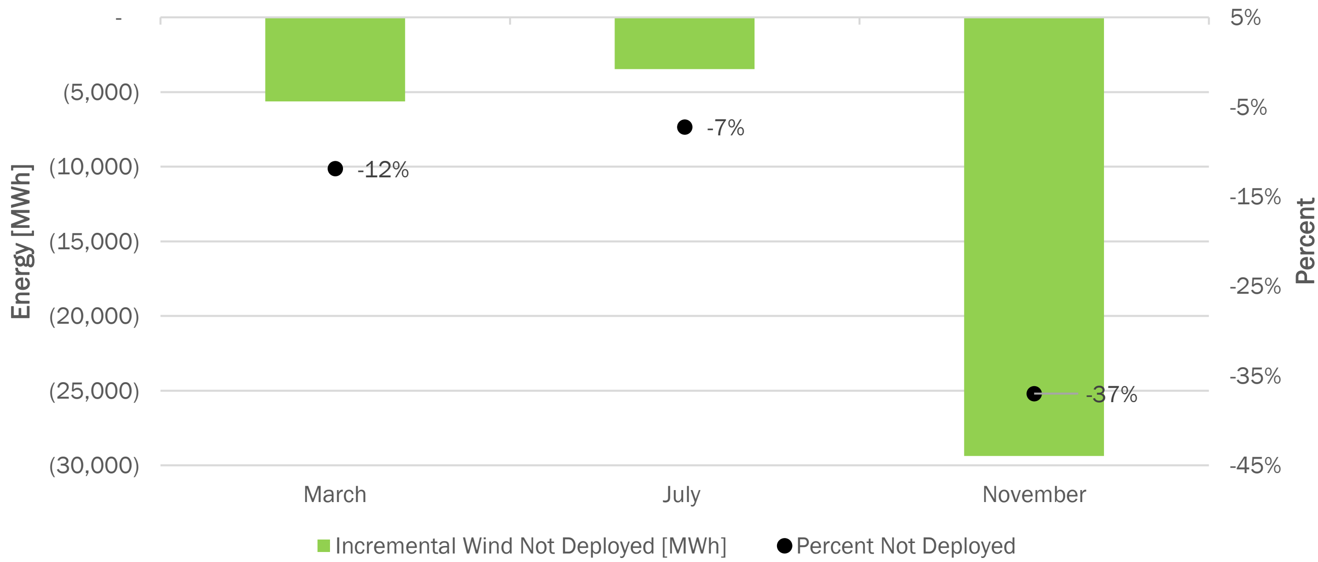
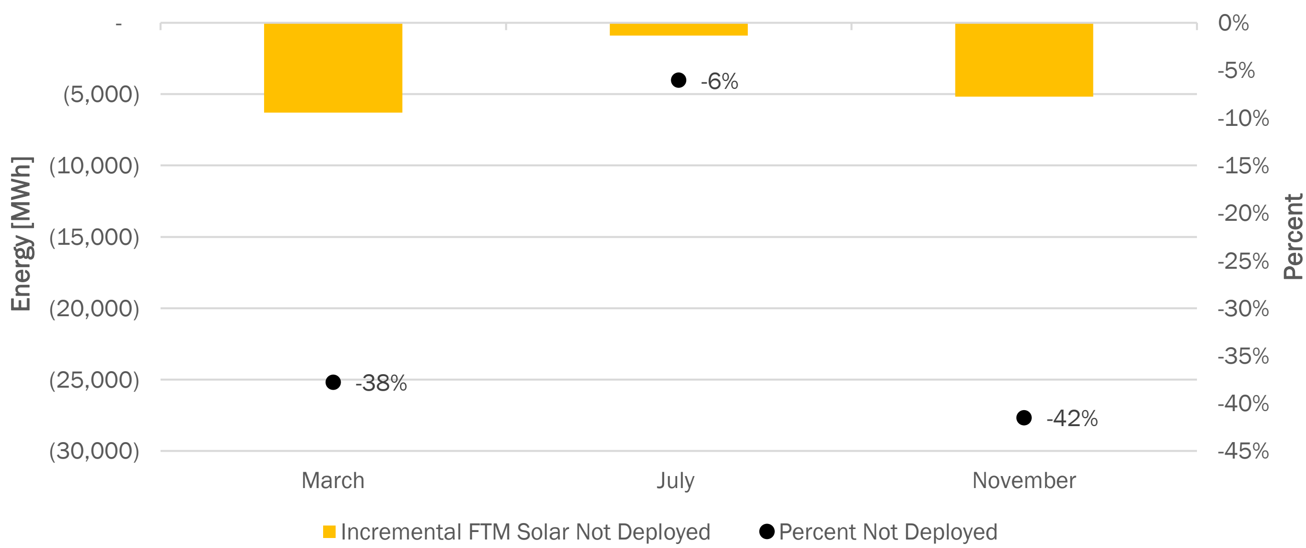
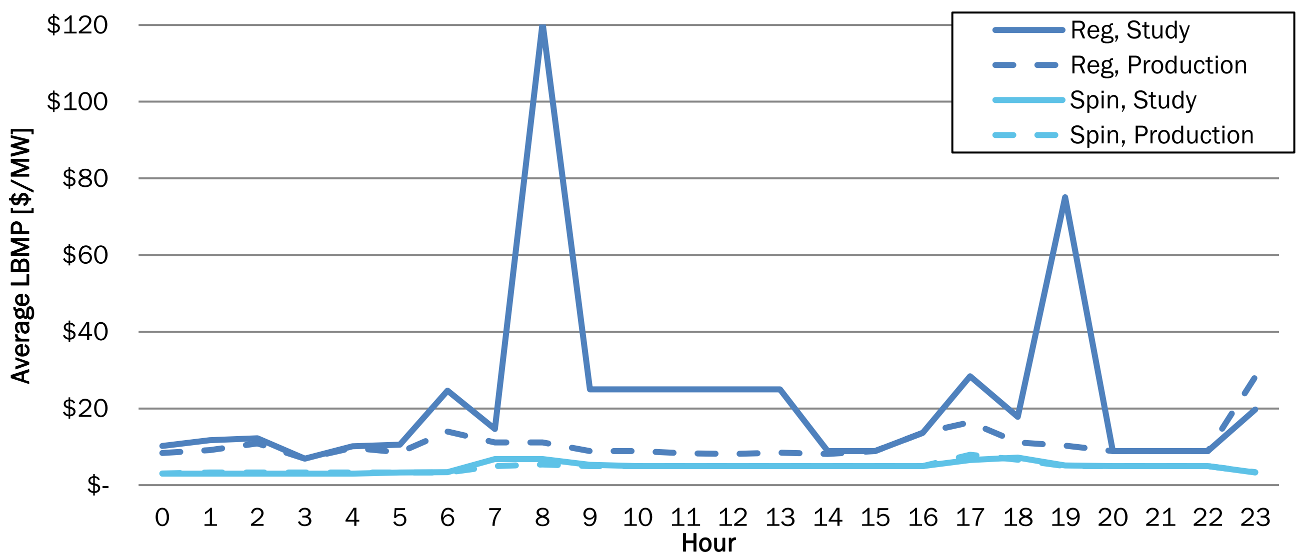


Figure 14. Available Incremental Solar Energy Not Deployed in the RTM Market Study [MWh]



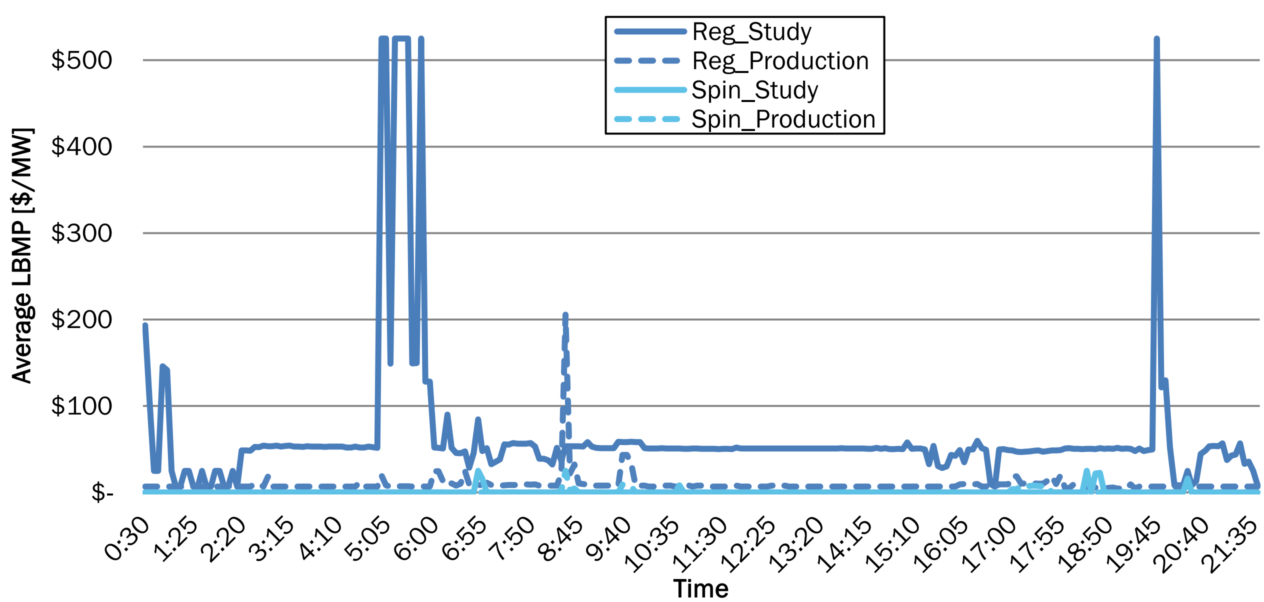
In the November DAM Market Study, fewer resources with the ability to follow a Regulation signal were committed, which caused Regulation to clear at much higher prices in some hours than it did in the Production Baseline day. At hour beginning eight (8), the DAM Market Study Regulation price climbed to $120.61/MWh. East Spinning Reserve prices remained relatively flat.

Figure 15: Average DAM Regulation and East Spinning Reserve Prices, November Day



In real-time, the Regulation price increased to $525.00/MWh during multiple morning intervals of the November Market Study day. A Regulation shortfall greater than 80 MW caused the Regulation demand curve to set the price. The NYISO uses demand curves to price shortages of products when no marginal resources available. Despite higher demand for regulating resources, the clearing prices for other ancillary service products remained near Production Baseline levels.

Figure 16: Average RTD Regulation and East Spinning Reserve Prices, November Day



Regulation Service helps the NYISO maintain NY Power System frequency, and is procured to meet the necessary load variability within a five-minute real-time interval.[11] The relative increase in load ramp variability from one interval to the next across all Market Study cases as compared to the Production Baseline is presented in Figure 17. On the November Market Study Day, there was a 145% increase in the range of load ramp between real-time intervals. A 44% increase was observed on the July Market Study Day. There was little difference between the Production Baseline and Market Study cases on the March day. The NYISO expects to revisit Regulation Service requirements to incent additional grid flexibility and minimize shortages like those observed in Figure 16 as intermittent renewable penetration increases.[12]

Figure 17: Real Time Load Ramp Ranges

Study Day	Production Baseline				Market Study				Difference in Range	
	Avg Load Ramp [MW]	Max Load Ramp [MW]	Min. Load Ramp [MW]	Range [MW]	Avg Load Ramp [MW]	Max Load Ramp [MW]	Min. Load Ramp [MW]	Range [MW]	Range [MW]	Range [%]
March	10	610	-130	740	5	511	-215	726	-14	-2%
July	17	379	-267	646	11	502	-430	932	286	44%
November	12	257	-121	378	0	615	-310	925	547	145%

Capacity Market Study

Similar to the Energy Market Study, the objective of the Installed Capacity (ICAP) Market Study[13] was to understand how an increase in the megawatts of renewable capacity might interact with ICAP market rules and change ICAP market outcomes. A "Base Case" representative of 2016 market conditions was compared to a hypothetical "Market Study" scenario with renewable capacity equal to that targeted in the CES Order and described in the Final EIS. The same mix of Incremental Renewables used in the Energy Market Study was modeled. The Capacity Market Study incorporated direct effects, such as changes in the average performance of capacity suppliers, but did not attempt to anticipate other market responses, such as new or expanded transmission infrastructure, resource retirements, or changes in import and export patterns.

Figure 18 lists the MW of nameplate capacity that was added for the Capacity Market Study, by

[11] NYISO Regulation Requirements are posted on the NYISO website: http://www.nyiso.com/public/webdocs/market_data/reports_info/nyiso_regulation_req_sum04.pdf.

12 The NYISO's 2016 Solar Integration Study contains a recent analysis of current and future Regulation requirements: http://www.nyiso.com/public/webdocs/markets_operations/services/planning/Documents_and_Resources/Special_Studies/Special_Studies_Documents/Solar%20Integration%20Study%20Report%20Final%20063016.pdf

[13] The Installed Capacity Market Study is in Appendix A.

location. This study also assumed that the Incremental Renewables would obtain Capacity Resource Interconnection Services (CRIS), which is required in order to participate in the market.[14] Approximately 3,100 MW of behind the meter solar capacity was also added, but was not included as part of the total capacity supply because it was modeled as an adjustment to load. Details about the assumptions and methodology used for the Capacity Market Study may be found in Appendix A: Study Methodology, Capacity Market Study Methodology

Figure 18. Nameplate Installed Capacity Added for Capacity Market Study

Load Zone(s)	Nameplate MW Added
A-F	8,978
GHI	905
J	1,235
K	2,326
A-K (NYCA)	13,444

Incremental Renewables can be expected to directly affect key ICAP market parameters.[15] Key areas of relevance were impacts Incremental Renewable resources might have on the Installed Reserve Margin (IRM), how their performance during peak load periods could affect Locational Minimum Installed Capacity Requirements (LCRs), and how they might affect the parameters that determine the ICAP Demand Curve Reference Point. Details about the assumptions and methodology used for the Capacity Market Study may be found in Appendix A: Study Methodology, Capacity Market Study Methodology

Discussion of Results of Key Areas

The NYISO would require a greater number of nameplate megawatts of capacity to meet resource adequacy criteria after the entry of the Incremental Renewables (*i.e.*, the Installed Reserve Margin and Locational Minimum Installed Capacity Requirements would increase.) This increase is due to the fact that renewable resources have lower availability during peak periods than the current set of capacity resources. As a result of their lower average availability, renewable resources could not displace today's fleet average capacity on a one-for-one basis. For the levels of renewable entry in this study, the study's first-order estimates suggest that four megawatts of Incremental Renewables could displace approximately one megawatt of today's fleet average capacity.[16] It is likely that the attributes of the individual renewable

14 That assumption differs from the percent of renewable resources that have entered the NYCA in recent years that obtain CRIS.

15 For example, the annually-established minimum capacity requirement tends to vary as a function of the average performance of the supply of capacity.

16 Specifically, the ICAP Market Study performed a sensitivity that returned capacity prices to current price levels. The results of this sensitivity identify the quantity of today's fleet average capacity that could remain 'uncleared' in the ICAP Spot Market Auction but is present in the market (*e.g.*, represented during the requirement setting process) as a result of the Incremental Renewables. .)

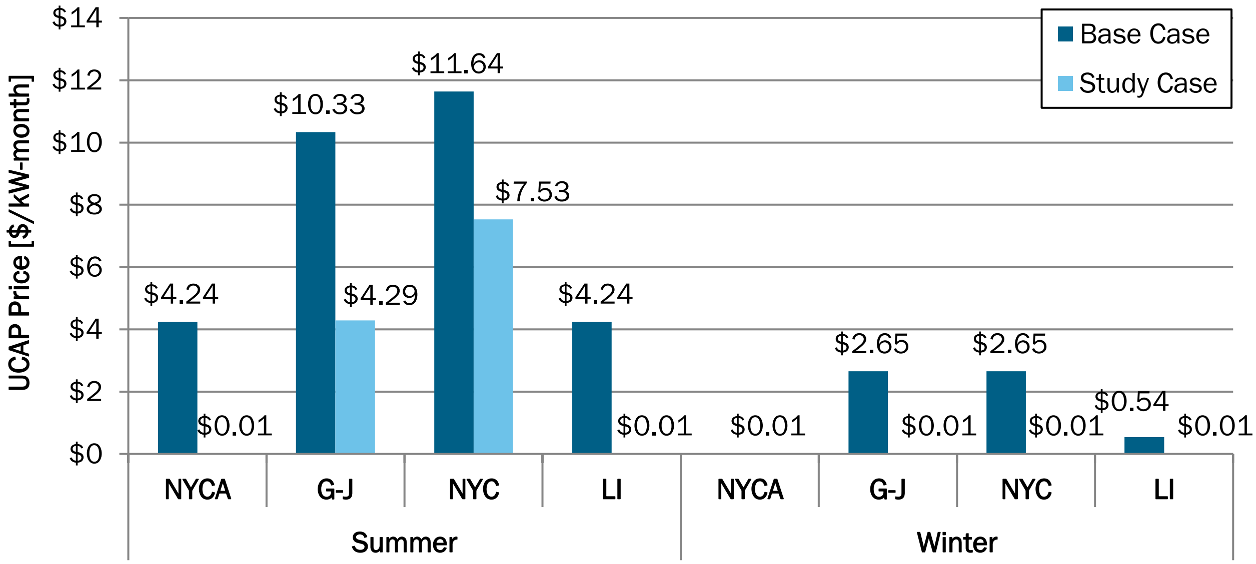
resources (or generator technologies) could affect the amount of megawatts (or technology type) of today's fleet that are displaced. For example, solar has greater availability during today's on-peak periods in the Summer Capability Period than onshore wind and thus may be able to displace a greater quantity of today's fleet average capacity than onshore wind. The study results further suggested that if Incremental Renewables do not displace other, existing capacity, then capacity prices will likely decrease substantially relative to current prices. That is, the capacity revenue available will decrease if total capacity cleared in the market includes all of today's existing capacity and the Incremental Renewable. The following paragraphs discuss the effect of Incremental Renewables on market measures and outcomes related to the total supply of, and demand for, capacity in the NYISO ICAP market.

Market Study Case ICAP requirements remained flat, except for an increase in the NYCA-wide minimum ICAP requirement. Unforced Capacity (UCAP) requirements fell in all locations. The observed changes in capacity requirements were related to two variables: First, the Incremental Renewables were characterized by lower availability, on average, than the Base Case resources. As a result, Market Study Case reserve margins were substantially greater than Base Case reserve margins, which directly increased the NYCA-wide ICAP requirement. Second, the added resources included substantial quantities of behind the meter solar panels. Current market rules treat these behind the meter resources as an adjustment to load and, by extension, the ICAP Requirement. These behind the meter solar resources cannot concurrently reduce metered peak demand and sell capacity into the wholesale market.

The Market Study Case UCAP Demand Curves' respective reference point, *i.e.*, the capacity prices at the minimum capacity requirement, were higher in the Market Study. This increase was driven by the assumed reduction in net energy revenues earned by the peaking plant utilized to establish the current Demand Curves. Market Study Case UCAP Demand Curves were also steeper than Base Case curves despite larger reserve margin requirements. Summer supply and demand balances shifted as a result. Incremental Renewables were added in all locations and, thus, capacity supply in the Market Study exceeded Base Case supply in all locations. Capacity demand, the product of peak load and the capacity requirement, was either similar to or lower than in the Base Case. Shifts in supply and demand balances were most pronounced in satisfying the NYCA-wide requirement and in Long Island.

As expected, capacity prices decreased substantially relative to Base Case capacity prices. With the exception of NYC and the G-J Locality during the Summer Capability Period, low prices indicate that the Market Study Case was oversupplied with capacity relative to what was needed to meet reliability requirements. Increases in UCAP supply without commensurate increases in UCAP demand put downward pressure on prices in all locations.

Figure 19: UCAP prices in the Base Case and the Market Study Case



The ICAP Market Study was discussed with stakeholders during three Installed Capacity Working Group (ICAPWG) meetings,[17] during which the views articulated by stakeholders were consistent with those of the NYISO: that the existing capacity market framework reacted predictably to the additional renewable resources. Stakeholders asked the NYISO to consider alternative assumptions that might have produced different numerical results. The requested sensitivity analyses ultimately confirmed the initial Market Study results.

Study outcomes are provided in more detail in Appendix B: Detailed Study Results & Discussion.

17 NYISO presentations regarding the capacity study are as follows:

Project scope and proposed assumptions, June 1, 2017 ICAPWG meeting; presentation available at: <http://www.nyiso.com/public/webdocs/markets_operations/committees/bic_icapwg/meeting_materials/2017-06-01/6-1-17_IPP-ICAP-scope%20FOR%20POSTING.pdf>.

Preliminary results, July 13, 2017 ICAPWG meeting; presentation available at: <http://www.nyiso.com/public/webdocs/markets_operations/committees/bic_icapwg/meeting_materials/2017-07-13/7-13-17_IPP-ICAP-prelim-results.pdf>.

Final results and sensitivity analysis, August 22, 2017 ICAPWG meeting; presentation available at: <http://www.nyiso.com/public/webdocs/markets_operations/committees/bic_icapwg/meeting_materials/2017-08-22/agenda%204%20IPP-ICAP-final-results.pdf>.

Market Design Concepts

This section introduces ideas that could help address the concerns identified in the Market Study. The NYISO is evaluating product changes and rule changes that could incent availability, dispatchability, predictability, and flexibility. The NYISO will discuss the topics described below with stakeholders before presenting market design recommendations.

Transmission

The CES Order calls for the development of a State Resource Plan to consider measures like the construction of bulk electric transmission. Renewable curtailments observed in the NYISO's Market Study support the continued exploration of additional transmission.[18] The environmental advantages of additional renewable generation will not be fully recognized if the transmission system cannot deliver MWs from renewable resources to load centers. This dilemma is especially pertinent in New York, where renewable resources locate in the western and northern parts of the State due to favorable land for siting and favorable wind patterns, but existing transmission infrastructure limits energy delivery to load centers in NYC and Long Island.

Transmission expansion could also help displace some of the State's oldest and highest-emitting fossil units with newer, more efficient units located outside of the highly constrained transmission areas in the State.

Energy Market Design Concepts

Flexible Ramping (Forecast Uncertainty) Product

Currently, generation ramp is provided via the NYISO's look ahead processes. Market software considers the load forecast and resource ramp rates, taking actions to pre-position units to meet the forecasted load. Such actions may include changes in five-minute dispatch instructions, and commitment or de-commitment of units. Separately, generators scheduled for Regulation Service provide additional ramp within the five-minute intervals to manage second to second power balance and frequency deviations as well as short-term forecast errors.

A generation ramp product that considers conditions 30 minutes or an hour ahead could hold a portion of wholesale generating capability aside to prepare for sharp, un-forecasted swings in load ramp net of renewable resource generation, like those observed in the July RTM Market Study (Figure 55). A

[18] Appendix B - Renewable Curtailments in the Real-Time Energy Market Study

ramp product could offer a means to deal with load forecast uncertainty in real-time beyond the 5-minute timeframe, aside from quick escalations of load or lapses in renewable resource generation at certain periods of the day. Other ISOs/RTOs, including the California Independent System Operator (CAISO) and the Midcontinent Independent System Operator (MISO), have introduced generation ramp products.

The simulation did not quantify variability in the NYISO's load forecast under "50-by-30". While adequate ramp-up and ramp-down capability existed in the RTM Market Study, there may not be enough ramp capability in the future if the forecasted peak load were to occur at a different time. Further analysis of load forecast error is needed to evaluate the impact of "50-by-30" on the variability of the NYISO's load forecast.

Down Ramp Product

When accounting for the ramp-down capability of renewable resources, adequate ramp-up and ramp-down existed in the RTM Market Study cases to meet the load ramp net of renewable resource generation, see Figure 100 and the discussion on Ramp Capability of Flexible Generators. The NYISO is currently able to curtail wind resources during periods of overproduction (i.e., dispatch the units down), and will soon have similar capabilities for solar resources.[19] Dispatchability of wind and solar resources helps maintain reliable operation of a decarbonized grid; however, this type of curtailment may make it more difficult to achieve the State's de-carbonization goals. Therefore, establishing a downward ramp capability product for other resources may warrant additional review and discussion.

Operating Reserve and Regulation Service Shortage Pricing

Shortage pricing helps the NYISO manage load uncertainty, net of intermittent renewables, by incenting market participants to offer more flexibility and responsiveness in real-time. Current shortage pricing rules and the relative value between existing products could be re-evaluated as certain attributes become more important. Any new product must have high enough shortage pricing to incent performance in real-time, while respecting the relative value compared to other products.

Real-Time Operating Reserve Offer Cost Rules

Allowing non-zero Operating Reserve offers in real-time could also provide a better price signal to flexible units to stay online to help manage net load forecast uncertainty.

Constraint Specific Transmission Shortage Pricing

The NYISO currently uses a graduated transmission constraint pricing mechanism to set prices during

[19] Grid-scale solar participation requirements are currently being discussed with NYISO stakeholders. The requirements will likely be consistent with established rules for wind resources.

certain transmission shortages. However, some transmission shortages are still resolved by relaxation instead of by setting prices through a graduated transmission constraint pricing mechanism. In 2018, the NYISO intends to study replacing the current transmission constraint pricing methodology with multiple transmission demand curves that can vary according to the importance, severity, and/or duration of the transmission constraint violation. As part of the study, the NYISO will consider discontinuing or limiting the use of transmission constraint relaxation. This would allow price signals to form that are important for investment in and reliable operation of Incremental Renewable resources.

Offline Fixed Block Pricing

At times, offline fast-start Fixed Block Units are eligible to set prices without being physically committed. This sets a realistic administrative price that approximates the actual marginal cost of the next megawatt needed to serve load, but in the future could prevent the realization of shortage prices providing higher price signals that reflect NY Power System supply needs. Future revisions to offline fast-start pricing could be considered to review whether price signals accurately reflect the severity of supply shortage conditions and that sufficient resources are physically available to manage grid volatility.

Operating Reserve Procurement

Shortage pricing provides a price signal consistent with operating conditions that draws attention to NY power system constraints and rewards resources that resolve constraints. Shortage pricing reflects the relative value of different reserve products, transmission, and Regulation service. For example, a price spike in the March RTM Market Study case (Figure 47[20]) signaled that additional resources were needed to serve an evening load increase. Incremental renewables, added as part of "50-by-30", may increase pricing volatility, and may necessitate revisions to the NYISO's shortage pricing methodology. One approach could be to procure Operating Reserves beyond the minimum requirements at lower price points to reflect both the incremental value that one MW above the Reserve requirement provides, similar to the construction of the ICAP demand curve, and signal constrained NY Power System conditions sooner and more gradually.

Operating Reserve Areas and Minimum Requirement

The NYISO uses market processes to satisfy reliability requirements, such as procurement of 10-minute synchronous, 10-minute non-synchronous, and 30-minute Operating Reserve products. These products fulfill various reliability rules; for example, the amount of 10-minute total (synchronous and non-synchronous) Operating Reserve procured in the NYCA is equal to the most severe contingency under normal transfer conditions, *i.e.*, the loss of the largest generating resource in the State. The NYISO is

[20] Appendix B: Detailed Study Results & Discussion, Real-Time Market Prices, March 22, 2016

generally able to recover quickly from other contingency scenarios, such as line outages because it procures locational reserves. Under "50-by-30", the basis for these operating procedures should be reviewed to determine whether the most severe contingency should be redefined. For example, rather than the loss of one large generator, the largest contingency of the future grid could be sudden cloud cover reducing solar output 20%. Further review of Operating Reserves should include the locational requirements of Operating Reserves, and necessary products that Operating Reserves cover.

Higher shortage prices for Operating Reserves and Regulation in particular would increase availability of these products to the grid. Reserve availability may be especially important to hedge against intermittent renewable contingencies.

Dynamic Procurement of Operating Reserves

In the future, Operating Reserves could be procured dynamically based on the changing available transmission capability. This will be more important in the future as transmission flows could change rapidly due to shifting renewable resource output. Allowing the Day-Ahead Market and Real-Time Market software to schedule Operating Reserves while ensuring there is available transmission capability to deliver Operating Reserves will maintain grid reliability after a severe contingency occurs, while minimizing costs to load.

Operating Reserve Performance

In the *2016 State of the Market Report for the New York ISO Markets*,[21] Potomac Economics recommended that the NYISO "consider means to allow reserve market compensation to reflect actual and/or expected performance." Today, generator's offering reserve services have limited financial exposure if unable to convert to energy when called upon. Incentives for operating reserve providers to perform when called should be discussed further as more renewable resources come online.

Regulation Capacity

Regulation Service helps the NYISO maintain NY Power System frequency, and is procured to meet the necessary load ramp within a five-minute real-time interval.[22] High Regulation prices in the Market Study cases[23] suggest that the NYISO's ability to maintain NY Power System frequency could be compromised if additional grid flexibility is not incentivized. The NYISO expects to revisit Regulation Capacity

21 The 2016 State of the Market Report for the New York ISO Markets can be found at this link: http://www.nyiso.com/public/webdocs/markets_operations/documents/Studies_and_Reports/Reports/Market_Monitoring_Unit_Reports/2016/NYISO_2016_SOM_Report_5-10-2017.pdf

22 NYISO Regulation Requirements are posted on the NYISO website: http://www.nyiso.com/public/webdocs/market_data/reports_info/nyiso_regulation_req_sum04.pdf.

23 Appendix B: Detailed Study Results & Discussion, Ancillary Services

requirements to incent additional grid flexibility and minimize shortages as intermittent renewable penetration increases.

Separating Regulation Up and Regulation Down

There may be some value in separating the current Regulation Service product into two products: regulation-up and regulation-down. This would liberate some of the operating capacity of regulating resources by enabling them to provide either one product or the other. For example, a combined-cycle plant sitting at its minimum generation point could provide regulation-up, and a wind turbine producing energy at its maximum output could provide regulation-down. Today, neither would be able to provide Regulation at those operating points.

Regulation Movement

The NYISO's Regulation Service product is comprised of two components: Regulation Capacity and Regulation Movement. The Regulation Capacity price includes the impacts of shortage pricing when the Regulation Capacity requirement is not met. The bid of the last dispatched resource is used to set the Regulation Movement price. To incent an appropriate amount of movement in a future with significantly more renewable resources, it may be necessary to rethink the optimization of Regulation Movement and to set the Regulation Movement price by a demand curve during times of shortage.

Cycling Product

In the Market Study, increased load variability over short time frames caused the market software to commit and de-commit (cycle) existing generators more often than it does today[24]. Cycling units were turned on and off repeatedly to manage the forecast uncertainty caused by fluctuations in output from intermittent renewables.

Units like steam and gas turbines incur maintenance and startup costs each time they cycle, and some equipment degrades in direct proportion to how frequently it cycles. Generally, the energy market optimization commits resources in a manner that allows resources to recover these costs. However, energy market clearing prices may not incent generators to continue to provide flexibility since they may only be recovering their costs through a bid production cost guarantee payment instead of energy clearing prices. Flexible generators may retire or stop offering cycling flexibility if they cannot earn sufficient revenues from Energy market clearing prices. It may be necessary to develop additional products to value this service to attract and retain resources in sufficient quantity to meet future needs.

[24] Appendix B: Detailed Study Results & Discussion, Energy Market Study Results, Generator Cycling

Revisions to LBMP-Based Penalties when LBMPs are Negative

Negative LBMPs may be a frequent occurrence in a future with significantly more renewable generators. For example, negative prices occurred in both the Day-Ahead and real-time periods of the March Market Study day, see Figure 59 and Figure 60. Resources under-generating that have to buy out at negative LBMPs are arguably not incented to follow dispatch. Under-generation during periods of high negative LBMPs may help to balance supply and demand in the NY Power System in some instances, but resources should be incented to follow dispatch instructions from the NYISO at all times to maintain grid reliability.

Inertia, Primary Frequency Response, and Voltage Support

Maintaining the 60 Hz frequency of the grid is of paramount importance to the NYISO. Today, inertia provided by the rotation of synchronous generators absorbs frequency fluctuations, helping to maintain grid stability. Inverters used by renewable generators may also be able to offer primary frequency response. In a recent NOPR,[25] FERC asked for comments on its proposal to require all generators to provide primary frequency response. Such a rule would help grid operators continue to maintain the required frequency.

Although the NYISO's primary frequency response contribution for an Eastern Interconnection event is small today, reliability needs may cause it to increase in the future. New market products that value primary frequency response and voltage support could incent more market participants to offer these services. Any such market products should provide a technology neutral mechanism to satisfy the reliability need. For example, the NYISO currently compensates voltage support through a rate-based compensation structure. As a future with high intermittent renewable penetration approaches, there may be a need to differentiate voltage support by the speed with which it can be delivered, *i.e.*, to value voltage quickly delivered to stabilize the NY Power System differently from voltage supplied to meet less urgent power system needs.

Analysis of inertia, primary frequency response, and voltage support needs was beyond the scope of the Market Study. An assessment of these attributes in a hypothetical "50-by-30" scenario is needed to appropriately assess whether pricing new market products would enhance grid reliability.

Transaction Scheduling

The NYISO sets a Desired Net Interchange (DNI) ramp limit with neighboring regions by considering how much ramp NYISO expects to be available to meet transaction schedules. DNI ramp is the change in

[25] FERC Docket No. RM16-6

import or export MW achievable within 10 minutes, which the NYISO agrees to with each neighboring Control Area. Absent a rule change or new product, the real-time load ramp volatility[26] observed in the Market Study may necessitate review of the NYISO's DNI ramp limit, *i.e.*, modifying the change in interchange that can be scheduled from one interval to the next. More frequent transaction scheduling could help the NYISO manage real-time uncertainty and avoid negative impacts on the DNI by providing for increased supply flexibility and allowing transaction schedules to change more frequently than once every 15 minutes or once every hour. It would also improve the flexibility of the NY Power System and may benefit neighboring control areas, many of whom also look to a future with more renewable resources.

Schedule Energy, Reserves, and Regulation on a 15-Minute Basis in the DAM

The DAM currently procures energy, Operating Reserves, and Regulation at an hourly level. Resources may have their real-time schedules deviate from Day-Ahead schedules if RTC identifies a more efficient option. Scheduling the DAM on a more granular basis, such as 15-minutes, may improve the efficiency of the Day-Ahead commitment of resources when intermittent renewable schedules are constantly changing in real-time. This type of change may also allow for more efficient virtual trading and scheduling of energy storage resources with lower MWh output capability. Studying the accuracy of more granular Day-Ahead forecasts will help inform the viability of this type of change.

Other Stakeholder Energy Market Design Concepts

The NYISO has encouraged its stakeholders to share energy market design concepts at working group meetings. Many of the market design concepts mentioned in this report were submitted by NYISO stakeholders. While this report may not discuss all stakeholder feedback to date, the NYISO will continue to discuss potential market rule changes and product enhancements that prepare the wholesale energy markets to accommodate the entry of large amounts of renewable resources at future stakeholder working group meetings.

26 Appendix B: Detailed Study Results & Discussion, Real-Time Net Load Forecast Uncertainty

Capacity Market Rule Changes

The NYISO, with input from its stakeholders, has identified market rule concepts that might enhance capacity market efficiency, and open design questions that could be considered further, as additional renewable resources enter the market. Appropriate capacity market design changes could help harmonize the three goals of administering efficient markets, operating the NY Power System reliably, and providing the opportunity for public policy goals to be achieved. The study's analysis suggests further consideration of three aspects of the capacity market in relation to an increase of renewable resources in the market: capacity eligibility requirements, obligations for capacity resources, and the means of measuring capacity suppliers' performance. Further evaluation will seek to ensure that the increase in renewable resources will be harmonious with these parameters, and will continue to allow the capacity market to achieve its goal of attracting and retaining the resources required for resource adequacy.

Capacity Eligibility Requirements

Currently the requirement for resources to be eligible for the capacity market is based on a minimum output of 4-hours. The NYISO is currently appraising the relative values of different output durations as part of the DER Participation Model. That initiative will provide insights into how different eligibility requirements would influence resource adequacy and evaluate the relationship between capacity value and the output duration

Whether the current eligibility requirement is affirmed as sufficient or is enhanced based upon a new understanding, the NYISO will continue to provide a clear definition of capacity and ensure that the capacity requirements sufficiently ensures resource adequacy. Any changes to capacity eligibility requirements should also ensure that capacity suppliers are adequately compensated for the true value of the reliability they provide.

Obligations of Capacity Resources

In order to ensure that they are available when needed to maintain reliability, with limited exceptions, capacity resources are required to bid energy in the Day-Ahead Market, schedule an a NYISO-approved outage, or notify the NYISO of an unplanned outage. The Capacity Market Study and the NYISO's Performance Assurance project have identified this rule as one that should be reviewed. Other ISO/RTO's have recently revised their rules to mandated stricter supplier performance requirements. An analysis for the NYISO's market would inform the NYISO and its stakeholders regarding the merits and value of revising this rule.

The exception to the rule is available to Intermittent Power Resources, including renewables like wind and solar. The NYISO's evaluation of the rule should consider whether future capacity supplier requirements should be technology neutral. As part of the constantly evolving market, it may be necessary to introduce new obligations on capacity resources that can help the NYISO operate the NY Power System reliably.

Capacity Performance Measurement

The NYISO currently uses several methods to audit the performance of capacity resources and establish maximum participation levels. An Equivalent Demand Forced Outage Rate ("EFORd ") construct measures the performance of dispatchable generators. Output during certain peak demand periods measures the performance of Intermittent Power Resources and Limited Control Run-of-River Hydro Resources.[27] Load reductions during demand response events measures the performance of Special Case Resource program participants. The approaches to measuring actual performance should be considered in relation to appropriate compensation.

The performance assessment of intermittent renewables during specific hours is designed to identify their expected availability during historic periods of peak annual demand,[28] and modeled 'loss of load events'. The value of intermittent renewables, as with other resources, depends on their ability to meet load during periods of NY Power System stress.[29] NY Power System stress has historically been correlated with peak load periods, but could change as the electricity grid evolves. The DER Participation Model effort previously mentioned also seeks to understand how the value of capacity may change as peak load periods change in the future. For example, it may not be optimal to measure a capacity resource based on its performance between hour beginning fourteen (14) and hour beginning eighteen (18) if the daily net load peak occurs between hour beginning eight (8) and hour beginning ten (10). The NYISO is actively considering mechanisms by which to adjust the performance measurement as NY Power System needs change. For example, if the peak load shifts from the 2PM-6PM period as a result of resources that modify load (such as behind the meter solar,) it may be appropriate to have a mechanism to adjust the performance measurements of intermittent renewables to reflect the value they provide when they are most needed.

An EFORd measures the performance of resources throughout the entire year. This practice may not correlate to whether the resource is available when it is not needed versus when it is likely to be needed. It

[27] *See, e.g.*, NYISO ICAP Manual, Section 4.5.

[28] NYISO 2017 Gold Book, Table I-4d: "Historical NYCA System Peak Demand".

[29] There are numerous potential methods that could be used to identify 'stressed' system conditions. Reserve shortages in the energy market and modeled loss-of-load events in the NYISO capacity requirement setting processes (*i.e.*, MARS simulations) are two such methods.

may be appropriate to consider weighting the EFORd mechanism more heavily during periods in which the NY Power System may be stressed (*e.g.,* peak summer months.)

Finally, further evaluation of a differentiated performance measurement (*i.e.*, different measurements for intermittent renewables and fossil fueled resources) rather than a technology neutral construct might be appropriate.

Potential Topics for Future Evaluation

The Capacity Market Study identified ICAP market rules that, if enhanced, may foster ensuring resource adequacy.

Performance Factors for New Entrant Renewable Resources

The NYISO ICAP Manual establishes performance factors for several classes of renewable resources when they enter the market, such as on-shore wind, offshore wind, and solar photovoltaic resources. These pre-set performance factors remain in place until actual performance data becomes available, and affect capacity market compensation for these resources for approximately their first year of operations. Since these performance factors have an impact on capacity market parameters (*i.e.,* ICAP requirements) and also the resources' compensation, these parameters should be reviewed and considered for revision.

Behind-the-Meter vs. Front-of-the-Meter Impacts on the Capacity Market

Because the Final EIS presumes that 5000 GWh/y of behind the meter solar will contribute to the achievement of the "50-by-30" goal, it is important to understand the relative implications of resources being located behind versus in-front of the meter. Utilizing the behind the meter solar as an example, the Market Study indicates their different relative effects on the market. The NYISO should continue to study the effects on the market of an increasing amount of intermittent renewables may be located behind the meter and offset load, and evaluate the potential for the increases' impact and whether it should be addressed.

Determination of Capacity Requirements in an Evolving Bulk Electric System

The IRM (as utilized in the NYISO's market through its conversion to the NYCA Minimum Installed Capacity Requirement) and LCRs directly affect capacity prices and investment signals. The Market Study estimated the effect of additional renewable resources on these parameters with a simplified first-order model.

As additional renewable resources enter the market, if they are capacity resources, their effects on both the IRM and LCRs will be determined. The NYISO should periodically evaluate the impact of renewables on capacity requirements. In order to do so, it may be necessary to review and update the modeling techniques used to incorporate them into the resource adequacy model.

Forward Capacity Market

Certain stakeholders have provided feedback to the NYISO that a forward capacity market (FCM) could be beneficial in assisting with the accommodation of State energy policy and the transition of an aging fleet. On several prior occasions, most recently in 2015, the NYISO and its consultant, with input from stakeholders, previously evaluated the need for an FCM and concluded that it was not warranted.[30] Some stakeholders recently suggested that previous NYISO studies were not conducted in the context of accommodating public policies, and that the NYISO could reevaluate the need for an FCM within this context, pointing out that neighboring control areas such as PJM and ISO-NE have utilized bifurcated FCMs to assist in accommodating public policy.[31] Any reevaluation should not preclude or serve as replacement of the previous topics discussed, and would need to be conducted in conjunction with the other areas of market design previously mentioned.

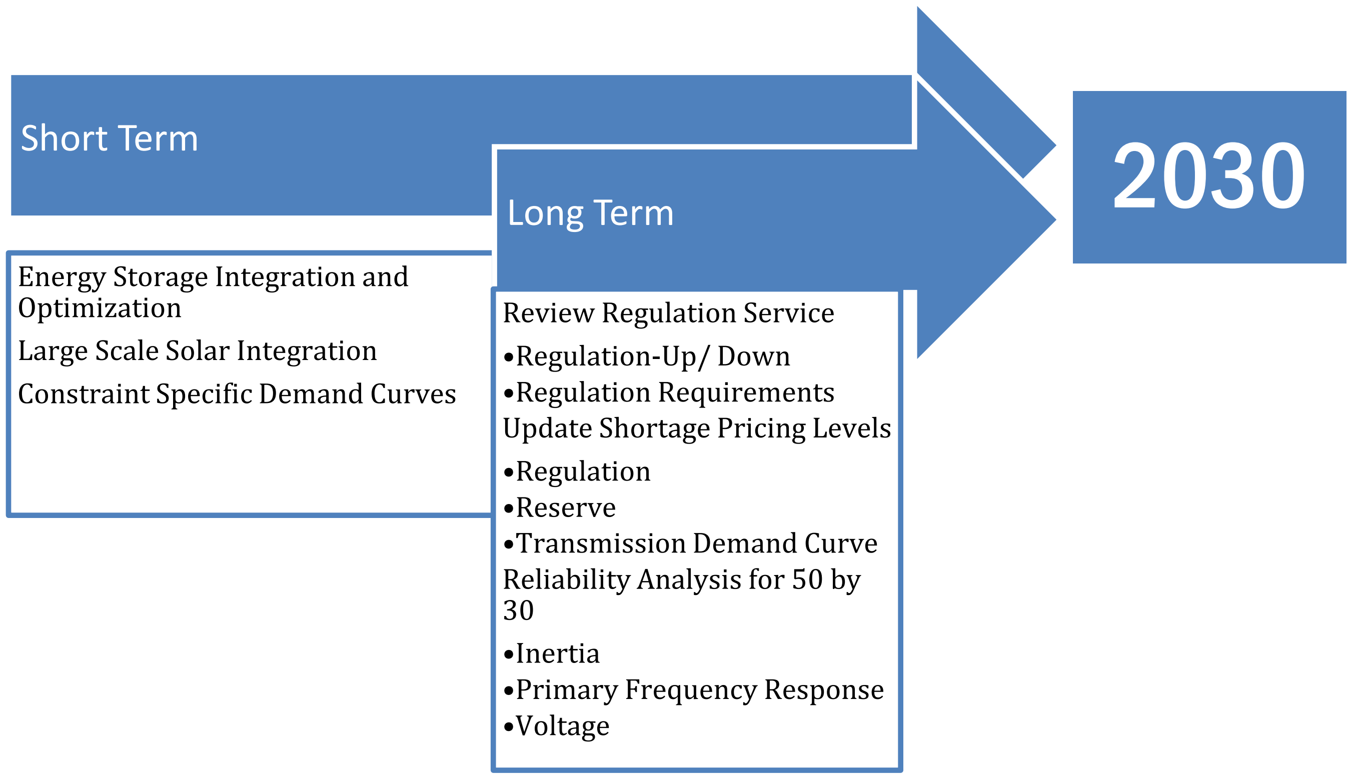
Conclusion and Next Steps

As 2030 approaches, the NYISO will work with its stakeholders to identify promising energy market and capacity market design changes. The NYISO will consider studying how the changes described in this report could affect NY Power System needs for inertia, primary frequency response, and voltage. In 2018, NYISO staff will carefully review the concepts discussed in this report to determine which concepts are most likely to incent the characteristics needed to maintain the reliability of the NY Power System. During this process, the NYISO will review the best practices from other ISO/RTO's, advice from industry experts, feedback from stakeholders, and conduct further analysis using NYISO's market software. The most viable ideas will be recommended as future market design projects.

30 NYISO Capacity Market: Evaluation of Options, Analysis Group, (May, 2015), available at: <http://www.nyiso.com/public/webdocs/markets_operations/committees/bic_icapwg/meeting_materials/2015-02-25/AG%20Capacity%20Market%20PDF.PDF>.; NYISO Management Response to Analysis Group Report, available at: <http://www.nyiso.com/public/webdocs/markets_operations/committees/bic_icapwg/meeting_materials/2015-02-25/NYISO%20Management%20Response%20to%20Analysis%20Group%20Report%202015.pdf>.

31 See Independent Power Producers of New York, Comments on Integrating Public Policy, Nov. 8, 2017, available at: <IPPNY, http://www.nyiso.com/public/webdocs/markets_operations/committees/bic_miwg/meeting_materials/2017-11-02/IPPNY%20Comments%20on%20Integrating%20Public%20Policy.pdf>; NRG, NYISO: Integrating Public Policy, <http://www.nyiso.com/public/webdocs/markets_operations/committees/bic_miwg/meeting_materials/2017-11-02/NYISO%20NRG%20presentation_IPP.pdf>.

Figure 20: Next Steps for the Energy Market Looking Forward to 2030



In parallel, some of the efforts discussed in this report are currently ongoing or have been project candidates before the Budget Priorities Working Group (BPWG) at the NYISO. Constraint Specific Demand Curves and Large Scale Solar Integration are approved project for 2018.

Appendix A: Study Methodology

NYISO Markets

Wholesale Energy Markets

The NYISO uses an optimization algorithm to schedule generators to provide energy, reserves and frequency regulation. The Day-Ahead bid-based Security-Constrained Unit Commitment (SCUC), Real-Time Commitment and Real-Time Dispatch software programs seek the lowest cost solution to balance generation and load across the NYCA. Market optimizations run on several different time horizons. The Day-Ahead Market (DAM) develops schedules over the 24-hour Dispatch Day. The Real-Time Market (RTM) is comprised of Real-Time Commitment (RTC), which runs every 15 minutes, and a Real-Time Dispatch (RTD), which nominally runs every 5 minutes.

SCUC, RTC and RTD calculations consider Market Participants' financial offers, generator operating parameters, forecast load, transmission system transfer capability, short-term fluctuations in demand, and contingencies like unplanned generator and transmission outages. The NYISO monitors bidding behavior to mitigate the market effects of any conduct that would substantially distort competitive outcomes in the NYISO-administered wholesale electric markets.

The NYISO administers the DAM to schedule the least-cost unit commitment and dispatch for the following day based on supply (generation) and demand (load) bids. The DAM is a financial market that permits non-physical bids of Virtual Supply and Virtual Demand. Virtual bids help drive convergence between Day-Ahead and real-time solutions because they represent rational expectations of how real-time conditions may differ from Day-Ahead forecasts.

The initial inputs to the Real-Time Market optimization are the schedules generated by the DAM, hourly bids from suppliers, and the real-time load forecast. The RTC co-optimizes to solve simultaneously for Load, Operating Reserves and Regulation Service on a least as-bid production cost basis over a two hour and fifteen-minute optimization period. The optimization evaluates the next ten points in time separated by fifteen- minute intervals. The RTC result is then passed to the Real-time Dispatch (RTD) tool, which looks one-hour ahead to solve simultaneously for Load, Operating Reserves and Regulation Service on a least as-bid production cost basis in 5-minute intervals. RTD is a dispatch-only engine that does not commit resources. Only the first RTD interval is binding for settlement purposes. RTD sends generators advisory signals for the rest of the hour.

Capacity Market

The NYISO operates a capacity market to competitively procure the capacity required to meet NYCA resource adequacy targets established as an Installed Reserve Margin set by the New York State Reliability Council, and then converted by the NYISO to a NYCA Minimum Installed Capacity Requirement, and the NYISO-established LCRs. The NYISO ICAP market, in conjunction with revenues from the Energy and Ancillary Services markets, is designed to attract and retain the resources necessary to ensure resource adequacy. Through the automated auction, loads purchase any capacity offered by suppliers that clears on the relevant capacity market Demand Curve. Thus, capacity suppliers receive revenues as a function of both; (1) market parameters (*e.g.*, the Demand Curve), and (2) current capacity levels (supply). Capacity suppliers are then obligated to offer their capacity into the Day-Ahead energy market, which ensures sufficient resources are available each day to meet reliability criteria.[32]

Energy Market Study Methodology

Approach

The objective of this study was to gauge how New York State's "50-by-30" goal could impact the NYISO's existing wholesale electricity markets. An offline instance of the NYISO's market software was used to explore the impact that presumed renewables might have on both DAM and RTM outcomes. One 2016 day representative of each season (spring, summer, winter, and fall) was selected for analysis. The term "Market Study" refers to solutions developed for hypothetical scenarios on those days. Solutions generated using the NYCA's 2016 generation mix were used as a basis for comparison and are referred to throughout this report as the "Production Baseline". A full unit commitment and dispatch was executed for each scenario, meaning that generators were only selected to provide services offered at the lowest as-bid cost that could meet NY Power System needs.

The NYISO did not forecast retirements or transmission changes. Market Study cases were provided with the same fundamental constraints as the corresponding Production Baseline cases. Existing (2016) generators were assumed to have the same availability on Market Study days as they did on Production Baseline days. Weather conditions, fuel costs, bid parameters and marginal costs by extension were also unchanged. External transactions, other than transactions with Hydro Quebec (HQ), were held constant to simplify calculations and to avoid having to make assumptions about neighboring control areas. The

[32] With limited exception, resources that have sold into the capacity market for the month are obligated to bid in the Day-Ahead Market, self-schedule energy, or notify the NYISO of an unplanned outage. *See* Section 5.12.7 of the NYISO Market Administration and Control Area Services Tariff.

addition of renewable generators was the only significant change made for Market Study cases. The renewable generator additions are described later in this Appendix[33]. Figure 21 specifies which variables were held constant and which variables changed between the Production Baseline cases and Market Study scenarios.

Figure 21: Summary of Variables Held Constant or Changed for Energy Market Study

Market Study Parameter	Comparison to Related 2016 Production Baseline	
	Constant	Changed
Market Offer (Bids)	X	
Weather Forecast	X	
Load Forecast	X	
Real Time Power System Conditions	X	
Transmission Outages	X	
Generator Outages	X	
Generator Availability	X	
Transmission System	X	
External Transactions	All Except HQ Chateauguay	HQ Chateauguay
Fuel Costs	X	
Renewable Resource Nameplate Capacity		X

A complete offline simulation was performed for all four real-time Market Study cases. The Production Baseline cases used real-time production data from the selected 2016 days. To create Production Baseline scenarios, the historical study days were first re-run using the current version of NYISO's market software in offline mode. The NYISO runs its simulations on a non-production system and baselining the original case ensures that comparisons between cases can be done accurately. As a general practice, the NYISO will baseline its study cases when possible.

Figure 22 identifies the origin of the data used or analyzed in this report. All cases utilized actual operating parameters and market rules from 2016.

Figure 22. Sources of Data Used for Energy Market Simulations

Case	Power System Conditions	Market Run	Number of Scenarios	How Market Solution Data Was Obtained
Production	2016 Actual	Day Ahead	4	Simulated using Offline NYISO
Market Study	2016 Actual	Day Ahead	4	Simulated using Offline NYISO
Production	2016 Actual	Real Time	4	NYISO Production Data
Market Study	2016 Actual	Real Time	4	Simulated using Offline NYISO

[33] CES Order Appendix A: Study Methodology, Renewable Energy Targets

Assumptions

2016 Days Selected for Study

The summer and winter days selected were days with high peak loads, while the spring and fall days were typical low load shoulder days. The January day was the winter peak load day and was characterized by significant transmission outages in the West. Indian Point 2, a large nuclear generator located just north of New York City, was offline for refueling during the March day. The July day had severe thunderstorms pass through the State from West to Southeast during peak load hours. On the November day, winds were significantly higher than usual, driving a high capacity factor for wind resources. Figure 23 summarizes other key characteristics.

Figure 23: Days Selected for Market Study

Study Day	Peak Load Forecast (MW)	Peak Load Hour	High-Low Temp. ALB/LGA*	Gas Prices TNZ6/TZ6NY**	Other
Tuesday, January 19, 2016	22,168	18:00	23-13/29-18	$4.20/$6.25	Winter Peak
Tuesday, March 22, 2016	18,638	20:00	51-27/55-35	$2.02/$1.30	IP2 Refueling***
Monday, July 25, 2016	31,401	16:00	89-68/91-81	$2.91/$2.83	High Load
Thursday, November 10, 2016	19,131	17:00	51-31/57-43	$2.45/$1.90	High Wind

*High and Low temperatures were recorded at Albany International Airport (ALB) and LaGuardia International Airport (LGA).

**TNZ6 prices apply to zones F-I, while TZ6NY prices apply to zones J-K.

***Indian Point 2 is a large (~1,000 MW) nuclear generator located in zone H. It was offline for refueling on March 22, 2016.

Time Horizon for Real-Time Market Study

Market Study solutions are provided for RTM intervals between 00:30 and 21:40. The NYISO's real-time software relies on information from the prior day to develop the commitment and dispatch instructions for 00:00 to 00:30 and information about the next day to develop the commitment and dispatch instructions for 21:40 to 23:55. The Market Study days were single-day studies; therefore, no information was available to the NYISO's offline software about the prior or future days.

Production Baseline (2016) Power System Components

In 2016, approximately 25% of New York's electricity was produced by renewable resources.[34] Renewable resources in the NYCA today include large and small hydroelectric facilities, wind farms and utility-scale solar. Non-renewable resources include nuclear and combined cycle power plants, combustion turbines and jet engines. Most of the large renewable resources and nuclear generators are located in the

34 Power Trends, New York's Evolving Electric Grid, 2017: https://www.nyiso.com/public/webdocs/media_room/publications_presentations/Power_Trends/Power_Trends/2017_Power_Trends.pdf

North and West areas of the State, whereas thermal generation dominates the South and East portions of the State. The majority of the electric load is also located in the Southeastern portions of the State.

Figure 24: 2016 Renewable Resources by Zone [MW], (NYISO 2016)

Resource	Load Zone										
	A	B	C	D	E	F	G	H	I	J	K
Wind	136	7	569	601	442						
Utility-scale Solar											32
Hydroelectric	2,865	65	132	1,163	492	502	107				
Biomass	56				92						
Landfill Gas	29	16	50	6	11	14	6				6
BTM Solar	38	23	56	2	34	113	114	18	23	82	209

The CES Order based the existing generation mix on the NYISO 2015 Load & Capacity Data Report ("Gold Book")[35], which represents 2014 generation. The NYISO Market Study used 2016 operating data with the assumed existing resource mix resembling the generation in the 2016 Gold Book, with the addition of customer-sited behind-the-meter solar, which was estimated using data provided by NYSERDA. Most behind the meter solar in New York is tracked by NYSERDA as part of its NY-Sun program.[36] For the Market Study, existing behind the meter solar resources are removed from the total new behind the meter solar that is assumed in the CES Order.

Offer Parameters for Existing Resources in Market Study Cases

The actual offers from existing units were used in the Production Baseline cases and the corresponding Market Study cases, with two exceptions. First, a scaling factor was used to adjust the bids of large hydroelectric generators according to their lost-opportunity costs. Second, the operating constraints imposed by some self-committed generators were relaxed to drive more convergence between real-time bids and Day-Ahead schedules.

For resources that rely on purchased-fuel to generate electricity, the Market Study assumed that fuel costs and the corresponding generator offers were unchanged. Some existing resources have no fuel costs, but can control output. These resources frequently submit incremental energy bids according to their expectations of LBMPs, to produce schedules that correspond to higher LBMPs. This class is referred to as "Opportunity Cost Bidders" because their bids are based on expectations of prices, rather than actual

35 2015 Load and Capacity Data can be found here: http://www.nyiso.com/public/webdocs/markets_operations/services/planning/Documents_and_Resources/Planning_Data_and_Reference_Docs/Data_and_Reference_Docs/2015%20Load%20%20Capacity%20Data%20Report_Revised.pdf

36 Solar Electric Programs Reported by NYSERDA: Beginning 2000 can be found here: https://data.ny.gov/Energy-Environment/Solar-Electric-Programs-Reported-by-NYSERDA-Beginn/3x8r-34rs

operational costs. For the simulations to produce rational results, the offers from certain resources had to be scaled in proportion to the drop in prices caused by the large addition of low marginal-cost resources.

To maintain the relative bid profiles, the Market Study bids for each supplier that bases its offers on opportunity costs, were created by scaling their Production Baseline bids by a single, daily factor in both the Day-Ahead and real-time simulations. To create the scaling factors, simulations were first run only with the Incremental Renewable resources added (an "intermediate" run). The market clearing prices from the intermediate run were used to create the scaling factors based on the ratio of the locational LBMPs during the peak load hours in the Production Baseline divided by the LBMP during the same hour in the intermediate run. Then, final simulations were run with opportunity costs bids adjusted according to these scaling factors. The scaling factors are listed in Figure 25.

Figure 25: Bid Scaling Factors for Opportunity Cost Bidders

Market Study Day	Intial Market Study LBMP [$/MW]	Production Baseline LBMP [$/MW]	Ratio
January	$2.16	$27.64	8%
March	$2.17	$7.00	31%
July	$19.96	$69.80	29%
November	$1.21	$25.60	5%

A small number of conventional fossil fuel generators are fuel limited. As a means of managing their fuel supplies, these resources conform their real-time offers to match their Day-Ahead schedules. The real-time offers for these resources were modified to avoid following a Day-Ahead schedule based on the Production Baseline clearing prices.

Renewable Capacity Added for Energy Market Study

The NYISO relied on the Final Supplemental Environmental Impact Statement (Final EIS)[37] for guidance on the estimated quantity and location of Incremental Renewables. The Final EIS estimates needing a portfolio of new large-scale renewables totaling approximately 29,000 GWh/year of front of the meter resources and 5,000 GWh/year of behind the meter solar generation to reach the State's goals. To approximate the quantities presumed in the Final EIS, the Market Study adds 13,444 MW of renewable nameplate capacity to the 8,108 MW already existing in the NYCA. Figure 2 details where that renewable capacity was modeled, by zone. Figure 26 and Figure 27 illustrate the renewable resource mix in the Production Baseline and Market Study cases, respectively. A detailed discussion of how these quantities

37 PSC Case 15-E-0302, Proceeding on Motion of the Commission to Implement a Large-Scale Renewable Program and a Clean Energy Standard, Final Supplemental Environmental Impact Statement (May 19, 2016).

were estimated for each resource type follows.

Figure 26: Renewable Resources, Baseline Production [MW]

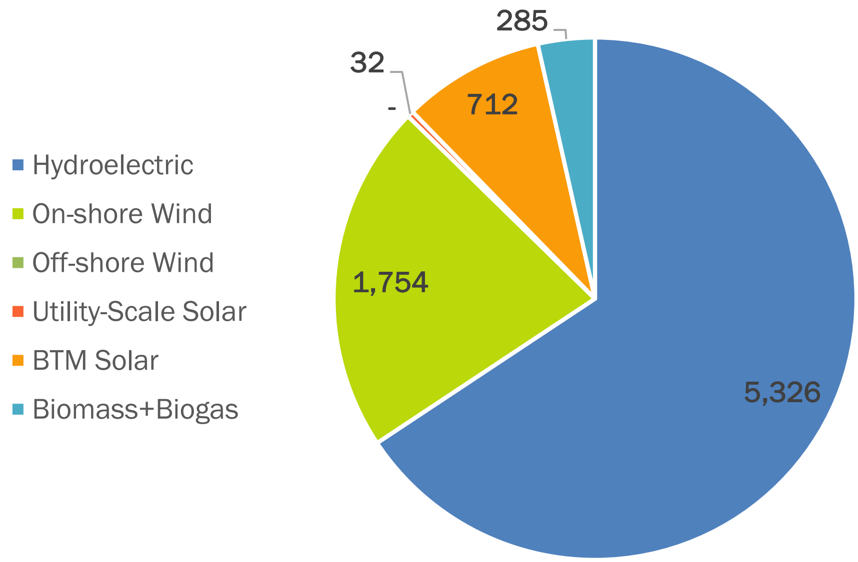
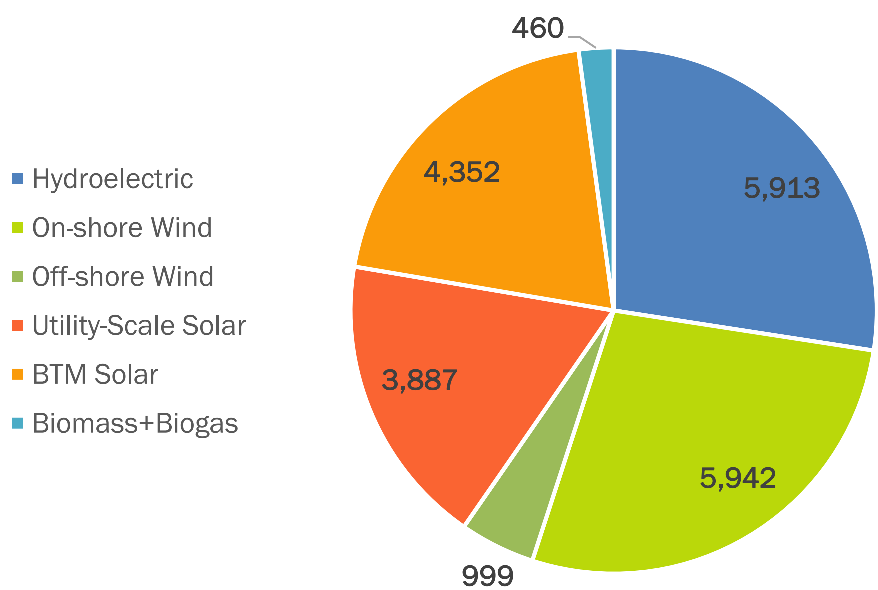


Figure 27: Renewable Resources, Market Study [MW]



The zonal distribution of these resources is summarized in Figure 28, Figure 29, and Figure 30. Front of the meter Incremental Renewables were allocated to each zone according to the estimates provided in the Final EIS, and behind the meter Incremental Renewables were allocated in direct proportion to the distribution of existing behind the meter renewable resources. Within each zone, both front of the meter and behind the meter Incremental Renewables were represented as if they were spread across each zone in direct proportion to the zonal load distribution. Complete data profiles for Incremental Renewables in the Market Study are provided in Supplemental Appendix 1.

Figure 28: Zonal Distribution of Renewable Capacity Added to NYCA Simulation for Market Study

Resource	Load Zone										
	A	B	C	D	E	F	G	H	I	J	K
Wind (On-shore)	981	238	947	851	1,031	141					
Wind (Off-shore)										408	591
Utility-Scale Solar	841		391			1,812	431	7			373
Hydroelectric	8	30	72		219	213	28	17			
Biomass	57		65								
Landfill Gas	5	4	2			2			3	34	3
Behind the Meter Solar	193	117	287	10	174	577	584	91	118	419	1,069
Total	2,085	389	1,764	861	1,424	2,745	1,043	115	121	861	2,036

Figure 29: Total Renewable Resources by Zone, Production Baseline

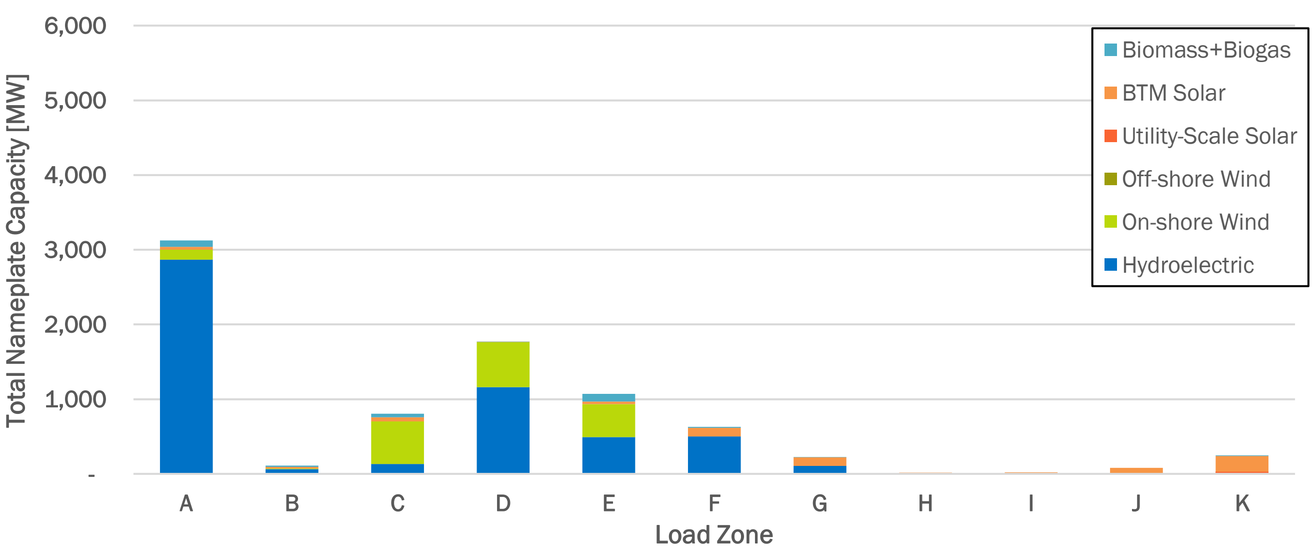
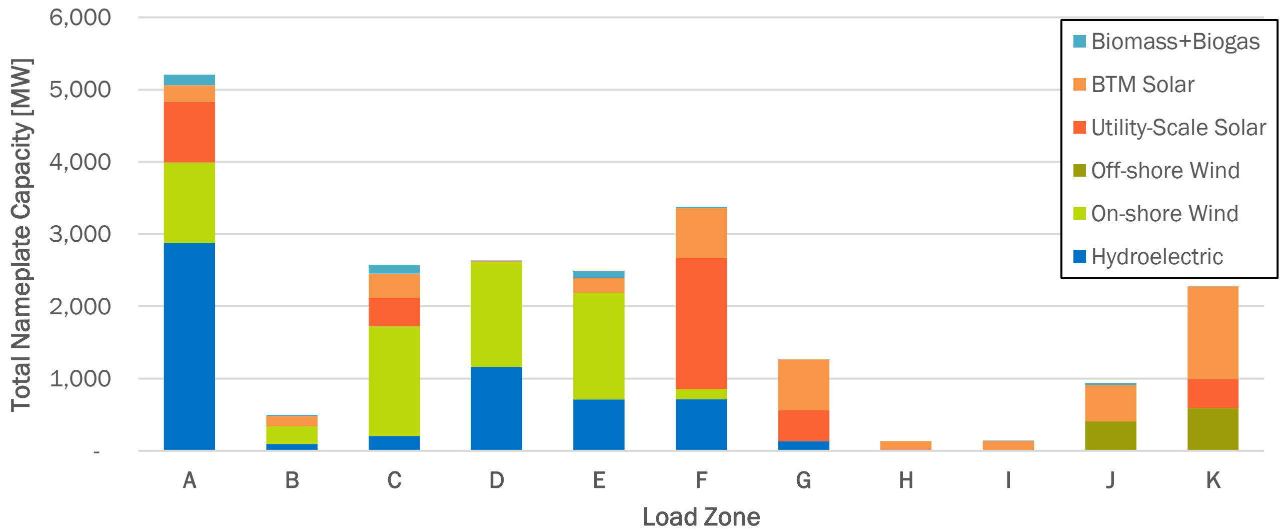


Figure 30: Total Renewable Resources by Zone, Market Study



Generation Output Profiles of Incremental Renewables

Zonal generation output profiles were created for each class of Incremental Renewables in order to model both their forecast and actual performance in the Market Study simulations. DAM Market Study Incremental Renewable generation output profiles were created using the existing Day-Ahead forecasts used for the same renewable types on the Production Baseline days. RTM Market Study Incremental Renewable generation output profiles were created using the real-time Production Baseline output. The following section details the generation output profiles that were created for each type of Incremental Renewable.

Onshore Wind Resource Profiles

In 2016, New York had 1,754 MW of grid-connected onshore wind resources. For the Market Study, 4,188 MW was added to the 1,754 MW to match the Final EIS Base Case, Blend Scenario. Onshore wind capacity was added to each zone in direct proportion to the zonal distribution of wind resources in the NYISO Interconnection Queue as of November 2016. The Interconnection Queue is a list of projects with plans to become part of the wholesale grid. While not every project in the queue is built, it provides an indication of where new generation is likely to be sited. For the RTM Market Study cases, wind profiles were developed using the actual wind outputs from the 2016 production days as a baseline. These were extracted from NYISO's database and scaled for each zone using the Interconnection Queue zonal multiplier.

For the DAM Market Study cases, the same Interconnection Queue ratio was used to scale up the actual hourly wind forecasts from the 2016 Production Baseline days. The new hourly wind profiles were then multiplied by an average factor of 1.5. This was done to approximate the capacity factor assumed in the Final EIS Base Case, Blend Scenario, which is roughly 50% higher than the wind capacity factor reflected in historical NYISO forecasts.

Off-shore Wind Resource Profiles

The Final EIS Base Case, Blend Scenario assumes that ~1,000 MW of offshore wind capacity will interconnect to New York City and Long Island by 2030. The NYISO distributed 408 MW of this capacity to Zone K and 591 MW to Zone K[38] for the Market Study.

No actual or forecast offshore wind output data exists in the NYISO's historical data. Data from NREL's Wind Prospector tool was used to estimate forecasts and offshore wind generation output for the Market Study days.[39] NREL's modeled data was produced using 2012 weather measurements and is not correlated with the wind data from on-shore resources utilized in this study. The Final EIS assumes a higher capacity factor than is implied in the NREL data for offshore wind resources, as reflected in higher GWh output per MW-installed. To reflect the higher capacity factors assumed in the Final EIS, the NREL wind shapes were scaled up by an average factor of 1.5, using the same non-linear scaling function used for on-shore wind resources. The scaled NREL wind shapes were used for the day-ahead and real-time offshore wind profiles.

To create Day-Ahead profiles for offshore wind, the NYISO replicated Day-Ahead forecast errors by using zonal average onshore wind forecast errors from the 2016 Production Baseline days. The NREL profiles were then modified using this random forecast error.

Utility-Scale Solar Resource Profiles

Utility-scale solar was added to the Market Study based on the zonal quantities of capacity in the Final EIS, Exhibit 5-8. A per-MW profile was developed and applied to the assumed capacity per zone.

Until November 2017, the NYISO did not have a solar forecasting tool, so historical forecasts could not be used to develop Day-Ahead hourly solar profiles. For the January, March, and November Day-Ahead cases, an hourly output profile was created using actual zonal metered averages provided by a NYISO vendor. For the July case, a "clear sky" profile was used to calculate the irradiance that would result if every solar panel were oriented towards the south and angled at a 27% incline on a sunny day. Forecast irradiance was then scaled down to reflect a 13.5% capacity factor; the average statewide solar capacity factor reported by NYSERDA[40] . A Day-Ahead forecast error for the July day would have been likely because

38 Final Supplemental Environmental Impact Statement, May 19, 2016, Exhibit 5-20

39 Source: www.nrel.gov/grid/wind-toolkit.html Zone J: SiteID 76232; Zone K: SiteID 90992

40 https://www.nyserda.ny.gov/All-Programs/Programs/NY-Sun/Solar-Data

the timing of the weather front predicted for that day was uncertain.

For the RTM Market Study, vendor-provided solar profiles of measured output from rooftop solar inverters were used to create a front of the meter solar forecast for each day. Actual A/C solar output per interval per zone was scaled up proportionally using the NYISO's load forecaster.

Behind-the-Meter Solar Resource Profiles

The Final EIS presumes that behind the meter solar production will grow to 5,000 GWh/year by 2030[41] but does not specify where it will be located. NYSERDA reported 2016 behind the meter solar capacity[42] to be 712 MW, with an average capacity factor of 13.5% (AC output). The zonal distribution of 2016 behind the meter solar capacity is tabulated in Figure 24. The NYISO used a "clear sky" profile for each zone and a 13.5% capacity factor to forecast the total energy output by behind the meter solar in 2016. This value was scaled to the 5,000 GWh target established by the Final EIS Blend Scenario to determine that 4,200 additional MW of nameplate behind the meter solar capacity should be added for the Market Study.

Expected new behind the meter solar capacity was distributed zonally in proportion to where existing behind the meter solar is located. The percentage of the total installed behind the meter solar capacity was calculated for each zone. For example, Zone A had 38 MW of behind the meter solar capacity in 2016, or 5% of the State's total. Therefore, 5% of the behind the meter solar added for the Market Study was simulated in Zone A. To avoid double counting behind the meter solar that had already been installed in 2016, the equivalent of 500 MW nameplate solar capacity was subtracted from each day's profile.

Figure 31: Zonal Capacity of Behind the Meter Solar, 2016 Production Baseline and Market Study

Nameplate Behind the Meter Solar Capacity [MW]	Load Zone											Total
	A	B	C	D	E	F	G	H	I	J	K	
Production Baseline	38	23	56	2	34	113	114	18	23	82	209	712
Market Study	223	136	331	12	201	667	675	105	136	484	1236	4206
Scaling Percentage	5%	3%	8%	0%	5%	16%	16%	2%	3%	12%	29%	100%

[41] Final EIS, page 4-2

[42] PSC Case 15-E-0302, *Proceeding on Motion of the Commission to Implement a Large-Scale Renewable Program and a Clean Energy Standard*, Clean Energy Standard White Paper – Cost Study, New York State Department of Public Service, Table A.23 (April 8, 2016).

Small Hydroelectric Resources

The CES Order permits small hydroelectric resources to count towards the "50-by-30" goal when they up-rate or re-power existing dams. Some dams schedule flows based on recreational demands during the early summer months, but many of New York's existing run-of-river hydroelectric stations have limited ponding capabilities, making it difficult for them to maximize their output during peak load hours. Hydroelectric output is also affected by seasonal rainfall and snow melt patterns, with the lowest aggregate output occurring during the months of August and September. To create output profiles for the Market Study, actual output from the 2016 Production Baseline days was proportionally increased to match the zonal capacity of small hydroelectric projected in Final EIS exhibit 5-24, Base Case, Blend Scenario. The same profiles were used for both the Day-Ahead and real-time simulations.

Biomass and Anaerobic Digester Resources

The CES Order also includes biomass facilities (*e.g.*, wood burners) and Anaerobic Digesters, mostly Land Fill Gas (LFG) facilities, as qualified renewable resources. The Final EIS Base Case, Blend scenario includes an incremental 175 MW of these resources. These types of resources generally have operating restrictions that limit their flexibility. To simplify the modeling, a single production profile was selected for biomass resources based on a historical average, and a flat profile (70% of nameplate) was used for LFG generators. The 70% capacity factor for these resources is consistent with the capacity factors assumed in the New York DPS CES Cost Study.[43] The incremental additional MWs in each zone were based on Final EIS Exhibit 5-27 for LFG generators, and Exhibit 4-1 for biomass. The same, scaled profiles were used for both the Day-Ahead and the Real-Time Market Study cases.

Sum of Incremental Resources

Figure 32, Figure 33, Figure 34, and Figure 35 display the generation output profiles of all Incremental Renewable resource types (utility scale plus behind the meter solar) that were added to the Day-Ahead Market for the Market Study. Real-Time Market Study resource profiles are not presented here because they are either identical or significantly similar to those used for the Day-Ahead Market Study.

[43] Clean Energy Standard White Paper – Cost Study, New York State Department of Public Service, April 8, 2016, Table A.23. PSC Case 15-E-0302, Proceeding on Motion of the Commission to Implement a Large-Scale Renewable Program and a Clean Energy Standard, Staff White Paper on Clean Energy Standard (January 25, 2016).

Figure 32. Incremental Renewable Profiles in the DAM Market Study, January Day

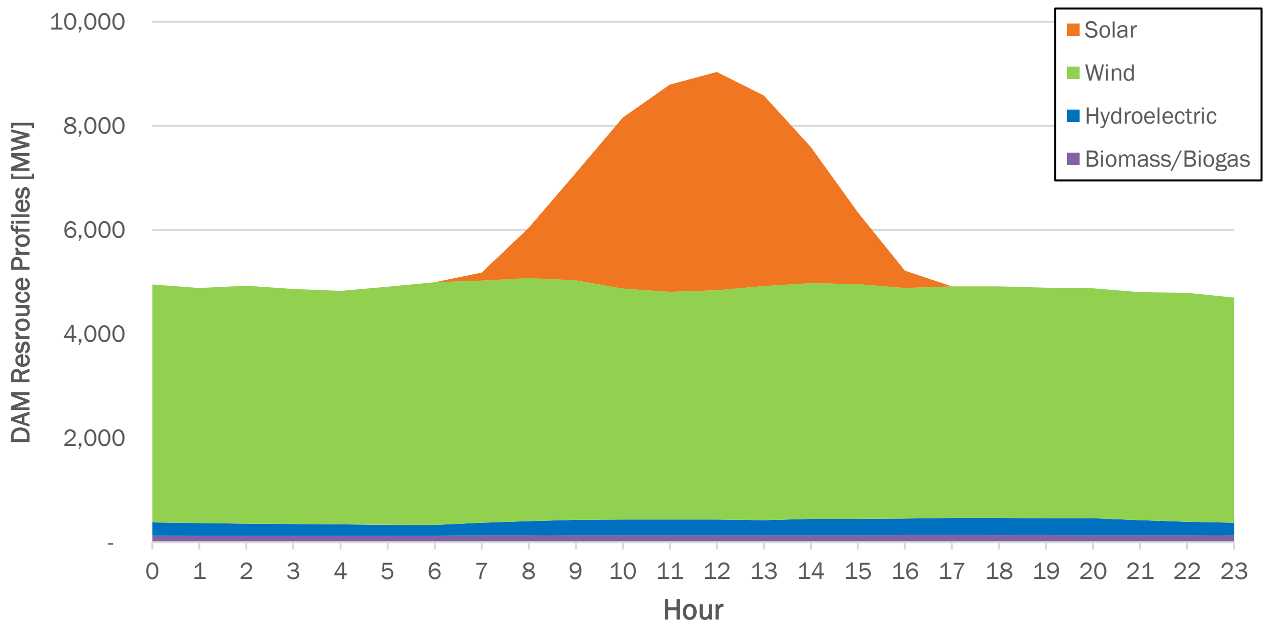


Figure 33. Incremental Renewable Profiles in the DAM Market Study, March Day

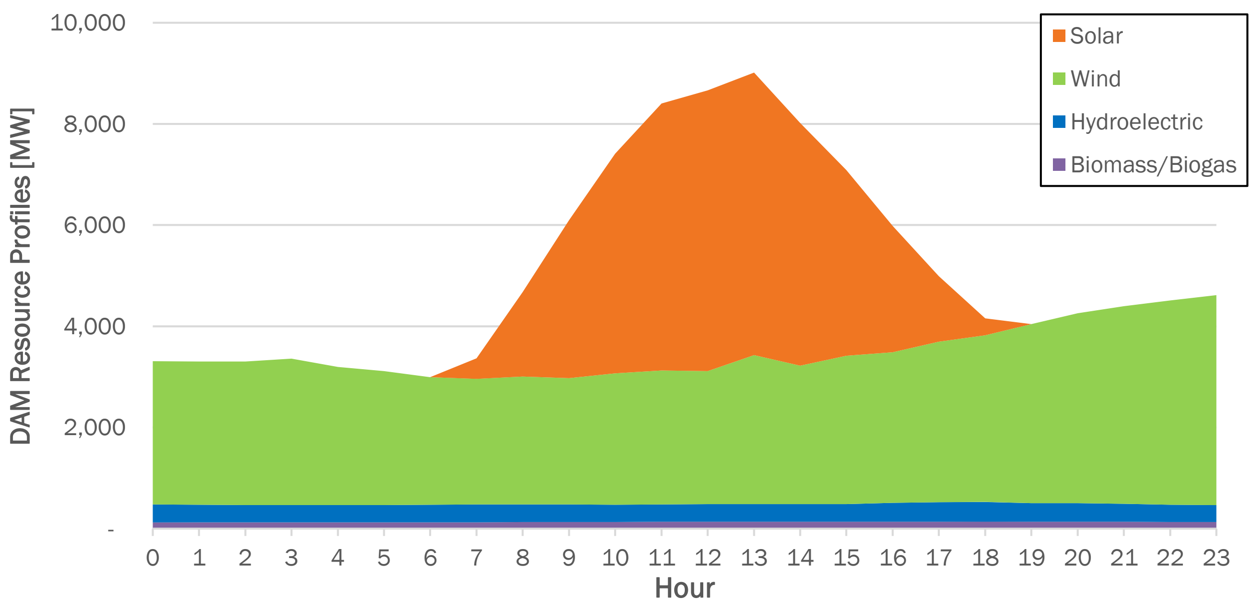


Figure 34. Incremental Renewable Profiles in the DAM Market Study, July Day

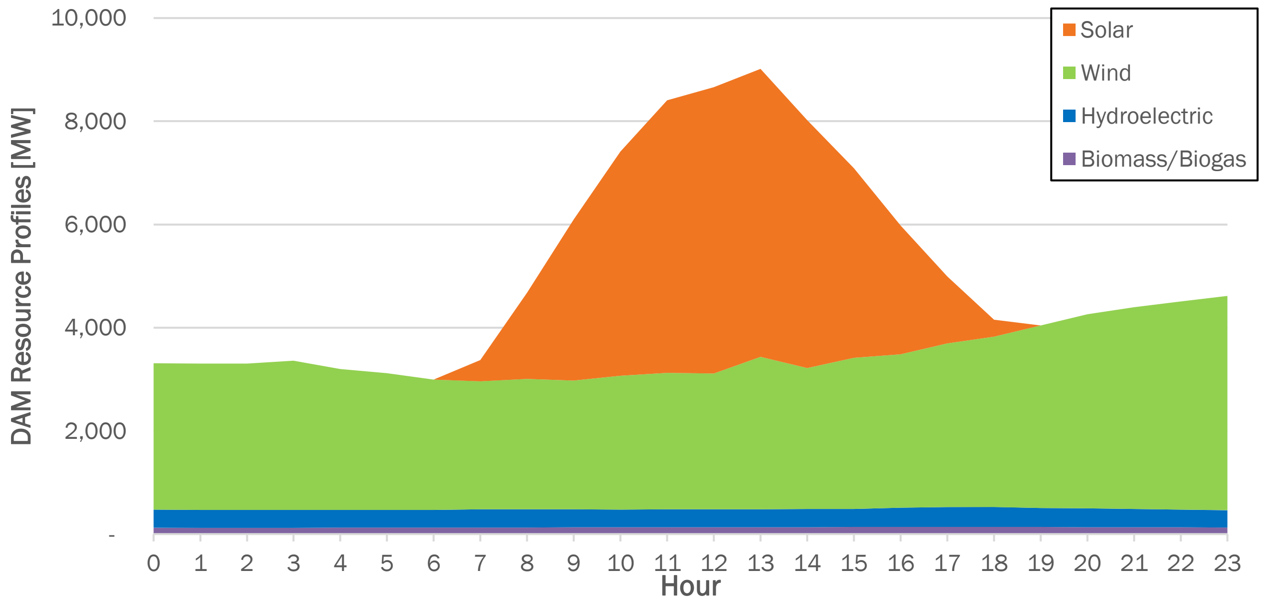
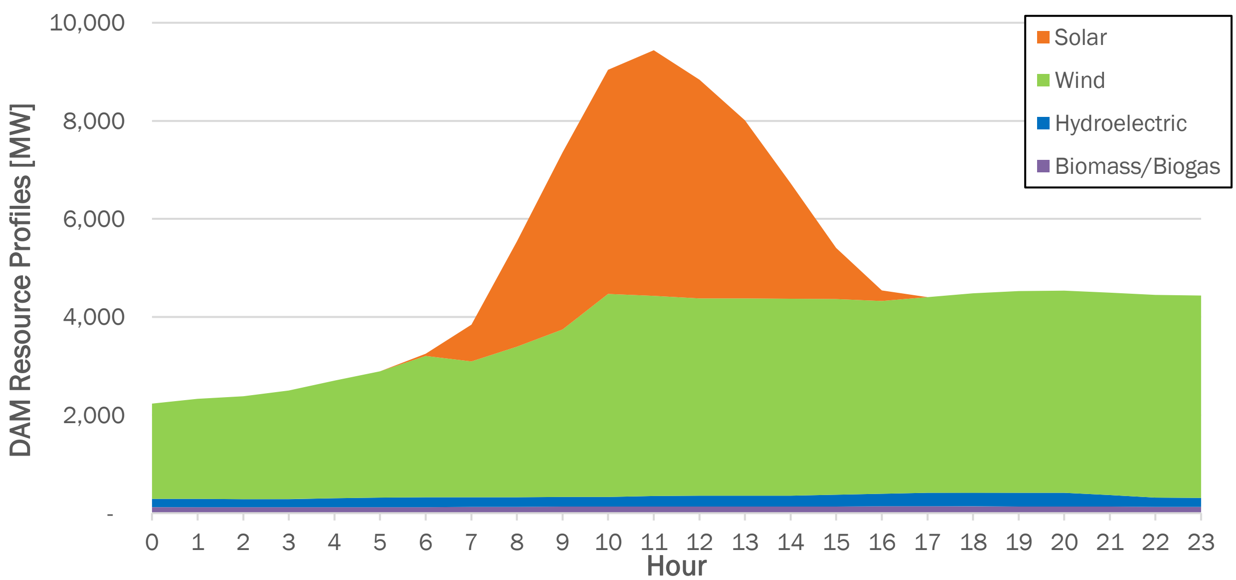


Figure 35. Incremental Renewable Profiles in the DAM Market Study, November Day



Offer Parameters of Incremental Renewables in Energy Market Study

Incremental renewables in the Market Study were modeled as Virtual Supply. The resources were assumed to offer at negative $47/MWh and to be price sensitive in both cases. Because Virtual Supply offers do not factor in physical constraints like ramp rates, this approach significantly simplified the operating characteristics that might be expected from actual renewable generators.

$47/MWh is the sum of the Federal Production Baseline Tax Credit (PTC) available to qualifying renewable resources and the average value of RECs awarded by New York State in 2016. When LBMPs are greater than negative $47/MWh, qualifying renewables profit from offering energy into the wholesale market. When LBMPs drop below negative $47/MWh, the resources are unlikely to offer energy because operation will cause them to lose money. The point of indifference for these resources is likely to change between now and 2030 because it is tied to the values of State and federal subsidies. Negative $47/MWh was used as a proxy to understand the effect that more subsidized renewables could have on market outcomes.

Virtual Supply and Demand Bids in the Day-Ahead Market Study

Predicting how the virtual traders might change their offers under the hypothetical market conditions explored was beyond the scope of this study. The Day-Ahead Market Study simulations used the same virtual bids that were in place for the corresponding Production Baseline Days. Day-Ahead Market Study outcomes should not be viewed as predictive of future virtual trading behavior. The outcomes are better used as indicators for how the commitment of existing resources might change if a large amount of renewable resources are added to the NYCA.

External Transactions

Electric energy is both imported into and exported out of New York. Exchanges with neighboring control areas are termed "transactions." Transaction flows are both long-term bilateral arrangements and short-term opportunities driven by Day-Ahead or real-time cost differentials.

The CES Order permits certain imports to contribute energy toward the "50-by-30" target but does not specify where they must come from. Forecasts of the future fuel supply mixes of neighboring control areas would have been necessary to model renewable imports flexibly. Because the projection of developments outside the NYCA was beyond the scope of this study, the study assumes that transactions were held to production baseline levels, except for transactions flowing from Hydro-Quebec (HQ) into New York, for all Market Study days. Transactions between the HQ control area and the NYCA were economically evaluated in each Market Study day.

The HQ control area is dominated by large ponding hydroelectric supply. Ponding hydro is expected to avoid selling at negative prices, because it is economically favorable to save energy until higher price intervals occur. Wheel-through transactions from HQ to neighboring control areas were held to production baseline values, like all other transactions with neighboring control areas.

The differences between the Production Baseline flows and the Market Study flows for HQ to NYISO transactions are presented in Supplemental Appendix 6: Hydro-Quebec Transactions. The transaction flows between other control areas were unchanged from the 2016 actual values and can be found on the

NYISO's OASIS site. They may be calculated by subtracting Interface Limits and Flows from Power Grid Data. It should be noted that the production schedules in Supplemental Appendix 6 do not perfectly match the data in OASIS. Some transactions scheduled by the NYISO market solver do not clear the subsequent checkout process that must occur between the importing and exporting control areas before a transaction may flow, and these values may be adjusted after the fact.

Retirements

Some existing units, primarily fossil-fuel generators with high marginal costs, are expected to retire by 2030 due to age, economics, and/or regulatory pressure. However, the Market Study assumed all generators existing on the Production Baseline days were available because the NYISO cannot predict which generators may retire[44]. Nuclear generation was included in the Market Study because the future of upstate nuclear facilities remains unclear.

Any resource that bid into the energy market during a Production Baseline day was also offered for commitment and dispatch in the corresponding Market Study day. Some high cost units that may retire before 2030 were less likely to be selected in the Market Study cases because they could not operate as economically as competing resources. The resulting market outcomes provide an indication of how the NY Power System might perform if these units retire.

Capacity Market Study Methodology

Similar to the Energy Market Study, the objective of the Installed Capacity (ICAP) Market Study was to understand the impact that Incremental Renewable capacity might have on ICAP market outcomes. A "Base Case" representative of 2016 market conditions was compared to a hypothetical "Market Study" scenario with renewable capacity equal to the quantity targeted in the CES Order. The same mix of Incremental Renewables used in the Energy Market Study was modeled. The Market Study incorporated direct effects such as changes in the average performance of capacity suppliers, but did not attempt to anticipate other market responses such as new or expanded transmission infrastructure, resource retirements, or changes in import and export patterns.

Capacity Market Base Case

The Capacity Market Base Case represents the ICAP market as it exists today. Current market values or averages of recent market values were used for parameters such as Demand Curves, capacity requirements, and capacity supplies. Conditions were primarily based on Capability Year 2017/2018

[44] No formal retirement notice for the Indian Point nuclear power plant had been received when the NYISO began this study.

capacity market supply and demand parameters.[45] The analysis used recent historic data when Capability Year 2017/18 data was unavailable. For example, the Winter 2017/18 Capability Period begins in November 2017, and capacity sales data did not exist at the time the Market Study was performed.

Figure 36 details ICAP market parameters used for the Base Case, including the Summer and Winter Capability Periods, respective capacity market parameters and NYISO ICAP Spot Market Auction results from April 2017 (2016/17 Winter Capability Period) and May 2017 (2017/18 Summer Capability Period). The April 2017 auction was part of Capability Year 2016/17 with the attendant load forecast, Installed Reserve Margin (IRM), Locational Minimum Installed Capacity Requirements (LCRs), and translation factor data.

Base Case parameters were developed using current capacity market supply and demand data. For convenience, inputs are presented in a similar format to the Monthly Unforced Capacity (UCAP) Report that is published on the NYISO's website.[46] Other publically available assumptions included current reference prices, the 2017 Load Forecast, locational de-rating factors, and NYCA minimum and LCR percentages. The Base Case and Market Study Case did not include an assumption or forecast of generator retirements or facility upgrades. The majority of the available supply parameters used an average over full historic capability periods.[47] Averaging capacity parameters (*e.g.*, imports) over full capability periods smoothed out month-to-month volatility in those parameters. As with the capacity sales data, complete data for the current Capability Year were not available due to the timing of the IPP Market Study because it was conducted in the middle of the Summer Capability Period. Recent historic data from prior Capability Periods were used, as necessary.

All megawatt values other than the load forecast values are presented in UCAP MW. Capacity sales based by Unforced Capacity Deliverability Rights (UDRs; i.e., capacity associated with certain controllable transmission) are counted among the "Generation/SCR UCAP Available**" UCAP data and not among the "Imports" UCAP data.

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[45] The Study Case builds on the Base Case and therefore relies on many of the same inputs and assumptions.

[46] These monthly reports are available at: <http://www.nyiso.com/public/markets_operations/market_data/icap/index.jsp>. Path to individual reports: Monthly Reports > Monthly UCAP Reports > [YEAR] > [SELECT REPORT]

[47] A single Capability Year contains months from two calendar years. The Capability Year begins with the Summer Capability Period. The Summer Capability Period includes the capacity delivery months of May through October. The Winter Capability Period includes the capacity delivery months of November through the following April.

Figure 36: ICAP Market Parameters for Base Case

UCAP SALES	NEW YORK CONTROL AREA							
			G-J Locality					
					New York City		Long Island	
[UCAP MW]	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
Spot Auction Price ($/kW-Month)	$4.24	$0.00	$10.33	$2.65	$11.64	$2.65	$4.24	$0.54
Load Forecast 2017	33,177.8	33,177.8	16,061.3	16,061.3	11,670.0	11,670.0	5,427.1	5,427.1
LCR/IRM Percentage	118.00%	118.00%	90.50%	90.50%	81.50%	81.50%	103.50%	103.50%
Demand Curve ICAP Ref Point	$ 9.08	$ 9.08	$ 14.84	$ 14.84	$ 18.61	$ 18.61	$ 12.72	$ 12.72
ICAP/UCAP derating factor	9.68%	7.90%	7.34%	5.69%	4.36%	5.29%	6.90%	6.91%
UCAP Ref Point	$ 10.05	$ 9.86	$ 16.02	$ 15.74	$ 19.46	$ 19.65	$ 13.66	$ 13.66
UCAP Requirement	35,361.4	36,058.8	13,468.1	13,708.2	9,096.0	9,008.4	5,229.6	5,228.7
Demand Curve Zero Crossing	112.00%	112.00%	115.00%	115.00%	118.00%	118.00%	118.00%	118.00%
UCAP at $0	39,604.8	40,385.9	15,488.3	15,764.4	10,733.3	10,629.9	6,170.9	6,169.9
Demand Curve Slope	(0.0024)	(0.0023)	(0.0079)	(0.0077)	(0.0119)	(0.0121)	(0.0145)	(0.0145)
Generation/SCR UCAP Available**	36,647.7	39,805.0	14,206.0	15,445.4	9,767.4	10,543.3	5,903.7	6,155.9
Imports	1,413.7	1,172.9	0.0	0.0	0.0	0.0	0.0	0.0
Exports	138.3	146.1	0.0	0.0	0.0	0.0	0.0	0.0
Unoffered MW	101.7	177.5	16.8	13.1	9.1	8.9	6.7	21.4
Unsold MW	4.6	164.1	4.0	14.3	4.0	18.4	0.6	1.8
Total MW Cleared***	37,816.8	40,490.2	14,185.2	15,418.0	9,754.3	10,516.0	5,896.4	6,132.7
MW Cleared Above Requirements	2,455.4	4,431.4	717.1	1,709.8	658.3	1,507.6	666.8	904.0
% Cleared Above Requirements	6.94%	12.29%	5.32%	12.47%	7.24%	16.74%	12.75%	17.29%

*Capacity supply and demand values per the assumptions outlined in the Integrating Public Policy - ICAP project

**Includes UDRs

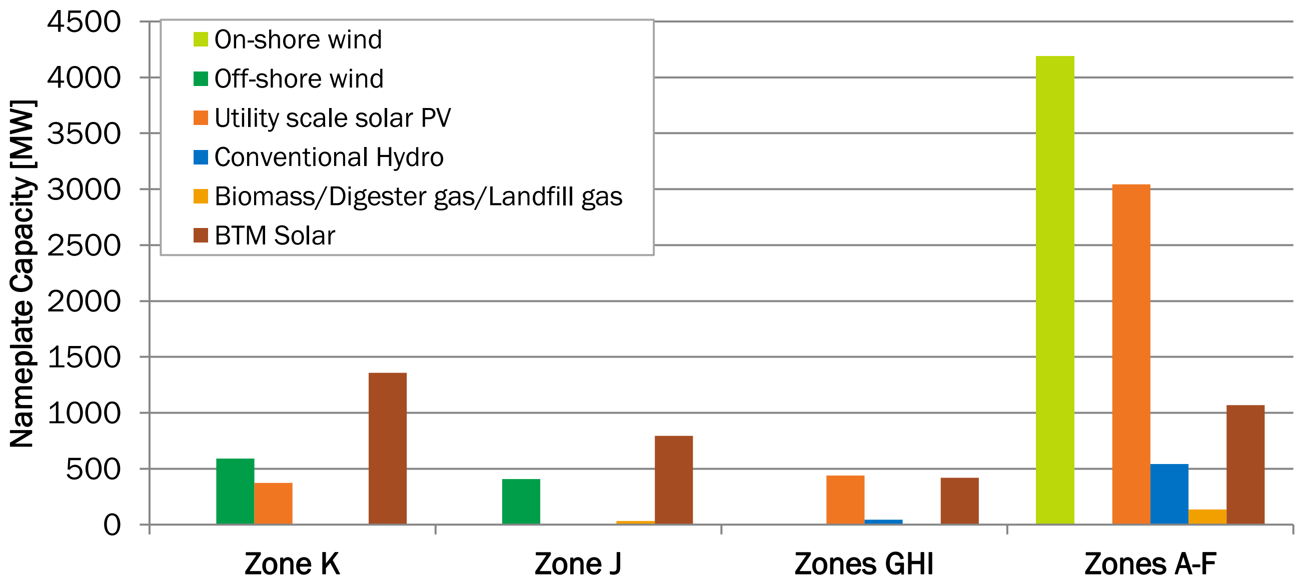
***Total MW Cleared = Generation/SCR UCAP Available + Imports - Exports - Unoffered MW - Unsold MW

Capacity Market Study Case

The Market Study Case was defined as the Base Case plus the incremental renewable capacity anticipated in the CES Final Supplemental Environmental Impact Statement.[48] The Market Study Case used the same market rules and design elements as the Base Case. The resources added are identical to those added for the Energy Market Study.

Onshore wind and a combination of utility-scale and behind the meter solar accounted for the majority of resource additions in NYISO load zones A through I. Utility scale and behind the meter solar and off-shore wind accounted for the majority of resource additions in NYISO Load Zones J and K (New York City and Long Island, respectively). Figure 37 details the nameplate capacity of the additional resources based on Localities. In total, 13,444 megawatts of nameplate capacity were added to the ICAP market.[49] Additional renewable resource type, quantity, and location were taken directly from the CES Final Supplemental Environmental Impact Statement "Blend Base Case".[50]

Figure 37: Renewable Resources Added for Capacity Market Study



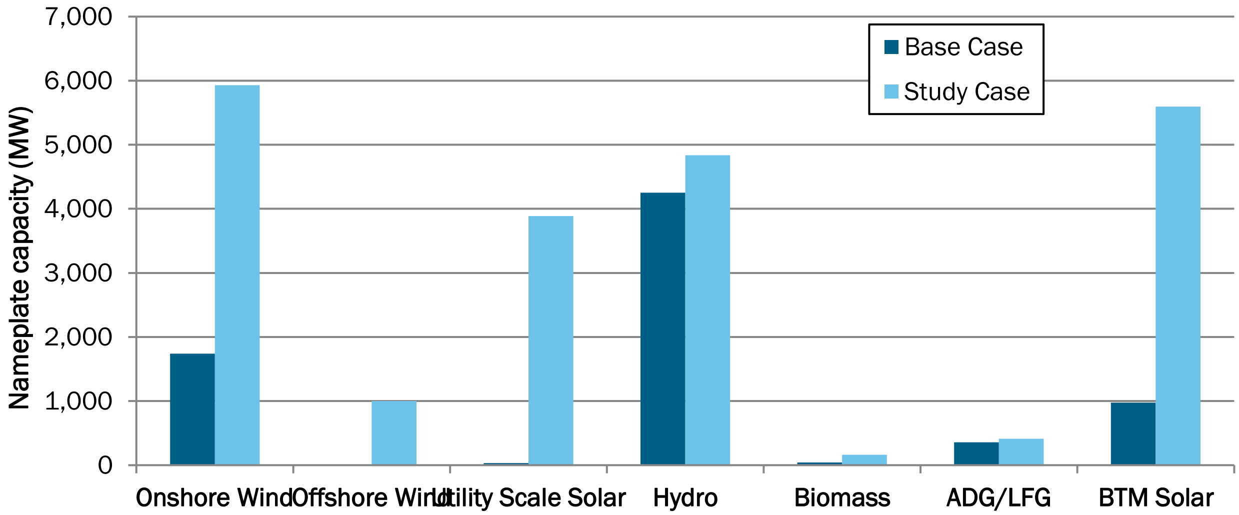
As a result of adding this capacity, total available capacity in each capacity location increased. Figure 38 shows available ICAP in the Base Case and Market Study Case.

48 This document is available at: <http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={424F3723-155F-4A75-BF3E-E575E6B0AFDC}>.

49 By location that is: 8,978 megawatts of nameplate capacity in Load Zones A-F, 905 megawatts in Load Zones G, H, and I, 1,235 megawatts in Load Zone J, and 2,326 megawatts in Load Zone K.

50 (http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={424F3723-155F-4A75-BF3E-E575E6B0AFDC})

Figure 38. Nameplate Capacity of Renewable Resources in the Base Case and the Market Study Case



The Installed Capacity (ICAP) quantity of the Incremental Renewables was converted into the UCAP quantity of the Incremental Renewables. UCAP is the product transacted in the NYISO ICAP market and thus determines capacity revenues for suppliers and capacity costs for loads. The ICAP quantity of resources that are modeled as modifying load (*i.e.*, behind the meter solar) were also converted to a UCAP quantity based on their availability during peak periods. The UCAP of the behind the meter solar resources was then deducted from the peak load forecast. This produced a 'net' peak load value which represents the initial peak load forecast less the output produced by these resources during the peak period.

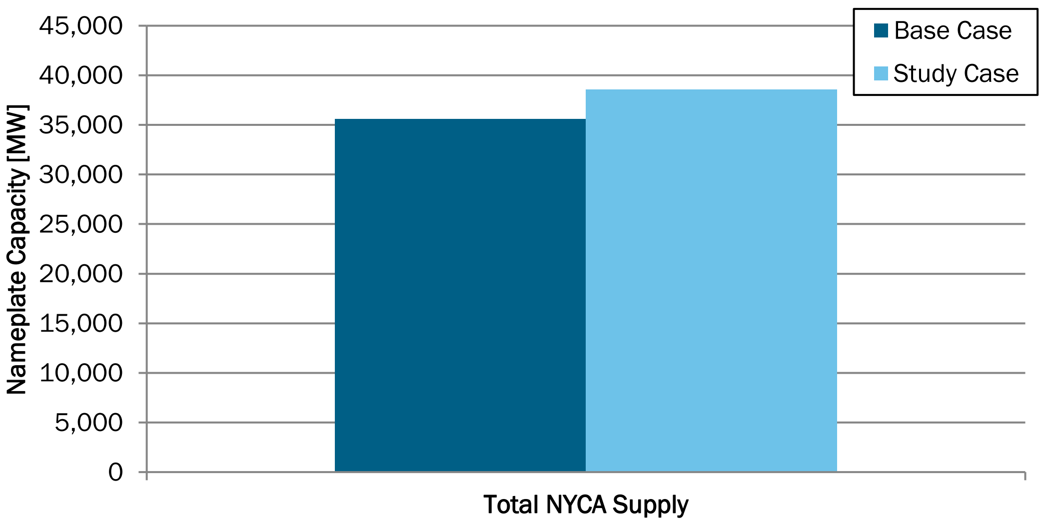
The NYISO ICAP Manual specifies a "de-rating factor" used to convert ICAP to UCAP for certain types of renewable resources that do not have historical performance data. Figure 39 provides the de-rating factors used to convert the ICAP values of Incremental Renewables to UCAP. Statewide average de-rating factors were used for resources that do not have published de-rating factors in the ICAP Manual.

Figure 39. De-rating Factors Used to Convert Additional Renewable Resource ICAP to UCAP

Resource Type	Summer De-rating Factor	Winter De-rating Factor	Source
On-shore wind	0.90	0.70	ICAP Manual, pg. 4-23
Off-shore wind	0.62	0.62	ICAP Manual, pg. 4-23
Solar (utility-scale and behind the meter)	0.54	0.98	ICAP Manual, pg. 4-25
Run-of-River Hydroelectric	0.50	0.40	Approximate NYCA average
Biomass/Landfill Gas	0.40	0.40	Approximate NYCA average

Figure 40 shows the resulting available ICAP in both the base case and the Market Study. Unforced Installed Capacity (UCAP) Available – Total NYCA Generation Supply can be easily identified as increasing for the Market Study Case versus the current Base Case Supply stack.

Figure 40: Unforced Installed Capacity Available



NYISO Staff analyzed how Incremental Renewables in the Market Study might affect the following four ICAP market parameters.

New York's Installed Capacity Requirements

The NYISO defines the amount of capacity necessary to ensure resource adequacy ("requirement setting process") as one loss-of-load event in ten years. To determine it, a Monte Carlo analysis is performed to compare the upcoming Capability Year's load with available resources. For example, higher net load yields a higher capacity requirement. Also, a set of well-performing resources that are always available when called upon would lead to a lower capacity requirement than a set of poorly-performing resources that are often out-of-service (or otherwise not producing energy) when called upon.

Many of the additional renewable resources that the CES Final Supplemental Environmental Impact Statement assumes will enter the market are intermittent renewables. Historically, intermittent renewables in New York have not performed as reliably during peak load periods as traditional fossil fuel resources. Because they are likely to have lower availability during peak load periods, intermittent renewables would likely force New York's overall installed capacity requirement to increase. A model illustrating this result was included by the NYISO in its comments filed in the PSC's CES proceeding.[51] This

[51] PSC Case No. 15-E-0302, *Supplemental Comments of the New York Indep. Sys. Operator, Inc.*, July 8, 2016: available at: h<ttp://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={039DE249-C6D9-4A80-8183-349261546F1B}>.

model estimates that there is a one-for-one relationship between intermittent renewable capacity that is not expected to be available during peak, and capacity that needs to be maintained to ensure resource adequacy. In other words, intermittent renewable capacity that is unavailable during peak periods requires some form of firm backup. In the Capacity Market Study, changes in the installed capacity requirement due to the Incremental Renewables were estimated using that assumption.

Locational Minimum Installed Capacity Requirements ("LCRs")

The NYISO's comments in the PSC CES proceeding were limited to how intermittent renewables could affect the statewide IRM.   Intermittent renewables throughout the State could also have an effect on the LCRs, which set the requirements for each Locality.[52] Accordingly, this IPP Market Study used the same model as the PSC CES to estimate changes in LCRs.

The Effects of Behind the Meter Solar on Wholesale Peak Load and Capacity Requirements.

The CES assumes that approximately 3,640 MW of behind the meter solar will contribute to meeting the "50-by-30" goal. Additional behind the meter resources will affect the wholesale markets by reducing both net peak load and peak load forecasts. This in turn will affect capacity requirements. For the Capacity Market Study, the NYISO assumed that each one (1) MW of behind the meter solar would decrease summer peak load by 0.46 MW. The same on-peak availability factor was also assigned to those new wholesale solar resources that would be eligible to sell 46% of their ICAP as UCAP in the NYISO ICAP market.[53]

Although the performance of behind the meter solar could also increase load forecast uncertainty, the Capacity Market Study did not account for potential changes in load variability.

ICAP Demand Curve Reference Point

Parameters that influence the ICAP Demand Curve reference point include the ratio of available ICAP between the Winter Capability Period and the Summer Capability Period (Winter-to-Summer Ratio, or "WSR" [54]); and the assumed net Energy and Ancillary Services revenues of the peaking plant utilized in order to established the respective Demand Curve parameters. Differences in available capacity between the Summer and Winter Capability Periods contribute to differences in capacity prices between these periods. The Winter-to-Summer ratio is used to account for those price differences and adjust each Demand Curve's reference point to ensure that the respective Demand Curve peaking plant is revenue

[52] A Locality is a single LBMP Load Zone or set of adjacent LBMP Load Zones within which a minimum level of Installed Capacity must be maintained. Presently in the NYCA the Localities are Load Zone J, Load Zone K and the G-J Locality.

[53] This study assumed that the all of the MW of Incremental Renewables would obtain CRIS.

adequate on an annual basis. The 2017-18 Capability Year WSR values for the NYISO ICAP Market[55] were used for the Base Case.

For the Market Study Case, WSR's were re-calculated after adding the Incremental Renewables. The Incremental Renewables had identical winter and summer ICAP values, which reduced their WSRs. Figure 41 lists the WSRs used for both the Base Case and Market Study Case.

Figure 41: Winter to Summer Ratio

Winter to Summer Ratios	Base Case	Market Study
NYCA	1.037	1.030
G-J	1.054	1.050
NYC	1.077	1.074
LI	1.075	1.065

The net Energy and Ancillary Services revenues of the respective Demand Curve peaking unit affect the amount of revenue that the unit must recover in the ICAP market. The net revenue values used to determine the 2017/18 ICAP reference point[56] were applied for the Base Case. For the Market Study, it was conservatively assumed that the net Energy and Ancillary Services revenues of the peaking plant would be zero (0$/kW-y), as a result of the high penetration of price-taking energy resources (i.e., resources that offer at $0.00) and low day-ahead LBMPs observed in the Energy Market Study. This assumption produced a higher capacity price estimate than other net revenue value assumptions would have.

Sensitivity Analyses

A series of sensitivity analyses were developed to explore the uncertainty surrounding four parameters used in the Market Study Case.

1. **De-rating factors assigned to on-shore wind, offshore wind, and solar.**

   The de-rating factors assigned to capacity resources affect both the shape of the capacity

[55] The Winter-to-Summer values for the 2017-18 Capability Year are available at: <http://www.nyiso.com/public/webdocs/markets_operations/market_data/icap/Reference_Documents/2017-2021_Demand_Curve_Reset/Final%20WSR%20for%20CY%202017-2018.xls>.

56 Net energy and ancillary service revenues used to determine 2017 Capability Year ICAP Demand Curve Reference Points

NYCA: $35.70/kW-y

G-J LOCALITY: $40.39/kW-y

NYC: $55.26/kW-y

LONG ISLAND:$104.20/kW-y

http://www.nyiso.com/public/markets_operations/documents/tariffviewer/index.jsp MST Section 5.14.1.2.2.3

Demand Curves and the supply of UCAP available in the market. It is important to understand how the market could respond to variations in both current and future estimates of de-rating factors for intermittent renewables. For example, a more efficient wind turbine with a higher capacity factor may require a different de-rating factor from those published today.

2. **Effects of the additional renewable resources on the Installed Reserve Margin and the Locational Minimum Installed Capacity Requirements.**

   Studies like the annual IRM report[57] published by the New York State Reliability Council have shown broadly that changes in resource performance affect the values of both the IRM and LCRs, but causality is not yet well understood. In order to understand the effects of IRM and LCR uncertainty on capacity market outcomes, they were parameterized, and Market Study results were re-calculated.

3. **Net Revenue of Demand Curve Hypothetical Proxy Unit**

   To provide stakeholders the opportunity to form their own central price estimates, the net revenue of the demand curve peaking unit was parameterized and market outcomes were re-calculated.

4. **The quantity of capacity that would need to remain present the market but not clear in any auction or be in a certified Bilateral Transaction to return prices to Base Case levels**

   This sensitivity identified the quantity of capacity that would need to exist in the market (*e.g.*, for the purposes of setting capacity requirements) but not clear in any auction or as a bilateral ('uncleared UCAP') in order for capacity prices to return to Base Case levels. Uncleared capacity could occur for various reasons, like increased export transactions, reduced import transactions, and internal capacity suppliers offering capacity at a price above the market clearing price. This Market Study was not designed to forecast or otherwise estimate future market outcomes. Without providing such a forecast, this sensitivity case helps understand the additional surplus capacity provided by the Market Study Case resources.

57 The 2017-18 IRM report is available at: <http://nysrc.org/pdf/Reports/2017%20IRM%20Study%20Report%20Final%2012-2-16%20(002).pdf>.

Appendix B: Detailed Study Results & Discussion

Energy Market Study Results

This section explores the results of the Energy Market Study. Net load profiles, the prices of energy and ancillary services, unit dispatch and commitment, renewable curtailments, net load ramp, total generator ramp, and flexible generator ramp are discussed. Background information, key assumptions, and details about how the study was conducted may be found in Appendix A: Study Methodology. Source data may be found in the Supplemental Appendices, the contents of which are summarized in Appendix C: Description of Supplemental Appendices.

The existing transmission system limits the amount of energy that can flow across New York at any given time. A significant bottleneck, referred to as Central East, persistently forms around a group of transmission facilities. The Market Study reports average Locational Marginal Based Prices (LBMPs) for the load zones West and East of this constraint, where "West" refers to Load Zones A-E, and "East" refers to Load Zones F-K. The severity of congestion along Central East is evident in price separation between West and East.

Relative price differences and trends reported between West and East may be indicative of future NY Power System needs, but the Market Study clearing price values are not predictive of future clearing prices. For example, prices at or near negative $47/MWh appeared in intervals when modeled renewable resources were on the margin. Negative $47/MWh was chosen as the offer floor for Incremental Renewables because that is the point at which qualifying renewables are price sensitive today. How this value may change in the future is difficult to determine, but the conditions that arose in the Market Study are still relevant.

January Real Time Market Study Day

The NYISO is unable to provide solutions from the real-time January Market Study case because the offline market software could not converge on a reasonable solution for many 5-minute intervals. This was not because the problem was impossible to solve. Rather, the initial assumptions made by RTC did not enable acceptable solutions to develop. The RTC and RTD engines execute a limited number of solution passes in order to meet their posting deadlines every 15 and 5 minutes, respectively. In its first iteration, RTC creates an initial unit commitment schedule with the assumption that all units are available. In subsequent iterations, RTC works to reconcile that schedule with availability constraints. While simulating the January Market Study day, RTC repeatedly failed to resolve those constraints, producing illogical market outcomes.

It is unclear why the solution process for the real-time January case in particular proved problematic. Modeled renewables added complexity by expanding the pool of possible dispatch solutions, but these modeled renewables did not prevent the other Market Study cases from solving. Power flow on the January day was significantly constrained by outages of 345 and 230 kV transmission lines in the West, but solution failures persisted even when the case was re-run without those constraints. It was a high wind day, but the wind output was higher on the November day. Likewise, it was a high load day, but the load was higher on the July day. Ultimately, the NYISO was not able to attribute the solution failures to any specific variables.

The real-time January Market Study outcome suggests that under potential future conditions, energy market optimization algorithms may need to be improved to ensure that the NYISO can continue to post accurate commitment and dispatch instructions in real time. Current renewable generation penetration levels indicate that the NYISO does not expect to encounter optimization algorithm problems like this in the near future.

A similar problem was identified when virtual trading was first introduced to the DAM. New heuristics were introduced that enabled the DAM optimization to solve more efficiently. Similar changes could be explored as enhancements for the real-time solution engines. Because additional solution parameters could increase solve time, any changes will need to be carefully evaluated prior to implementation.

Shift in Real Time Generator Output

13,444 MW of additional renewable capacity was modeled for the Market Study. This equates to 35% of the total Installed Capacity of New York in 2016. Notably, the share of generation from renewable resources in the real-time Market Study was not equivalent to their share of the asset mix. Output from renewable resources only increased an average of 13% during the March, July, and November Market Study days compared to the Production Baseline days. Figure 42 and Figure 43 detail how the generation mix changed for each Market Study case compared to the Production Baseline cases.

Figure 42: Total Generation by Renewable Resources in Real Time [%]

Case	Production Baseline	Market Study
March	27%	41%
July	14%	27%
November	26%	37%

Figure 43. Share of Internal Generation by Resource Type in Real Time [%]

Resource Type	Production Baseline			Market Study		
	March	July	Nov.	March	July	Nov.
Combined Cycle	34%	34%	34%	21%	27%	22%
Peakers	2%	6%	1%	3%	5%	4%
Conventional Hydroelectric	23%	12%	20%	13%	7%	9%
Nuclear	30%	24%	35%	29%	24%	34%
Steam Turbine	8%	23%	3%	5%	17%	3%
Other Renewable	3%	2%	6%	28%	19%	28%

Renewable resources in the Market Study displaced generation that was provided by combined cycle, conventional hydroelectric and fossil-fuel burning steam turbine generators in 2016. In real time, the share of total internal generation from conventional hydroelectric resources decreased by 50% on average across the July, November and March Market Study days. The share produced by combined cycle units decreased 30%. In contrast, the share of total internal generation from non-hydroelectric renewables increased 21% on average across the three Market Study days.

Transmission constraints and differences in asset siting produced variations in the generation mix between East and West. Conventional hydroelectric units in the West were committed less frequently in the Market Study, absorbing the bulk of the output reduction for the area. Combined cycle units and steam turbines absorbed the majority of the output reduction in the East.

Figure 44: Variations in Output as a Share of Total Internal Generation [%]

Resource Type	Change in Market Study [%]					
	West			East		
	March	July	Nov.	March	July	Nov.
Combined Cycle	-5%	-10%	-7%	-32%	-11%	-29%
Conventional Hydroelectric	-25%	-17%	-24%	-1%	0%	0%
Steam Turbine	0%	-4%	0%	-7%	-11%	-3%
Other Renewable	39%	37%	36%	41%	26%	37%

Net Load Profiles

Net Load is the sum of virtual and physical load minus Virtual Supply. Net Load typically increases over the course of the day, cresting during the late afternoon and early evening hours before tapering off. Figure 45, Figure 46, Figure 47, and Figure 48 present the load profiles produced by the NYISO's Day-Ahead simulations. "Production Load" is the load for the baseline re-run of the Day-Ahead Market for the selected 2016 days. "Study Load" is the Production Load minus the forecast behind the meter solar generation for the Market Study day and was calculated on an hourly average basis. This approach is consistent with the current market treatment of behind the meter solar as a load modifier. “Study Net Load” was calculated as Study Load minus the hourly awards of Incremental Renewables modeled using Virtual Supply.

The increase in renewable generation in the Market Study changed the shapes of the Day-Ahead net load curves significantly. behind the meter solar caused the Market Study load to fall below the Production Baseline load during daylight hours, while utility-scale solar and other front of the meter renewable resources caused the total net load to fall below the Production Baseline load in all hours. This suggests that the “50-by-30” mandate could significantly alter the daily net load managed by the NYISO. It is important to note that the Market Study increased the amount of price sensitive load. When the wholesale energy price dropped below negative $47/MWh in the Market Study, Incremental Renewable resources curtailed output, increasing net load. The overall reduction in net load observed on Market Study days impacted clearing prices and the commitment and dispatch of existing resources.

Figure 45: Day-Ahead Net Load Profile, January Day

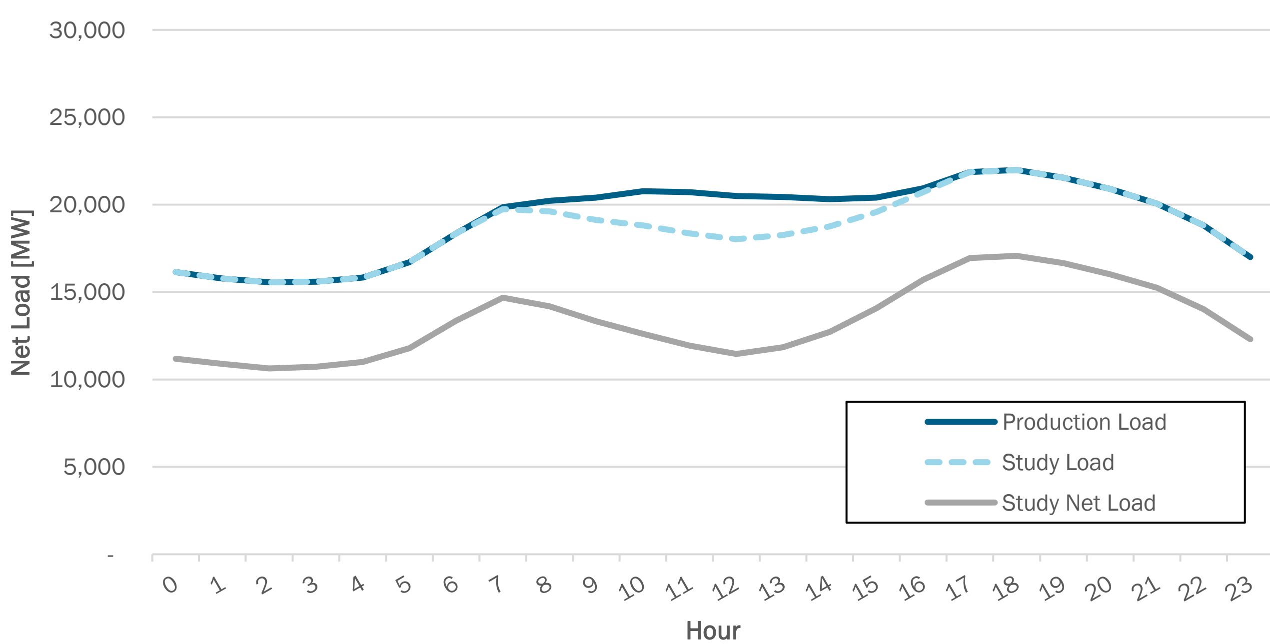


Figure 46. Day-Ahead Net Load Profile, March Day

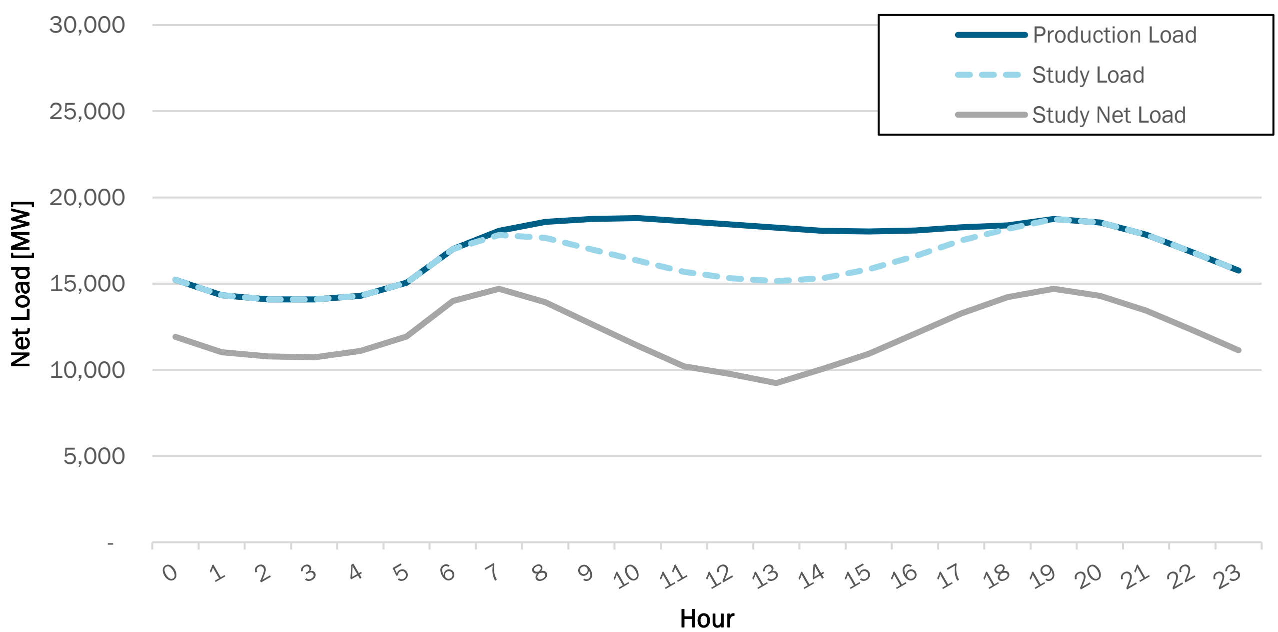


Figure 47: Day-Ahead Net Load Profile, July Day

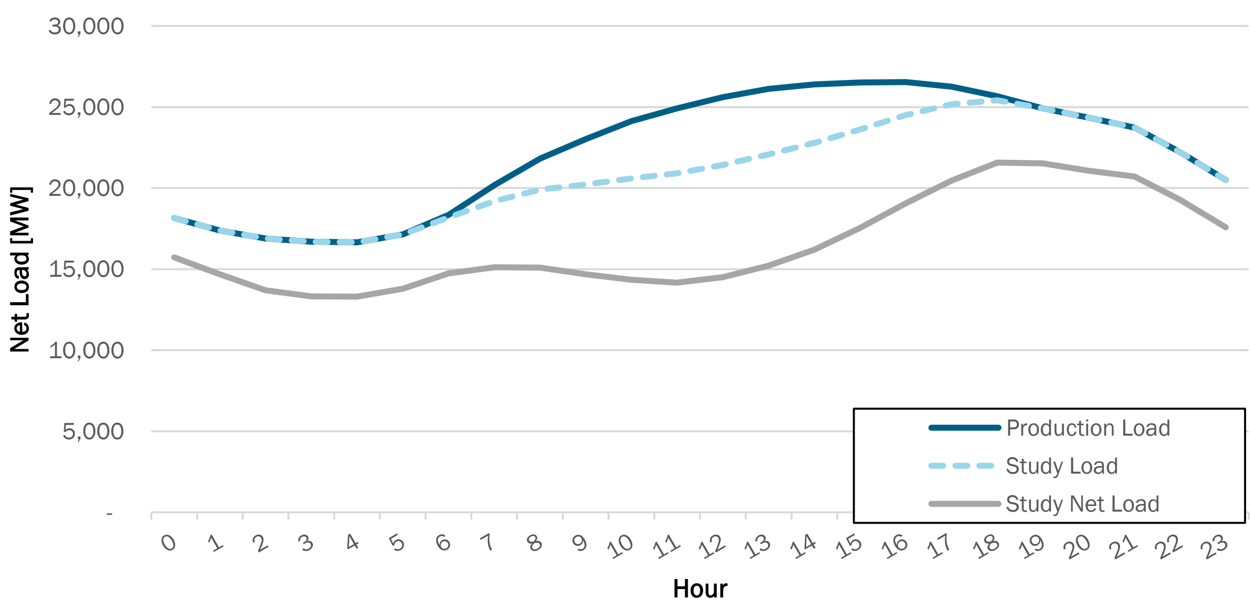
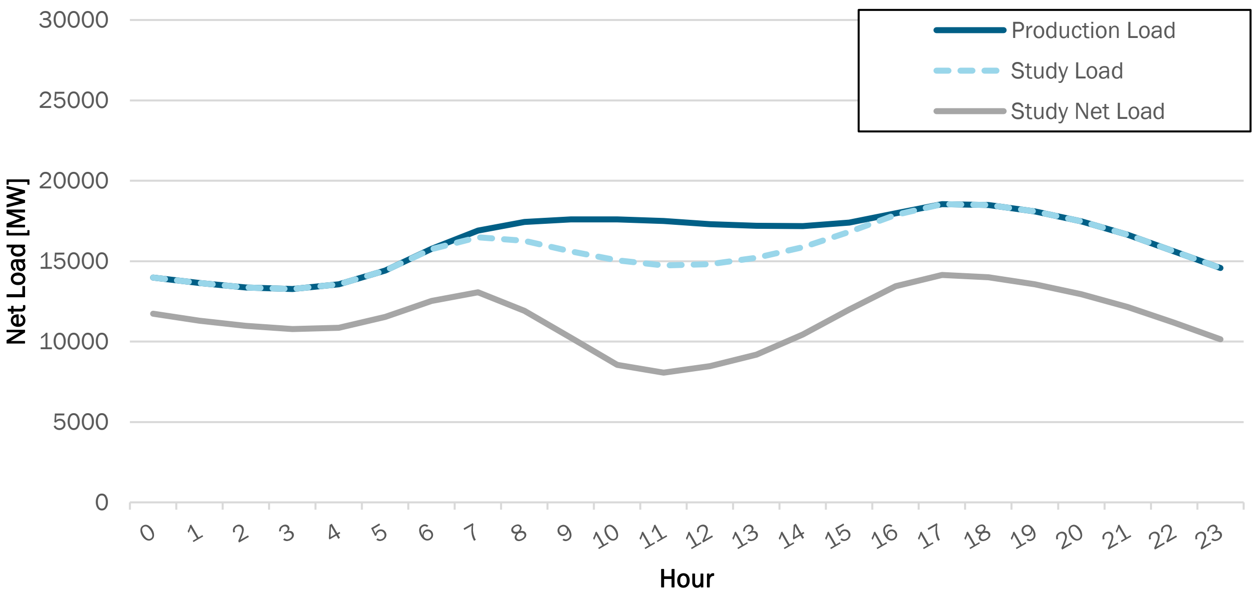


Figure 48: Day-Ahead Net Load Profile, November Day



Real-Time Net Load Forecast Uncertainty

Incremental Renewable resources in the Market Study drove greater uncertainty in the real-time optimization because the market software was unable to accurately predict their movements. This is evident in Figure 49, Figure 50, and Figure 51, which compare real-time Market Study net load ramp to Production Baseline net load ramp for each day. An indicator of supply and demand volatility, net load ramp is calculated as the difference in real-time load from one five-minute interval to the next. As wind and solar generators react to changing weather conditions, the load that must be served by the NY Power System also changes rapidly. The larger the step in net load ramp between intervals, the farther the NY Power System supply must move to catch up with real-time conditions.

Net load ramp is an important factor in commitment decisions made by RTC. For example, during an interval in which RTC perceives that net generation capacity is lower than what is required to meet the expected load over the next 30 minutes, it may instruct additional fast start units to come online. In subsequent intervals, if output from intermittent renewables increases significantly, RTC may de-commit the same resources because their output is no longer needed. The RTM software managed load uncertainty primarily by cycling peakers and flexible units much more frequently than was required in the 2016 Production Baseline.

Figure 49. RTD (5-Minute) Net Load Ramp Rate [MW/5-min], March Day

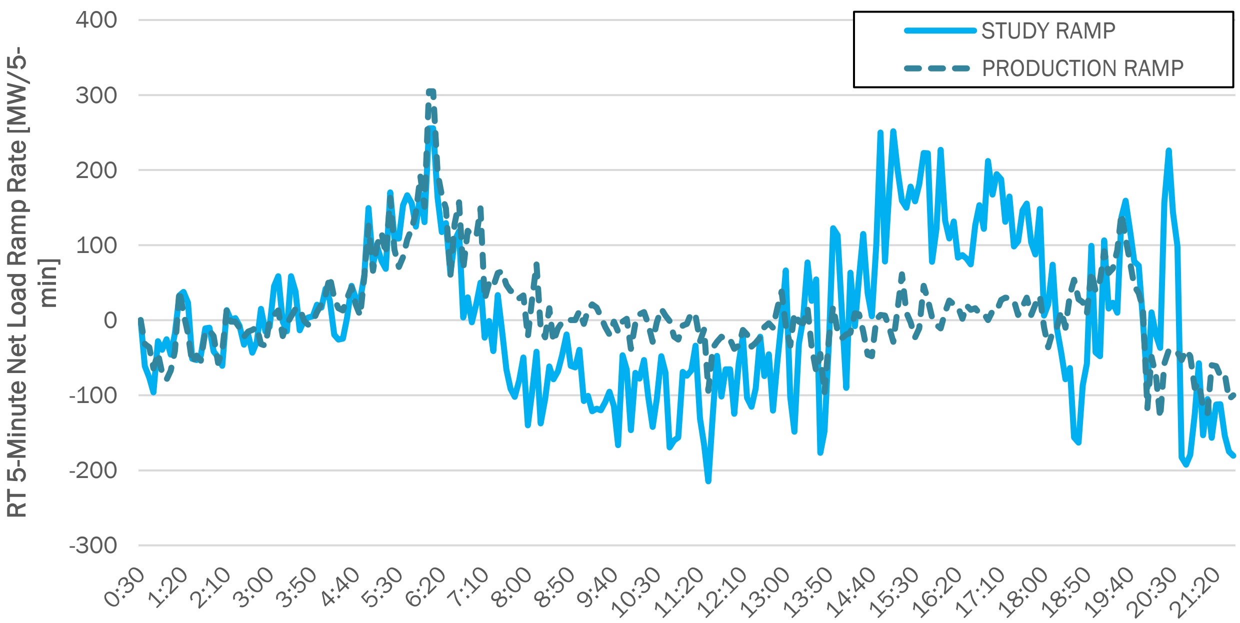


Figure 50: RTD (5-Minute) Net Load Ramp Rate [MW/5-min], July Day

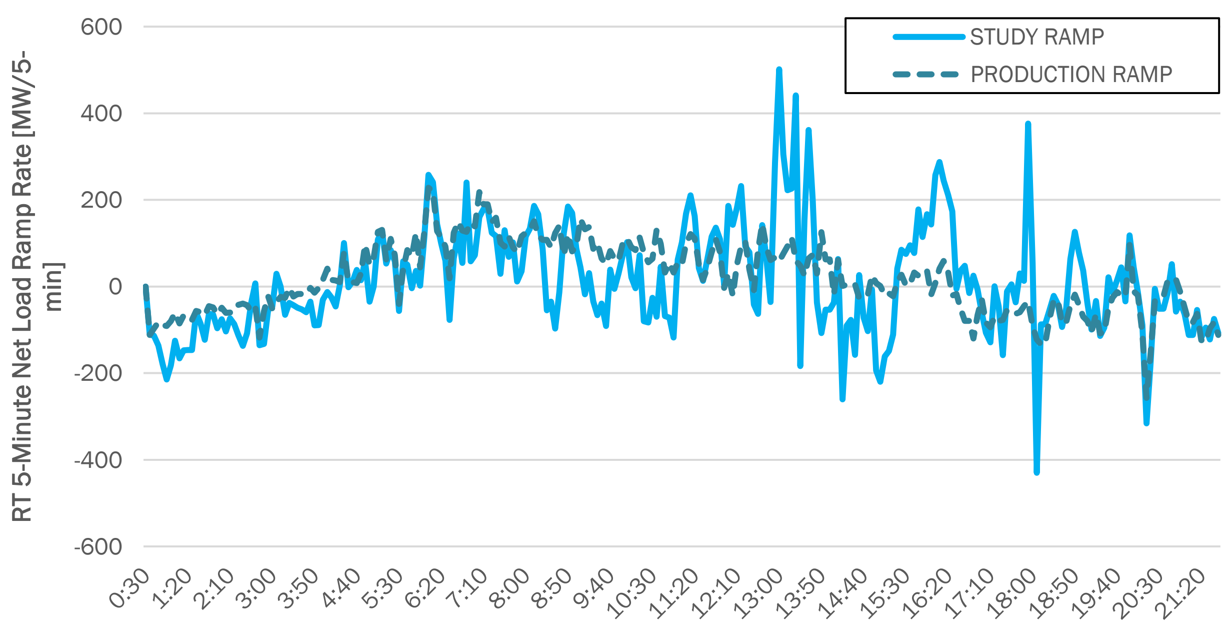


Figure 51: RTD (5-Minute) Net Load Ramp Rate [MW/5-min], November Day

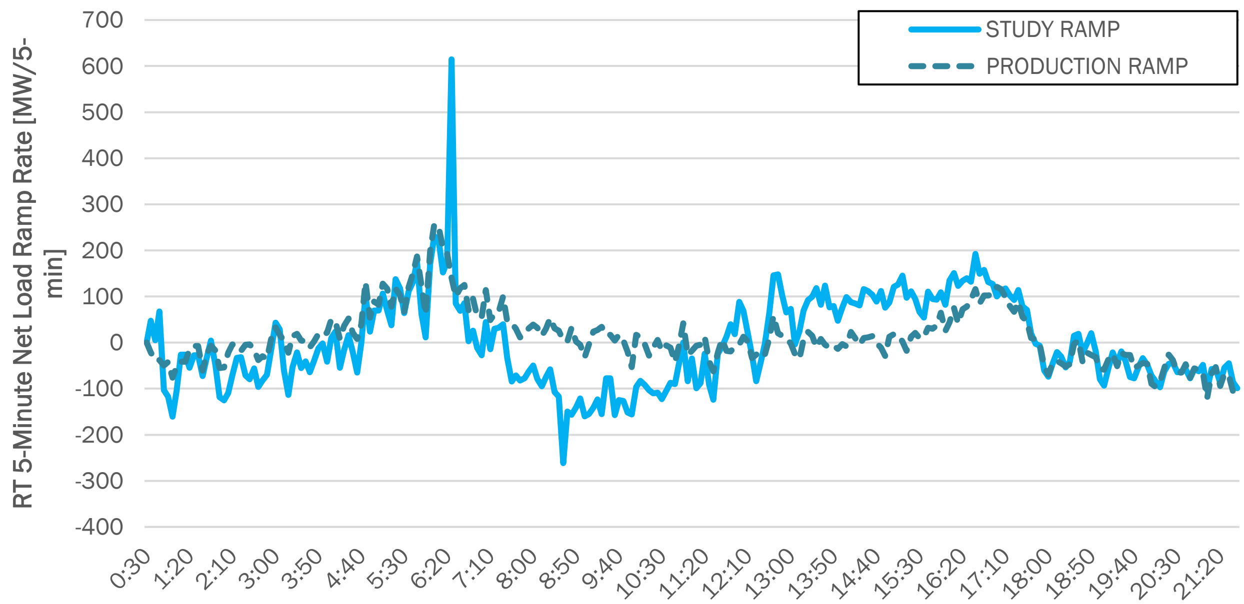


Figure 52 and Figure 53 illustrate how much the NYCA load moved on average during each real-time hour on the March day. On a five-minute basis, the net load ramp in the Market Study cases was significantly more volatile than it appears to be in the hourly charts. In the Production Baseline case, generation ramped up during the early morning and evening periods. Net load decreased at night and the generation was dispatched down. In the Market Study case, flexible generators were dispatched down to serve the reduced net load as front of the meter and behind the meter solar ramped up. In the evening, dispatchable generators were ramped back up to meet the evening peak load. Load ramp was more volatile in the Market Study. Average hourly load ramp charts for July and November are also provided in Figure 54, Figure 55, Figure 56, and Figure 58 . Increased volatility can be observed on both Market Study days.

Figure 52: Average Hourly Real Time Power System Ramp, Production Baseline, March Day

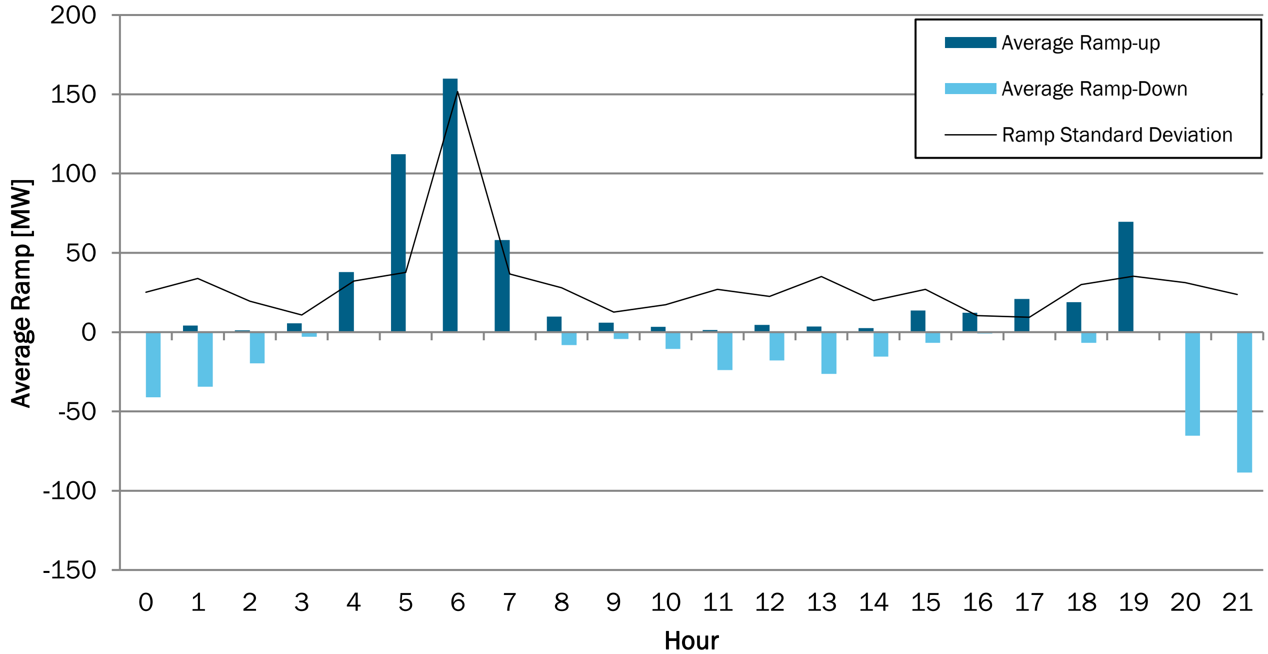


Figure 53: Average Hourly Real Time Power System Ramp, Market Study, March Day

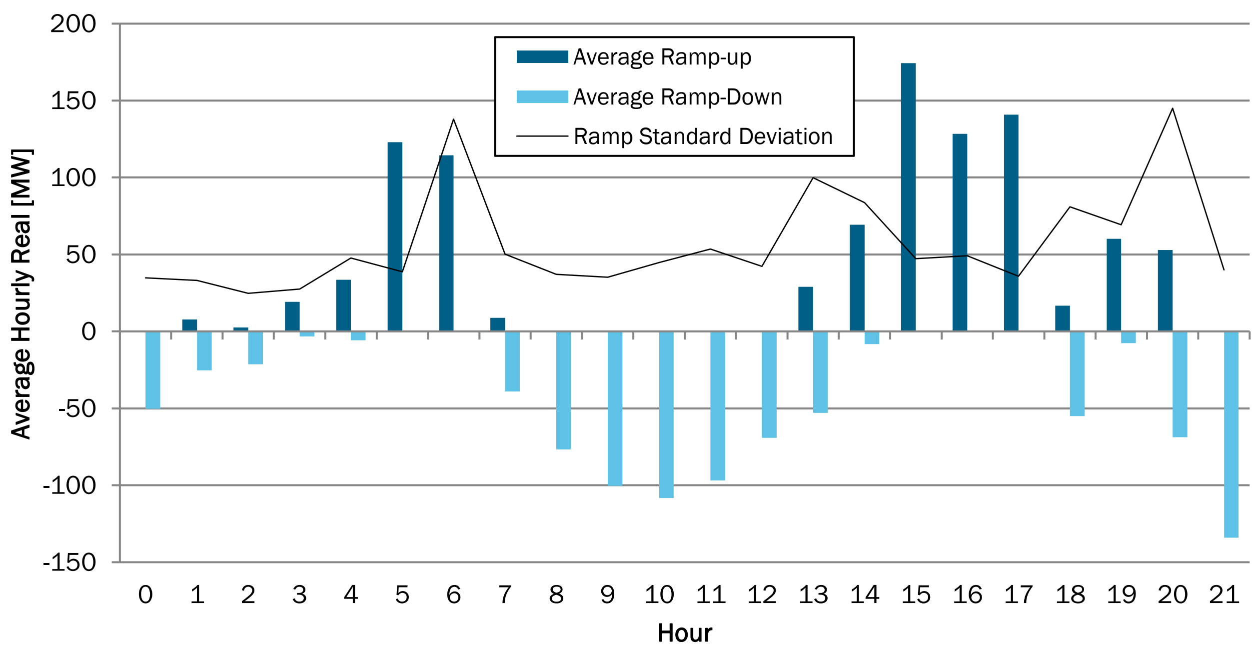


Figure 54: Average Hourly Real Time Power System Ramp, Production Baseline, July Day

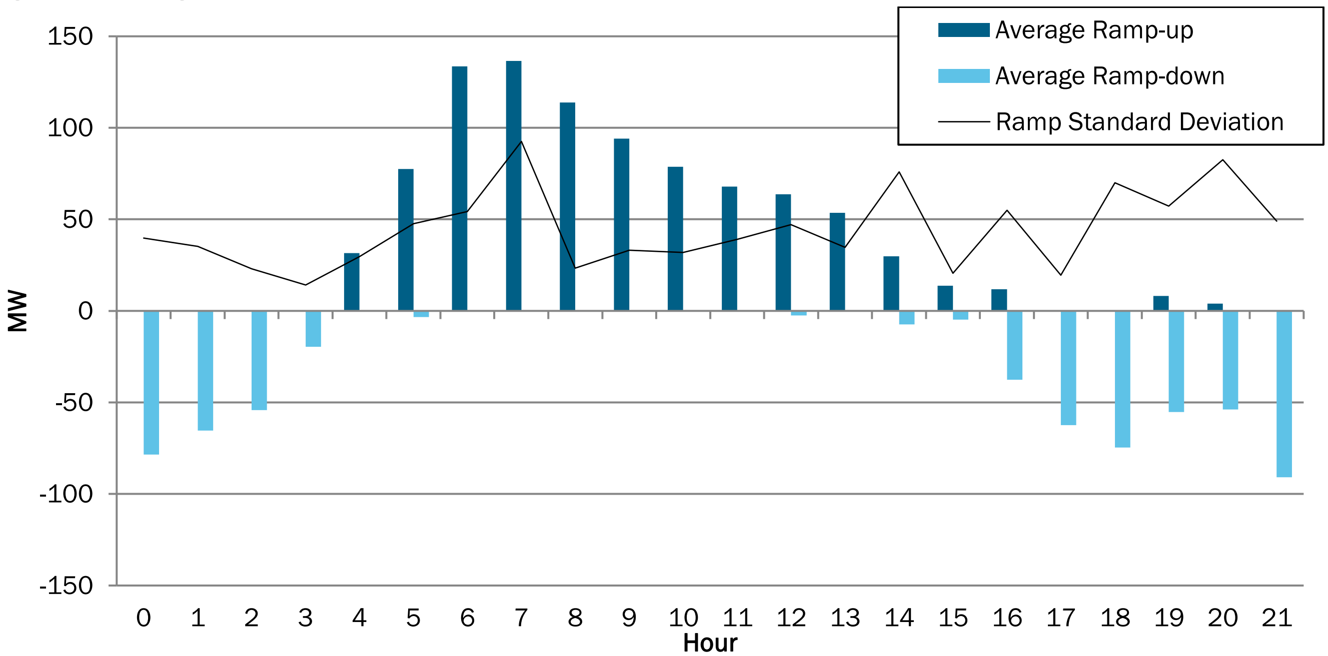


Figure 55: Average Hourly Real Time Power System Ramp, Market Study, July Day

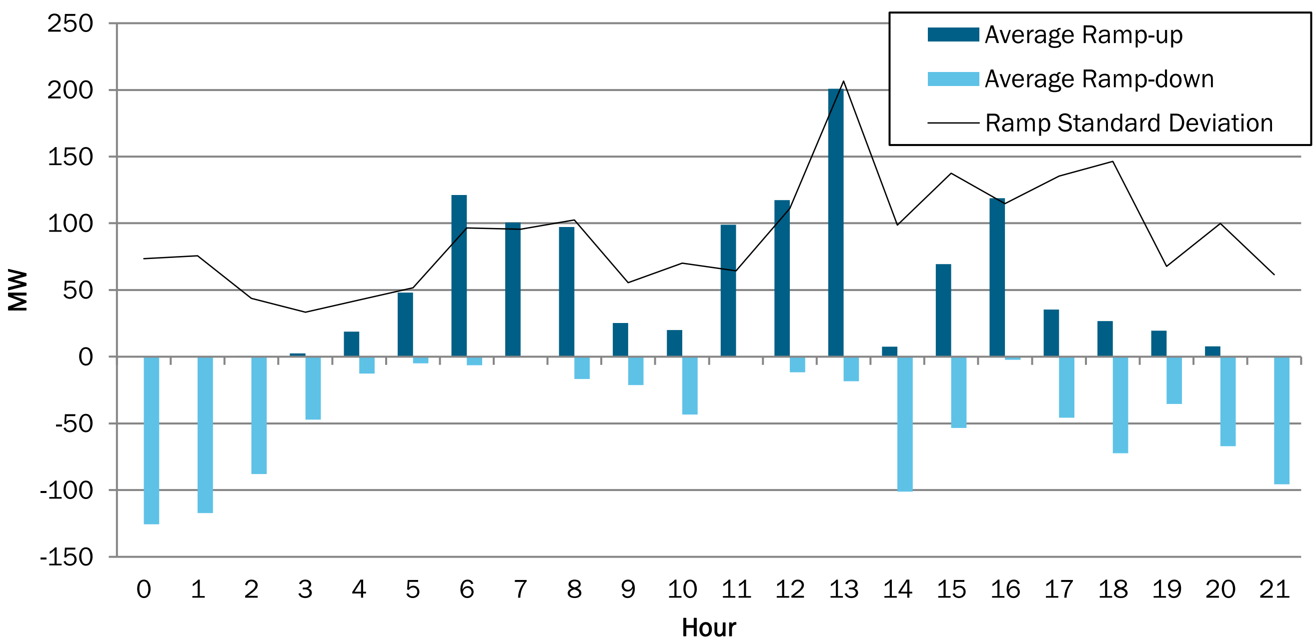


Figure 56: Average Hourly Real Time Power System Ramp, Production Baseline, November Day

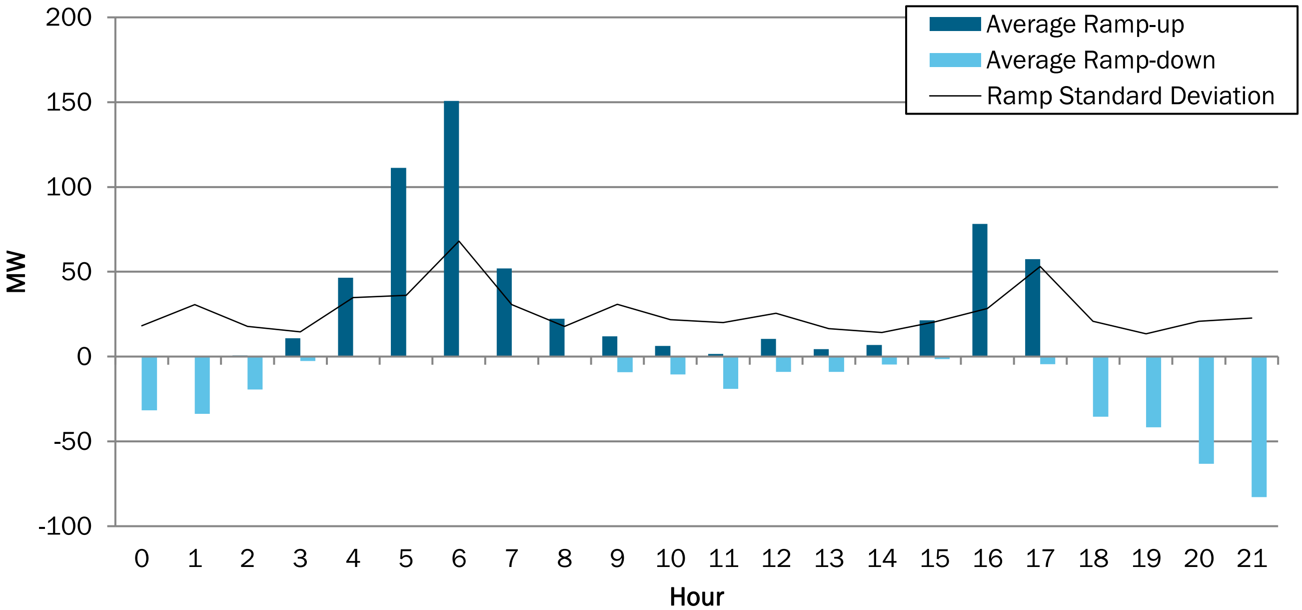
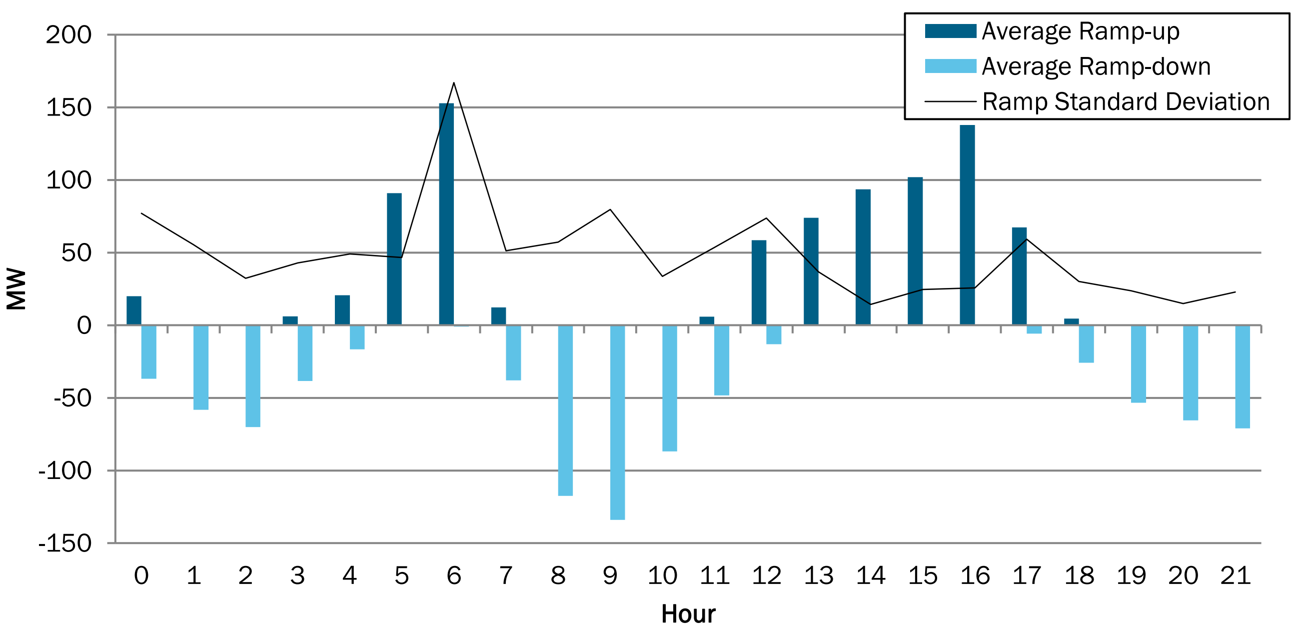


Figure 57: Average Hourly Real Time Power System Ramp, Market Study, November Day



Energy Market Prices

Energy Market clearing prices are provided in this section to help the reader understand market trends, rather than a prediction of future market outcomes. DAM prices are averages of the hourly LBMP's in the Eastern and Western Load Zones. Real-time prices are averages of the 5-minute RTD LBMP's in the Eastern and Western Load Zones. All prices are reported in dollars per megawatt-hour ($/MWh). Incremental Renewable resources were modeled as price sensitive at negative $47/MWh. A detailed discussion of study assumptions appears in Appendix A: Study Methodology.

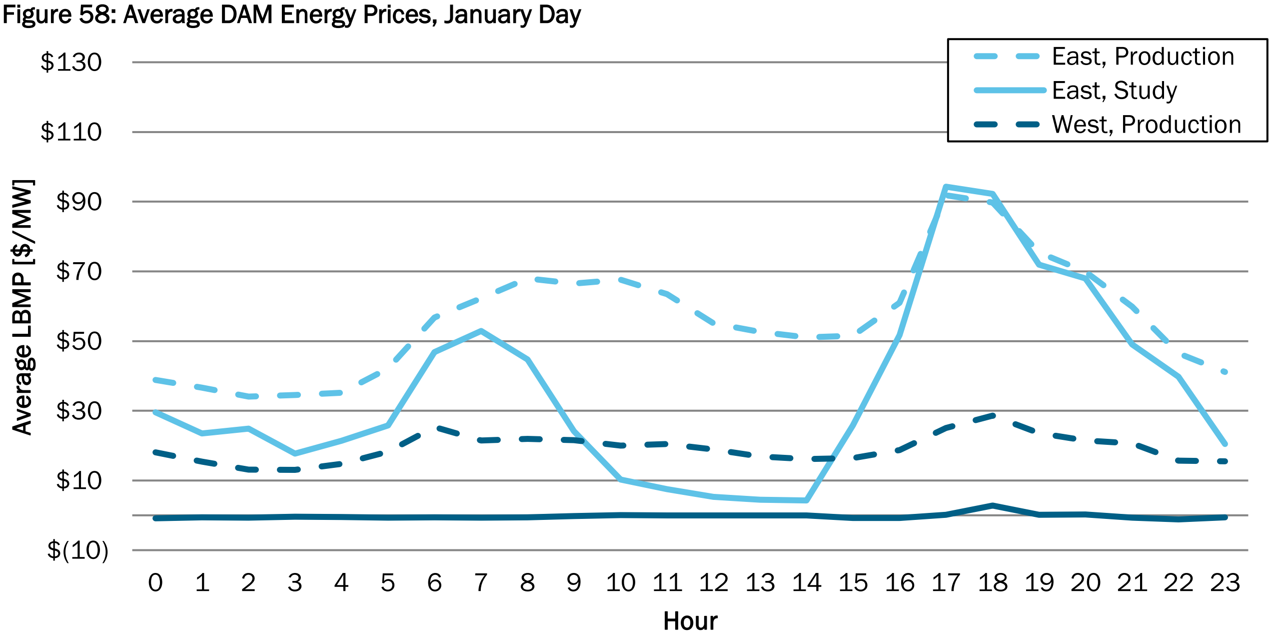
January Day

January 19th, 2016 was a winter peak day characterized by persistently strong wind and cold weather. Major transmission outages, including the UE1-7 Marcy-Edic 345 kV line and MMS1 Moses-Massena 230 kV line, limited the ability of power to flow from West to East.

DAM Energy Prices

In the Production Baseline day, high demand and natural gas prices yielded morning prices in the East between $40/MWh and $60/MWh. The average LBMP across the East climbed to $92/MWh during the evening. In the West, lower gas demand held prices around $20/MWh. In the Market Study, average prices in the East dropped to $4/MWh at midday before returning to 2016 levels as forecast solar output dropped off in the evening. In the West, persistently high forecast wind generation drove prices down to nearly $0/MWh for the entire day.

Figure 58: Average DAM Energy Prices, January Day



Real-Time Prices

Real-time results are not available for the January day. A discussion of the January Real-Time Market Study case appears in Appendix B: Detailed Study Results & Discussion, The existing transmission system limits the amount of energy that can flow across New York at any given time. A significant bottleneck, referred to as Central East, persistently forms around a group of transmission facilities. The Market Study reports average Locational Marginal Based Prices (LBMPs) for the load zones West and East of this constraint, where "West" refers to Load Zones A-E, and "East" refers to Load Zones F-K. The severity of congestion along Central East is evident in price separation between West and East.

Relative price differences and trends reported between West and East may be indicative of future NY Power System needs, but the Market Study clearing price values are not predictive of future clearing prices. For example, prices at or near negative $47/MWh appeared in intervals when modeled renewable resources were on the margin. Negative $47/MWh was chosen as the offer floor for Incremental Renewables because that is the point at which qualifying renewables are price sensitive today. How this value may change in the future is difficult to determine, but the conditions that arose in the Market Study are still relevant.

January Real Time Market Study Day

March Day

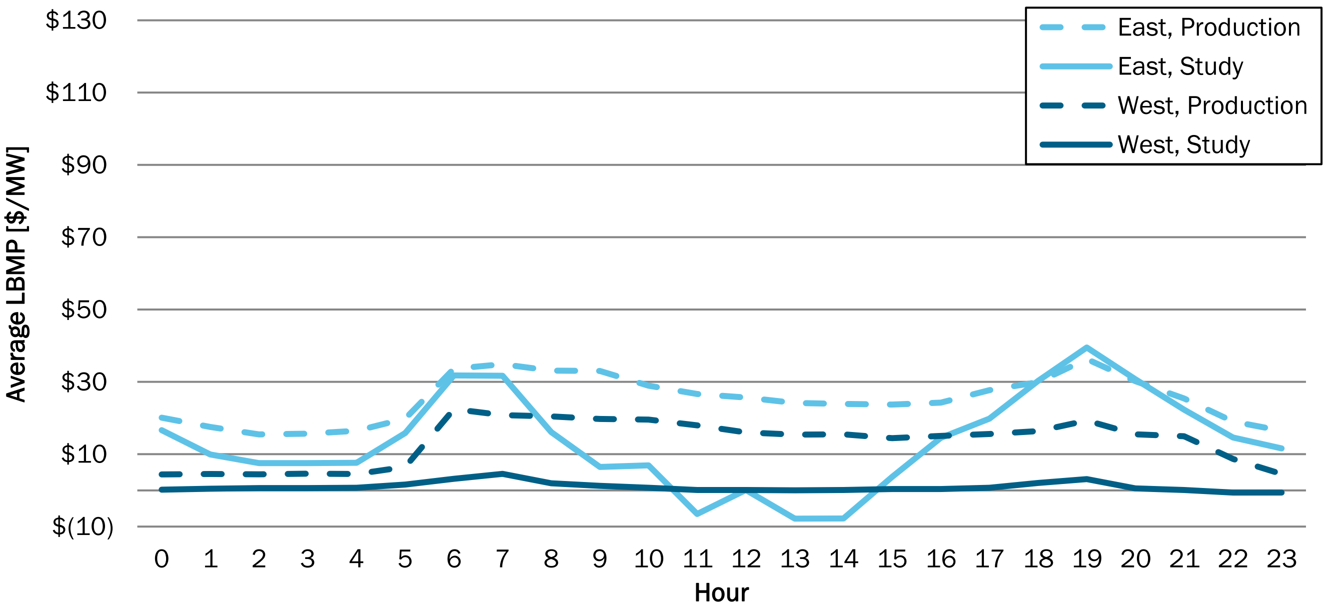
March 22nd, 2016 was characterized by low energy demand. The weather was mild and natural gas prices were relatively low. Indian Point 2, a large (~1,000 MW) nuclear generator in the East was out of service for refueling. The ~1,000 MW reduction of generating capacity was included in the Production Baseline and carried over into the March Market Study day.[58]

DAM Prices

During the Production Baseline day, prices in the East averaged only $25/MWh, staying in the range of $15 to $36/MWh. Prices in the West were in the range of $4 to $22/MWh. In the Market Study, Western prices averaged near $0/MWh for the entire day. Eastern prices fell below zero around midday and renewable generation modeled in Long Island caused prices to clear at the negative $47/MWh floor for Long Island.

[58] Indian Point 2 and 3 were in service for the other Market Study days.

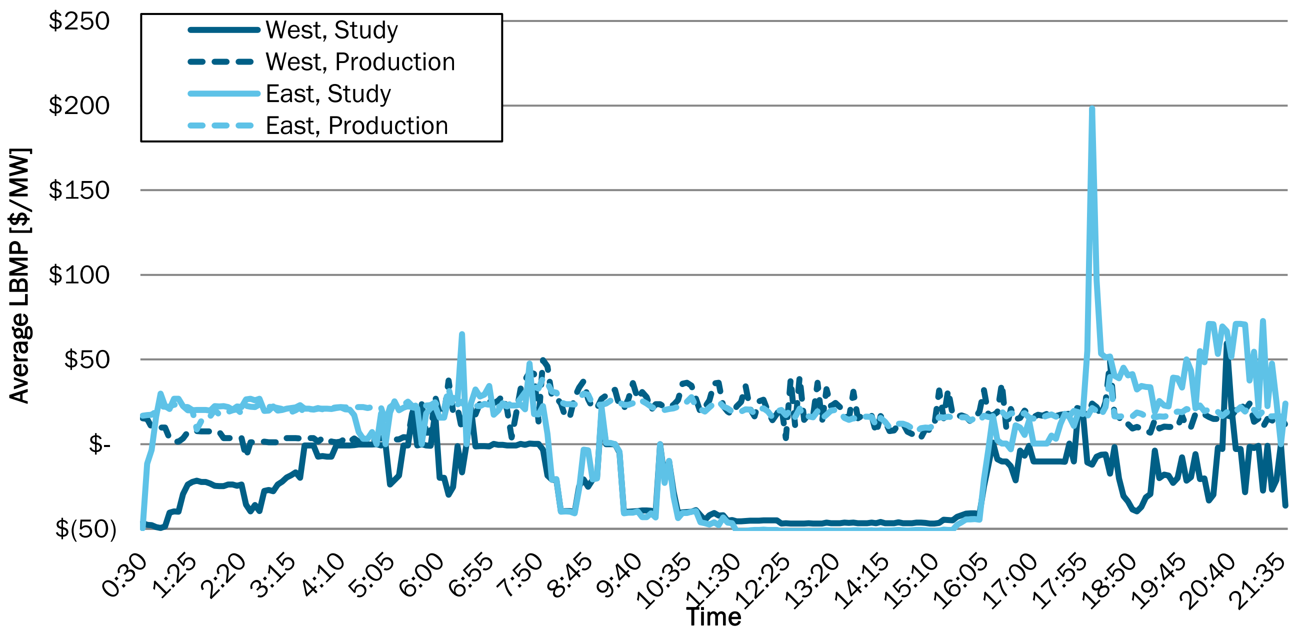
Figure 59: Average DAM Energy Prices, March Day



Real-Time Energy Prices

In the real-time Production Baseline case, prices were low all day. In the Market Study, prices cleared below $0/MWh for most of the day in the West. Real-time prices cleared at negative $47/MWh in the East, near the assumed point of price sensitivity for added renewable resources, while solar production was at its peak. Eastern prices rose again during the evening load pick-up period as solar production dropped off. The late price spike in the Market Study indicates that additional fast-start resources were needed to meet the increased evening load.

Figure 60: Average RTD Energy Prices, March Day



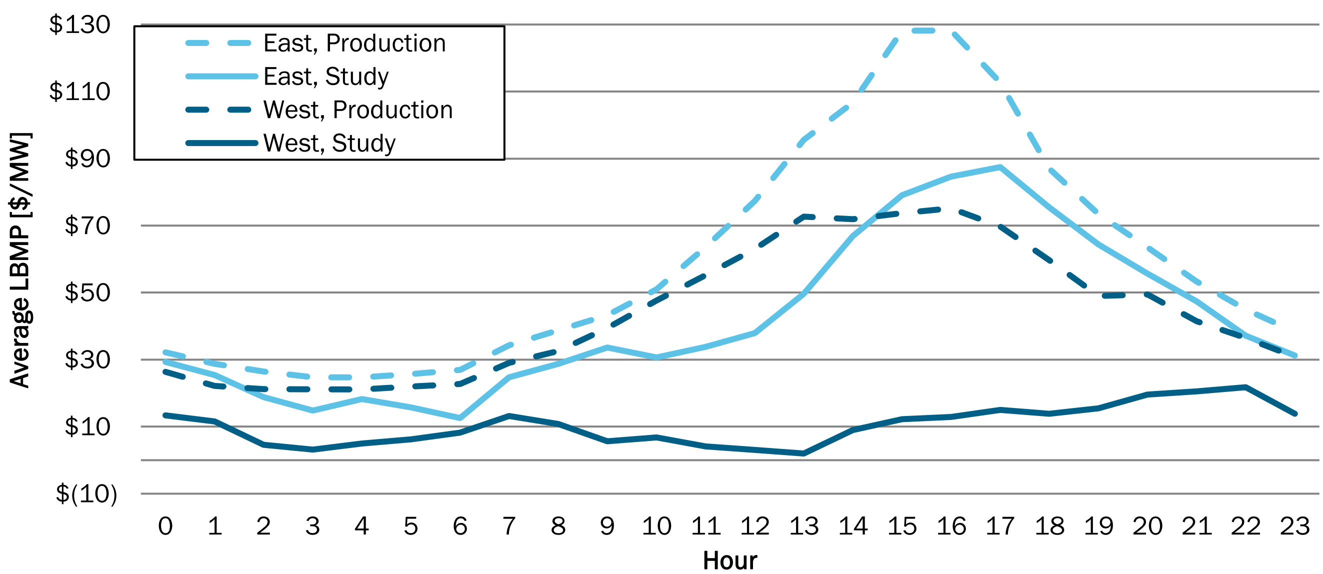
July Day

July 25th, 2016 was a hot summer day with high demand. A thunderstorm crossed the State on this day and natural gas prices were relatively low.

DAM Energy Prices

In the Production Baseline case, East prices rose to $128/MWh, while West prices peaked around $70/MWh. In the Market Study, prices peaked during the afternoon despite significant solar generation in the Day-Ahead forecast. While the Incremental Renewables did not flatten the net load profile, East prices were significantly reduced during peak hours, settling below $90/MWh. Forecast solar output in the Market Study shifted the peak price hour from Hour Beginning 4 to Hour Beginning 1617. In the West, the solar forecast also reduced peak energy prices, which cleared roughly $50/MWh lower in the Market Study than in the Production Baseline case.

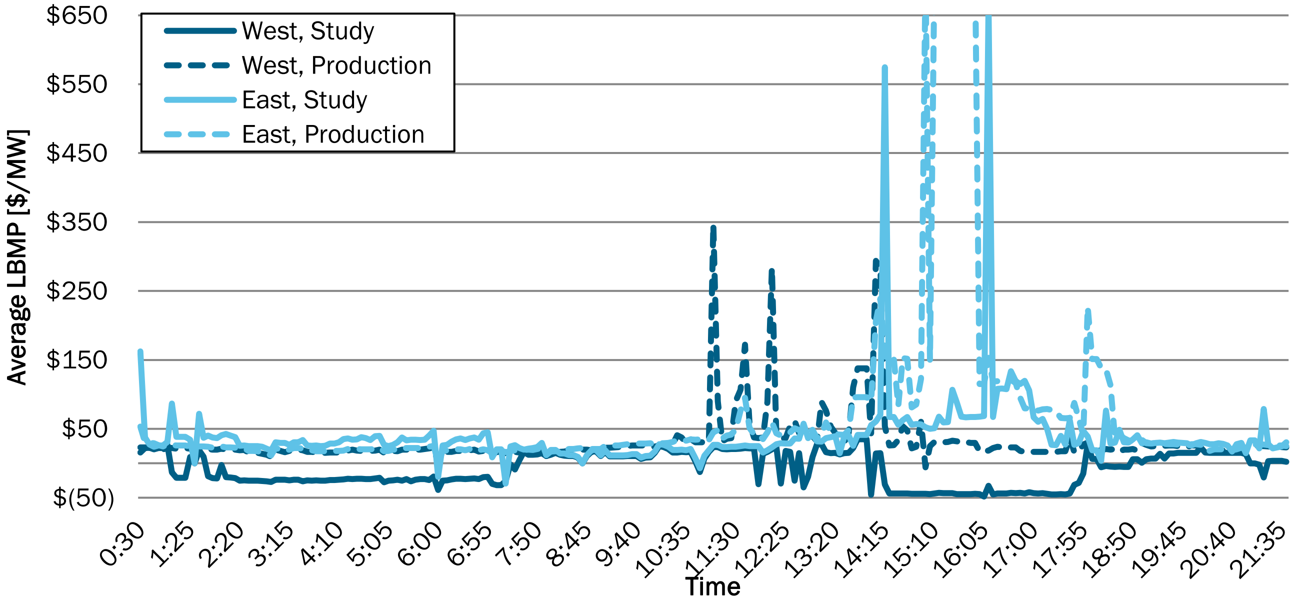
Figure 61: Average DAM Energy Prices, July Day



Real-Time Energy Prices

The Production Baseline day was characterized by several severe price spikes related to thunderstorm activity. At the daily peak, prices in the East reached nearly $900/MWh. While price spikes were still observed in the Market Study simulation, their frequency and magnitude were reduced. The peak price was $667.55/MWh and prices were only above $250/MWh in two intervals. Modeled solar forecast error may have exacerbated Market Study price spikes. Notably, morning prices in the East were higher in the Market Study. Prices were negative in the West for much of the Market Study day because supply from Incremental Renewable resources exceeded energy demand, even during peak hours.

Figure 62: Average RTD Energy Prices, July Day



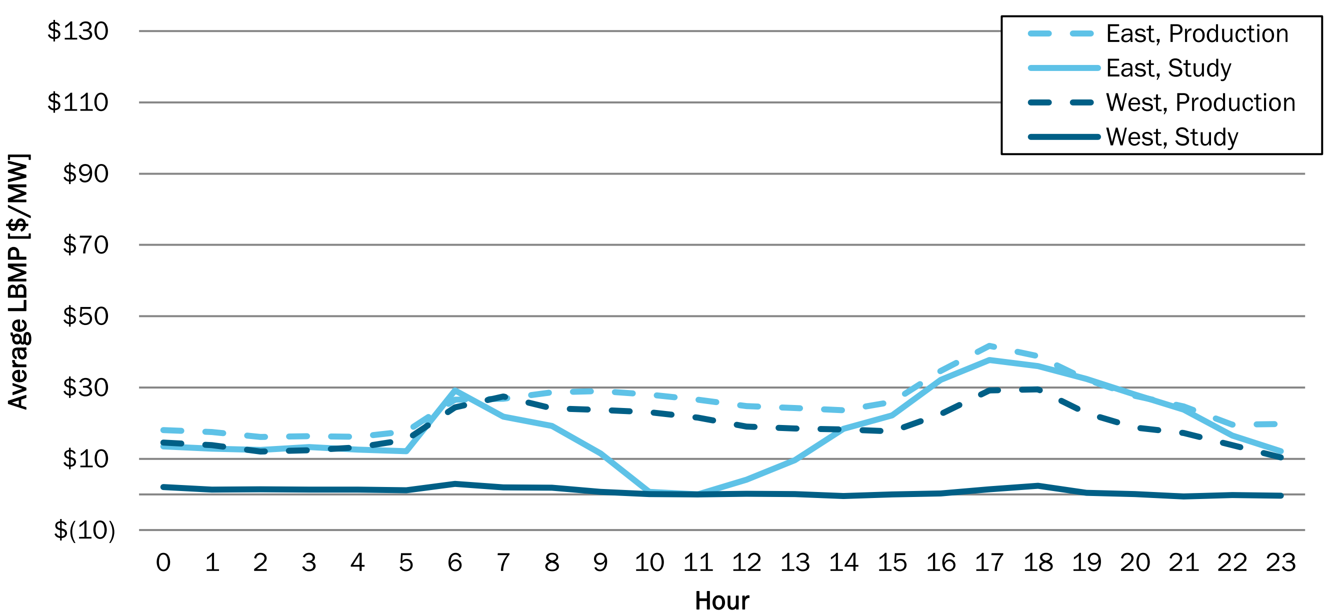
November Day

November 10, 2016 was a low-load shoulder day with high winds.

DAM Energy Prices

In the East, Production Baseline prices hovered around $30/MWh for most of the day, and the Market Study tracked this trend during the early morning and late afternoon/ evening. Production Baseline and Market Study price separation was observed from hour beginning seven (7) to hour beginning fourteen (14), when Market Study prices plummeted to $0/MWh. During the morning and evening hours, there was little to no forecast solar generation, which drove prices in the Market Study closer to Production Baseline prices. West and East prices were similar early in the Production Baseline day until forecast wind generation picked up, driving West prices lower. In the Market Study, West prices hovered near $0/MWh for the entire day.

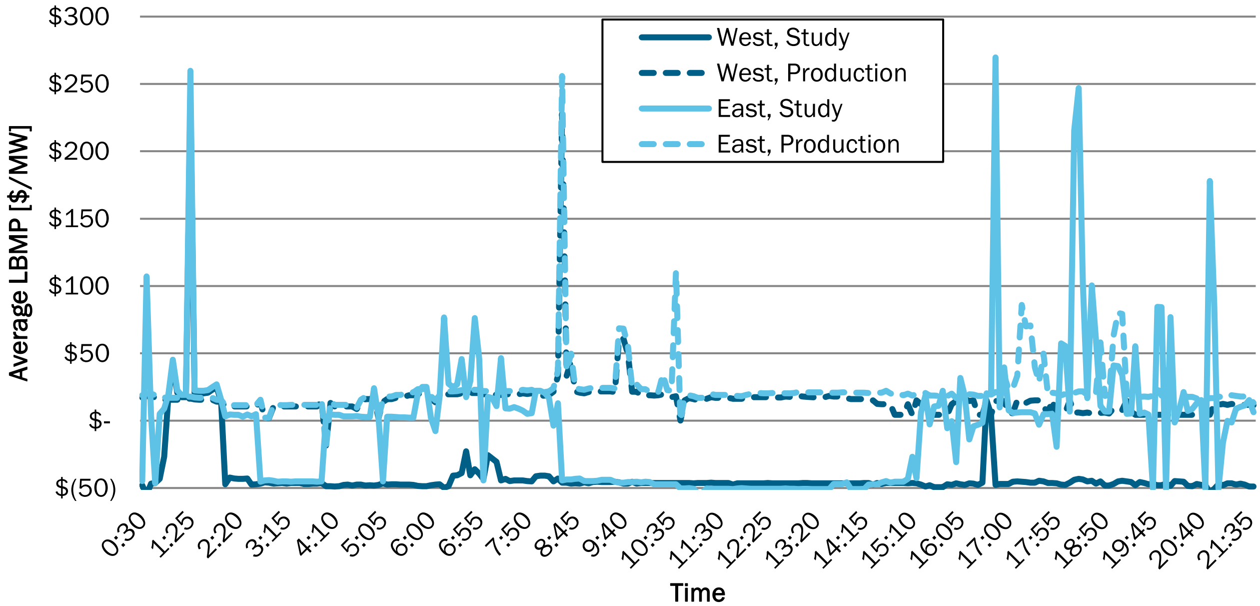
Figure 63: Average DAM Energy Prices, November Day



Real-Time Energy Prices

Real-time prices in the Market Study stayed at or below the marginal value assigned to Incremental Renewables (negative $47/MWh) in the West all day and during most daylight hours in the East. East prices were higher during the morning and evening, when solar output was lower. Because fewer flexible generators were committed in the DAM Market Study, East prices spiked during intervals when the real-time solution tools were not prepared for sudden increases in net load.

Figure 64: Average RTD Energy Prices, November Day



Unit Commitment and Dispatch

Incremental Renewable resources modeled in the Market Study shifted existing resources off the margin. The following section summarizes changes in the commitment and dispatch of those resources. Aggregate changes in Day-Ahead commitment and Real-Time Dispatch from Production Baseline to Market Study cases are plotted by resource type. Resource classes that were economically evaluated are shown. Price-takers, such as solar energy and landfill gas generators, were excluded from this analysis. Incremental Renewable resources were also excluded because they did not exist in the Production Baseline cases and thus have no basis for comparison. Units are grouped according to the definitions established in Table III-2 of the *2017 Load and Capacity Data Report*[59]. For this report, Combustion Turbines, Internal Combustion and Jet Engines are grouped together and referred to as “peakers”, because they are often

59 2017 Load and Capacity Data Report: https://www.nyiso.com/public/webdocs/markets_operations/services/planning/Documents_and_Resources/Planning_Data_and_Reference_Docs/Data_and_Reference_Docs/2017_Load_and_Capacity_Data_Report.pdf

deployed to meet peak energy demand.

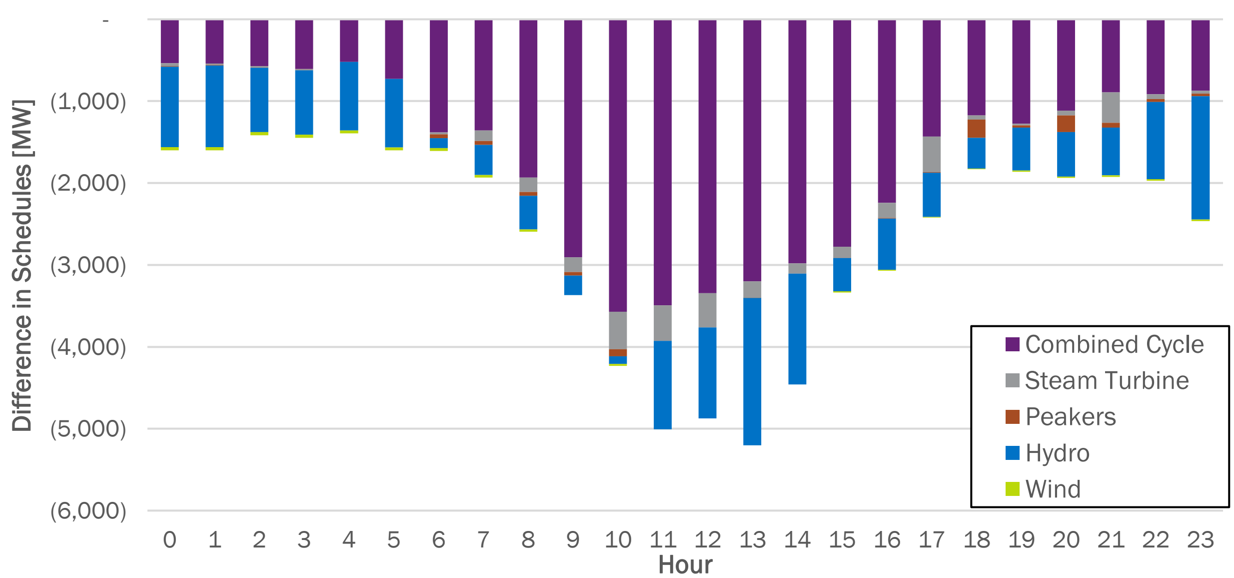
Across all DAM and RTM Market Study cases, net load decreased because more behind the meter renewable resources were available. Flexible units, such as combined cycle and conventional hydroelectric plants, were scheduled and dispatched to provide energy less frequently in Day-Ahead and real-time.

Figure 65: Change in RT Share of Total Daily Output from Flexible Units (Market Study – Production Baseline) [%]

Study Day	March	July	Nov
% Variation	-41%	-27%	-41%

On an hourly basis, the change in DAM energy schedules by unit type was related to the change in the Net Load profile. This trend is illustrated in Figure 66.

Figure 66: Hourly Change in Day Ahead Schedules, March



Existing hydroelectric units were scheduled to provide less energy on the January, March, and November Market Study days. Hydroelectric units are primarily sited in Western and Northern New York, where the existing transmission system limits the ability to move low-cost power to load centers in the East. Despite peak winter demand on the January day, hydroelectric schedules remained depressed in the DAM Market Study. Significant outages of 230 and 345 kV transmission lines in the West caused hydroelectric plants to compete with renewable resources in the same region. While neither have fuel costs, Incremental Renewables were on the margin because they were modeled with an offer floor of negative $47/MWh.

Demand was high on the July day. In the RTM Market Study case, combined cycle and steam units were called on to provide more Operating Reserves than in the Production Baseline case. In all other Market Study cases, they were scheduled to provide significantly less energy and ancillary services. Existing steam units are heavily concentrated near New York City, downstream of the most significant transmission constraints. These units are typically less flexible than combined cycle units and less willing to deviate from their Day-Ahead schedules.

On the lower load March and November Market Study days, peakers were committed and dispatched more often than on the Production Baseline days. On the November day, this was correlated with the evening load pickup and the fact that fewer combined cycle units were online. Conversely, fewer peakers were committed on the July Market Study day because more flexible resources were online.

Certain wind generators offered into the DAM during the Production Baseline days[60]. Their Day-Ahead schedules were reduced in the Market Study. In real-time, existing wind was dispatched less in the Market Study, most notably on the November day, which was characterized by high winds and low load. Both existing and modeled wind turbines were curtailed on that day.

[60] Intermittent renewables are not required to offer into the DAM unless they supply capacity. See Section 5.12.11.4 of the NYISO Market Administration and Control Area Services Tariff (MST): https://nyisoviewer.etariff.biz/ViewerDocLibrary//MasterTariffs/9TariffSections/MST%205.12%20FID1207%20wo1065%201183%20clean_18172.pdf

Figure 67: Total Day-Ahead Energy Schedule by Unit Type [MWh] (Market Study-Production Baseline), January Day

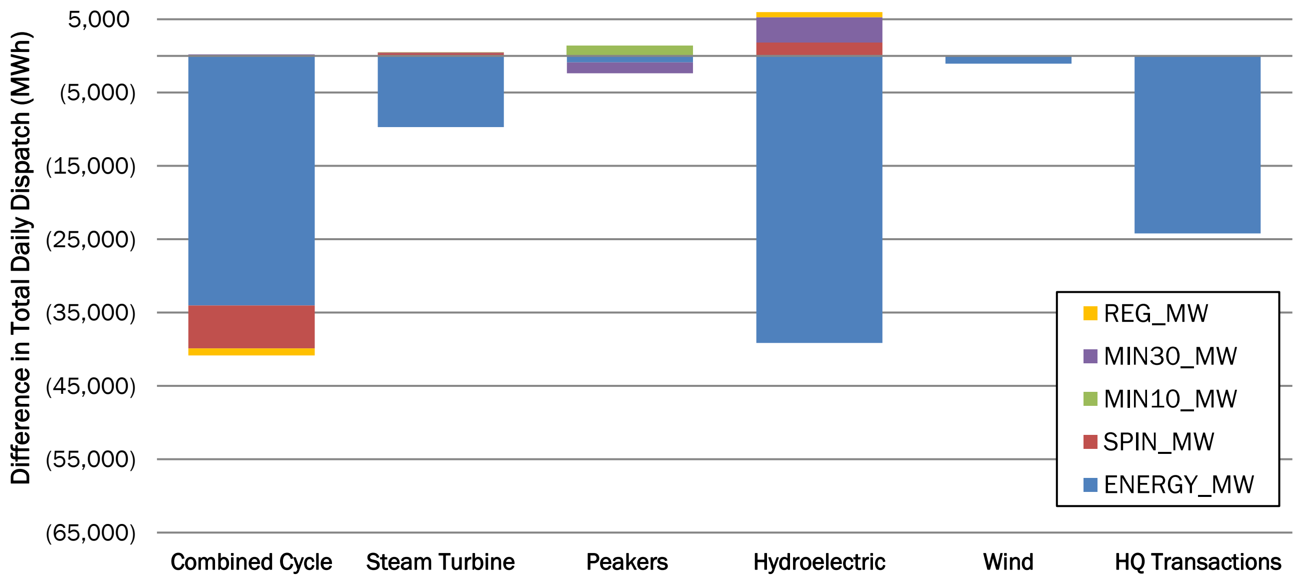


Figure 68: Total Day-Ahead Energy Schedule by Unit Type [MWh] (Market Study-Production Baseline), March Day

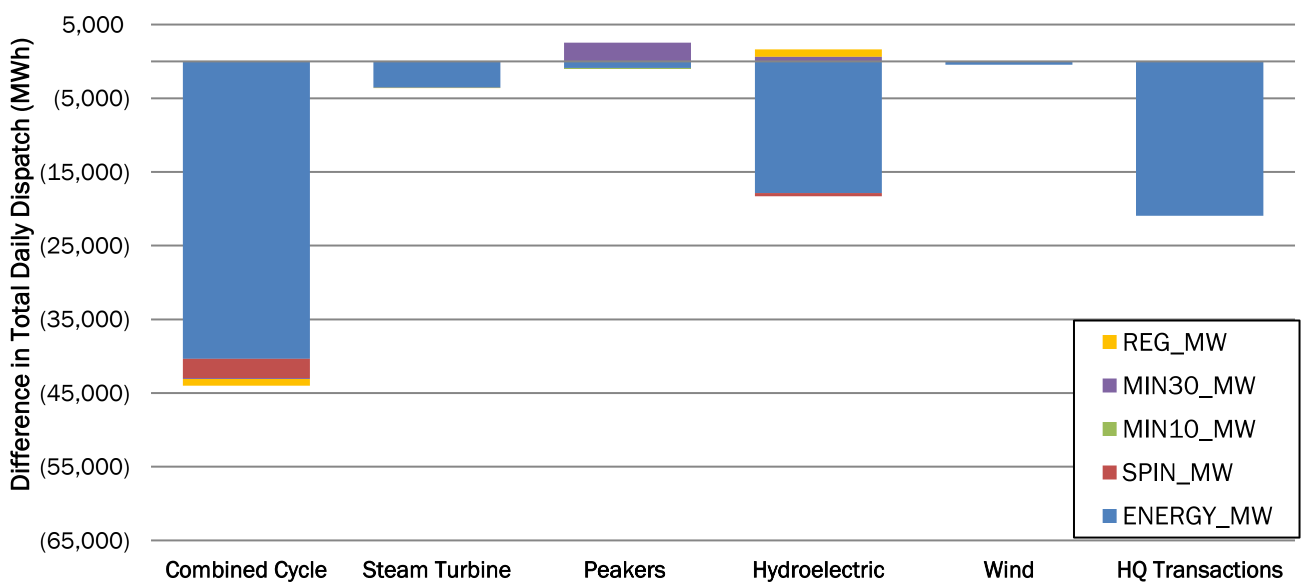


Figure 69: Total Day-Ahead Energy Schedules by Unit Type [MWh] (Market Study- Production Baseline), July Day

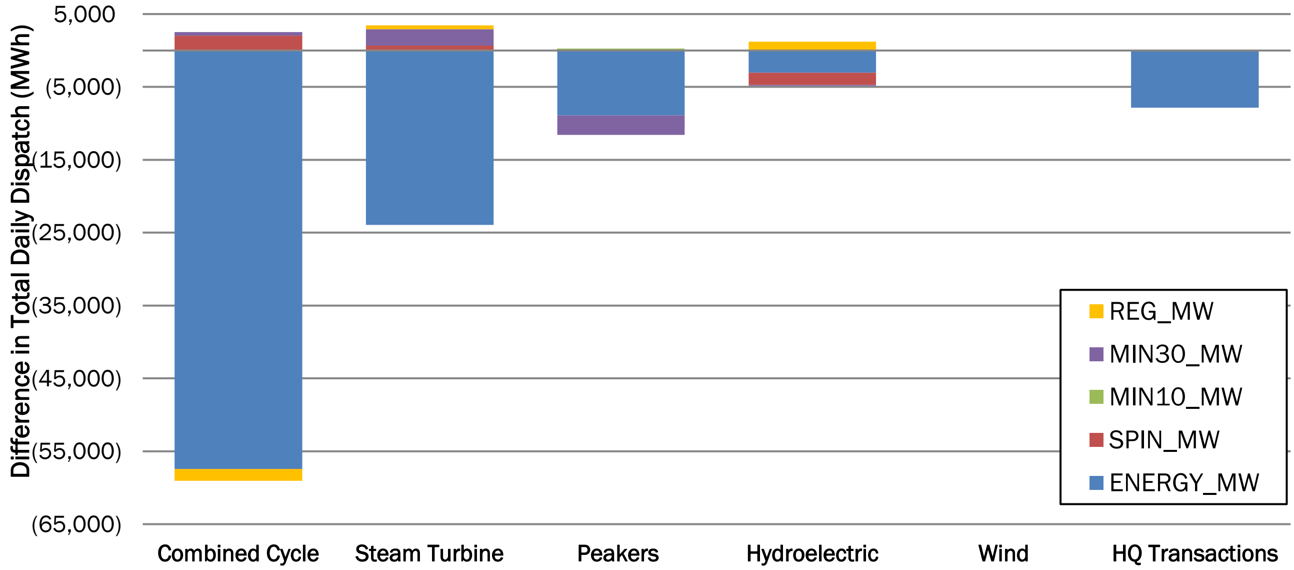


Figure 70: Total Day-Ahead Energy Schedules by Unit Type [MWh] (Market Study- Production Baseline), November Day

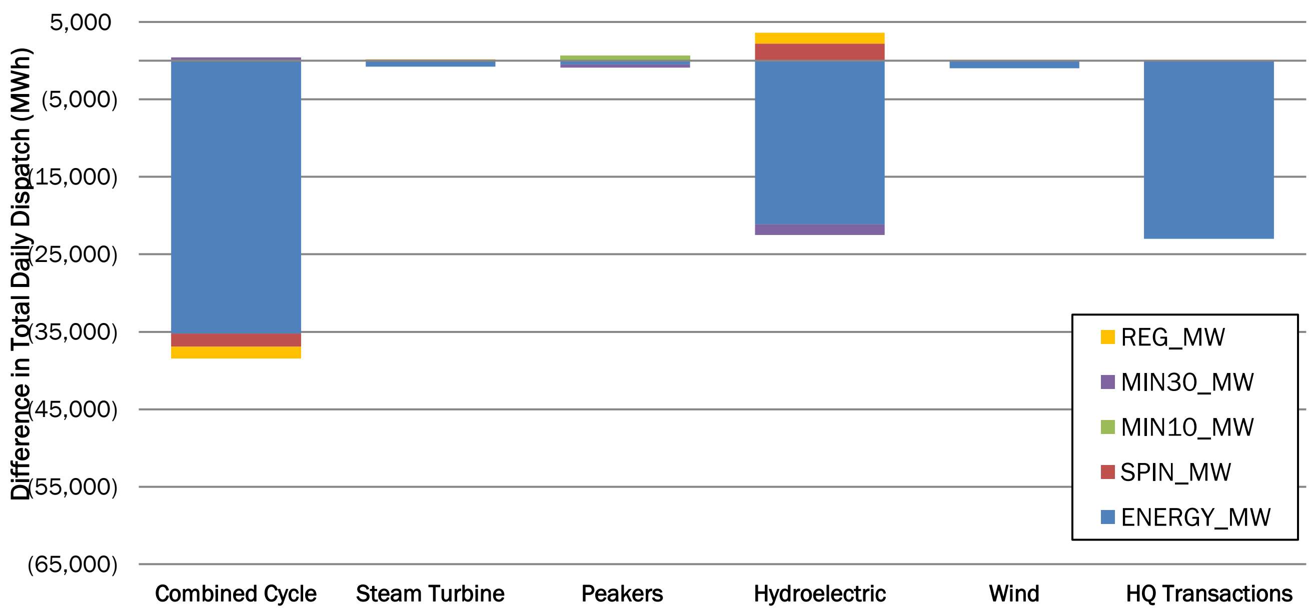


Figure 71: Real-time Unit Dispatch [MWh] (Market Study- Production Baseline), March

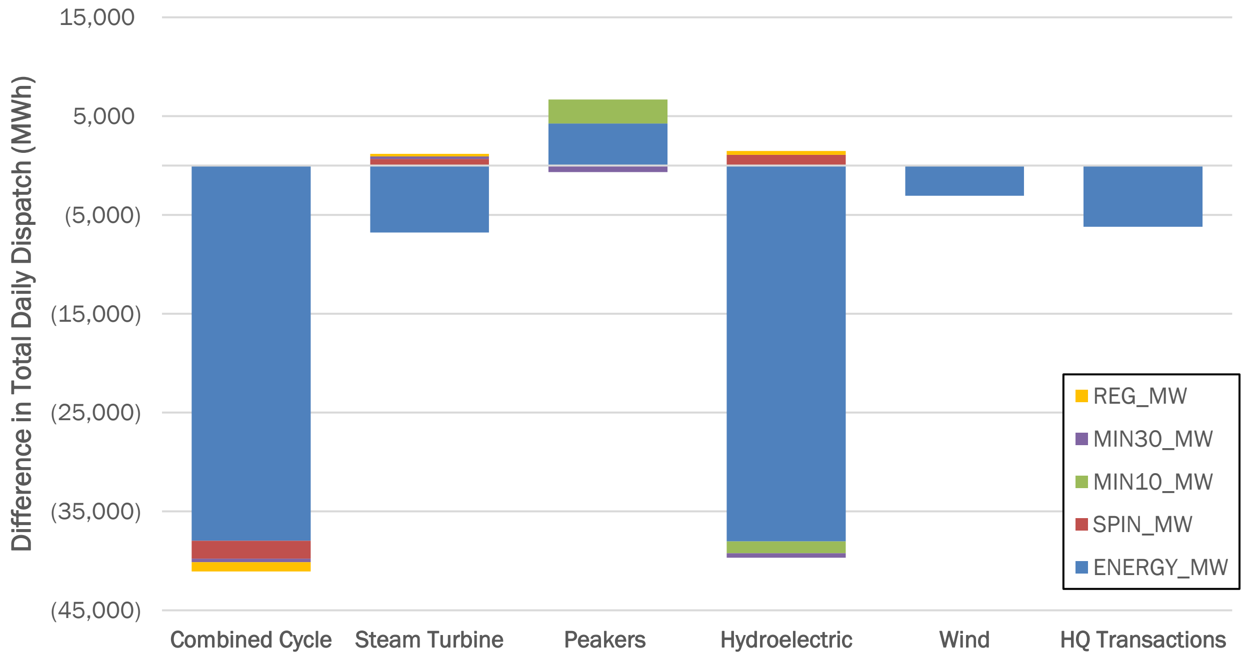


Figure 72: Real-time Unit Dispatch [MWh] (Market Study- Production Baseline), July

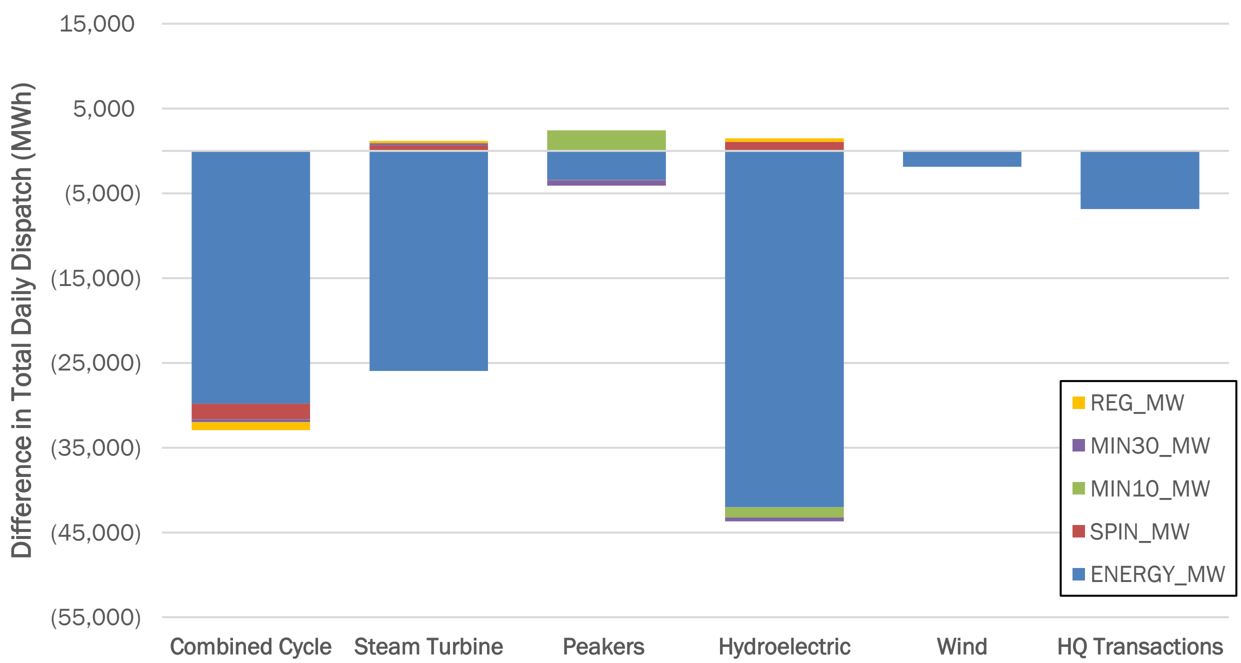
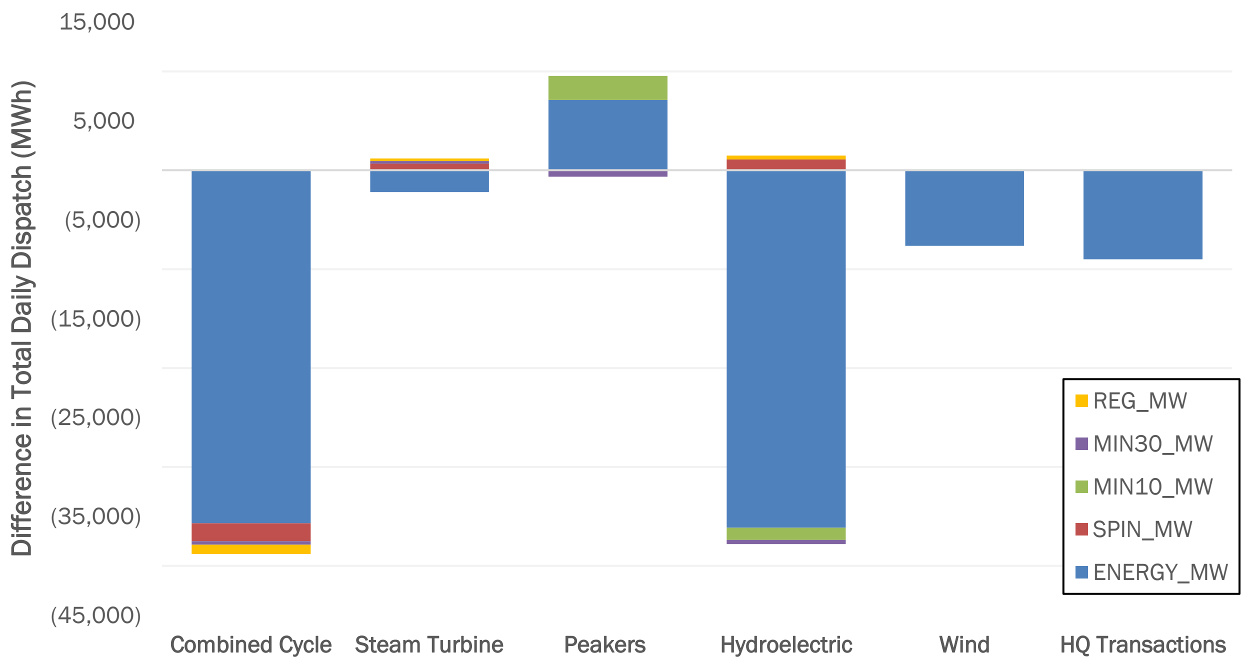


Figure 73: Real-time Unit Dispatch [MWh] (Market Study- Production Baseline), November



Generator Cycling

Existing generators were cycled more frequently on the Market Study days. Figure 74 provides the number of real-time starts by unit type for each case, and Figure 75 expresses the relative increase of total cycles per day as the ratio of cycles per Market Study case to cycles per Production Baseline case. The increase in cycles was least apparent on the July Market Study day, when load was high and most generators remained on during peak solar hours.

Figure 74: Starts per Day in Real Time by Unit Type

Resource Type	Production Baseline			Market Study		
	March	July	November	March	July	November
Combined Cycle	9	18	6	23	30	20
Peakers	34	116	26	49	127	85
Hydroelectric	2	6	4	7	13	12

Figure 75: Ratio of Real-Time Starts per Day in the Market Study to Production Baseline (RTC Committed Units)

Resource Type	March	July	Nov
Combined Cycle	2.2	1.6	2.7
Peakers	1.4	1.1	3.3
Hydroelectric	3.5	2.2	3.0

In general, the increase in cycles was most pronounced during afternoon and evening hours, between hour beginning fifteen (15) and twenty (20).

Figure 76: Change in Generator Starts, March (Market Study – Production Baseline)

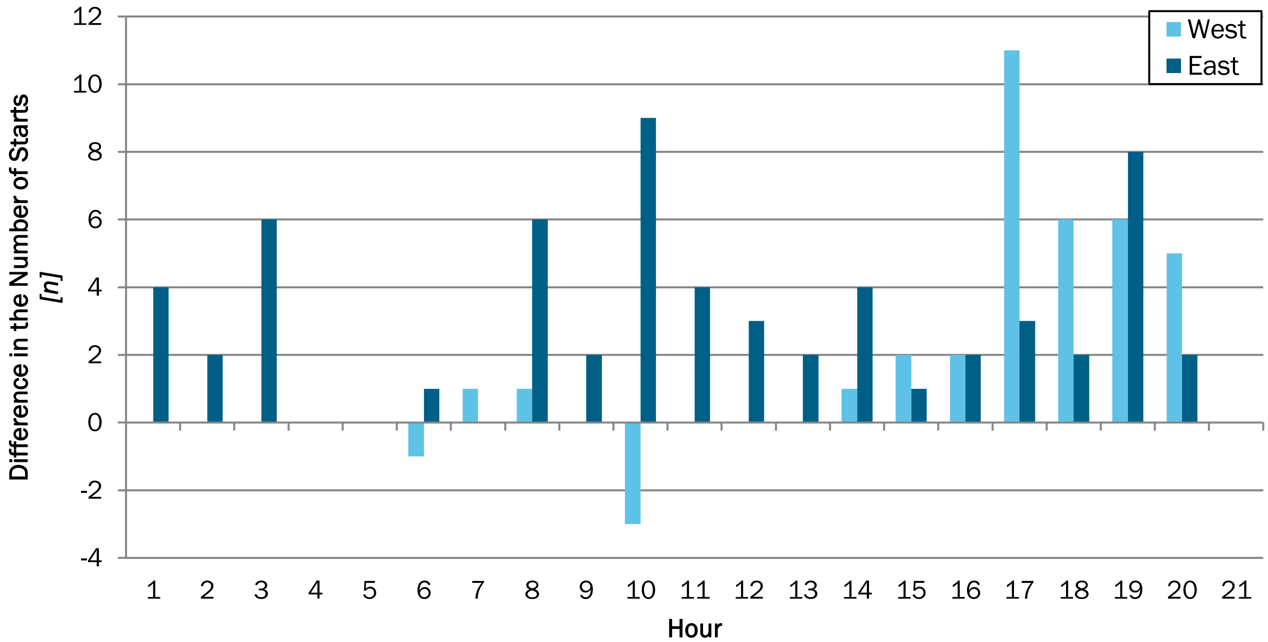


Figure 77: Change in Generator Starts, July (Market Study – Production Baseline)

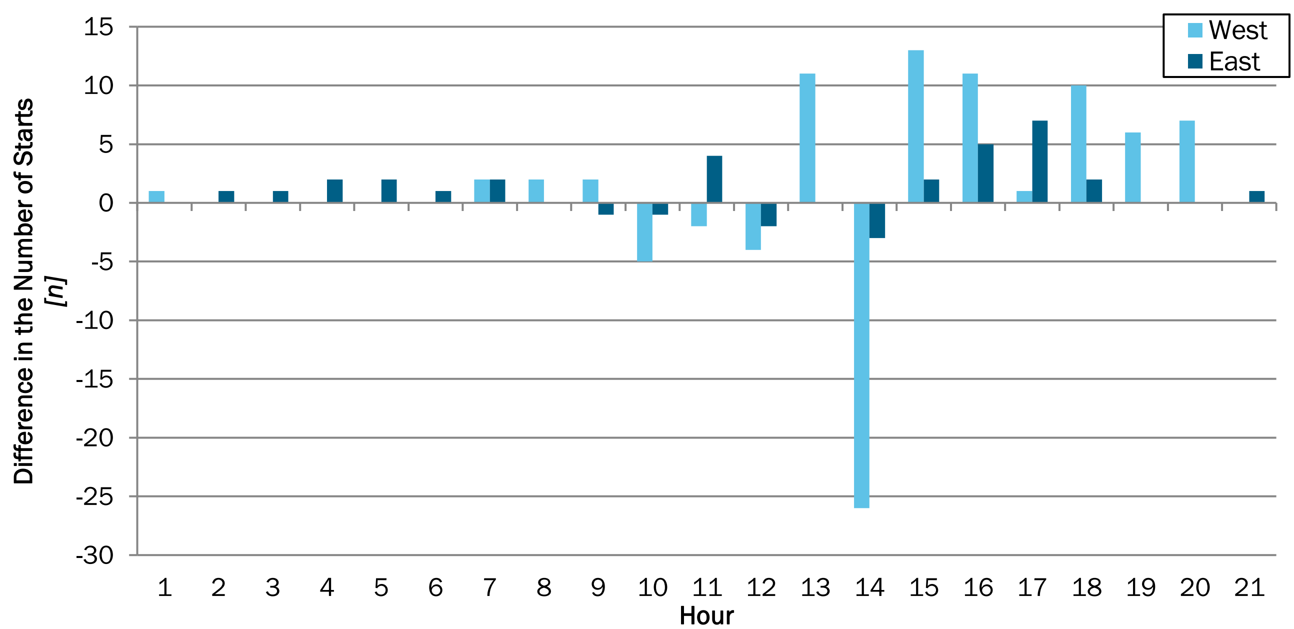
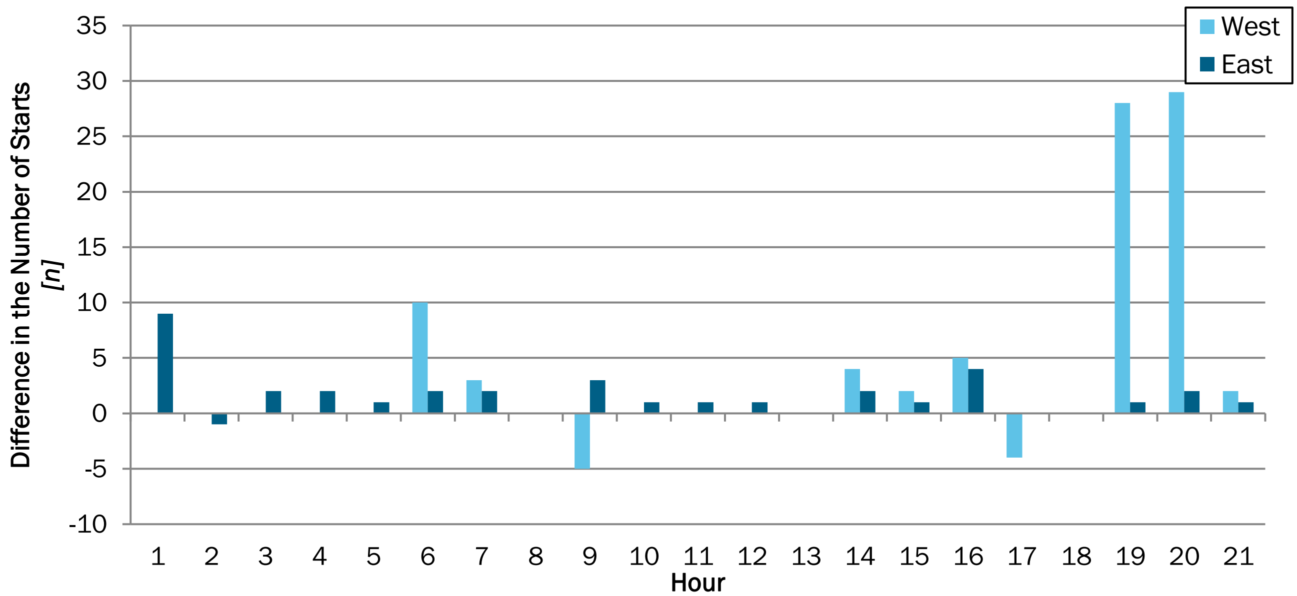


Figure 78: Change in Generator Starts, March (Market Study – Production Baseline)



Curtailments of Existing Renewables

Wind and hydroelectric resources are an important part of the dispatchable generation mix in the NYCA. While these renewable resources are rarely curtailed unless it is necessary to alleviate transmission congestion or over-generation, renewable resource output was curtailed more frequently in the RTM Market Study days than the Production Baseline days. The following section provides comparisons of the outputs of existing facilities in the 2016 Production Baseline days to their outputs in the market study days. This analysis may be used to assess the impact that a large volume of new intermittent renewables could have on the grid as a whole.

Wind Curtailments

Figure 79, Figure 80, and Figure 81 compare the difference in real-time output between Production Baseline and Market Study days for wind facilities that exist in the NYCA today. Curtailments of wind resources added solely for the market study were not analyzed, nor were curtailments as a percentage of total nameplate capacity.

On an average hourly basis, up to 73% of the output of existing wind facilities was cut in the Market Study days compared to the 2016 Production Baseline days. During the March and July Market Study days, wind output was dispatched down dramatically as the output from solar resources increased and net load decreased around mid-afternoon.

In the November Market Study day, curtailments were more consistent throughout the day (see Figure 81). This was likely related to the particularly high winds on this day. Wind generation in the Market Study surpassed 50% of the total NYCA generation that day, even with the curtailments.

Figure 79: Difference in Real-Time Average Hourly Wind Generation, March Day (Market Study-Production Baseline)

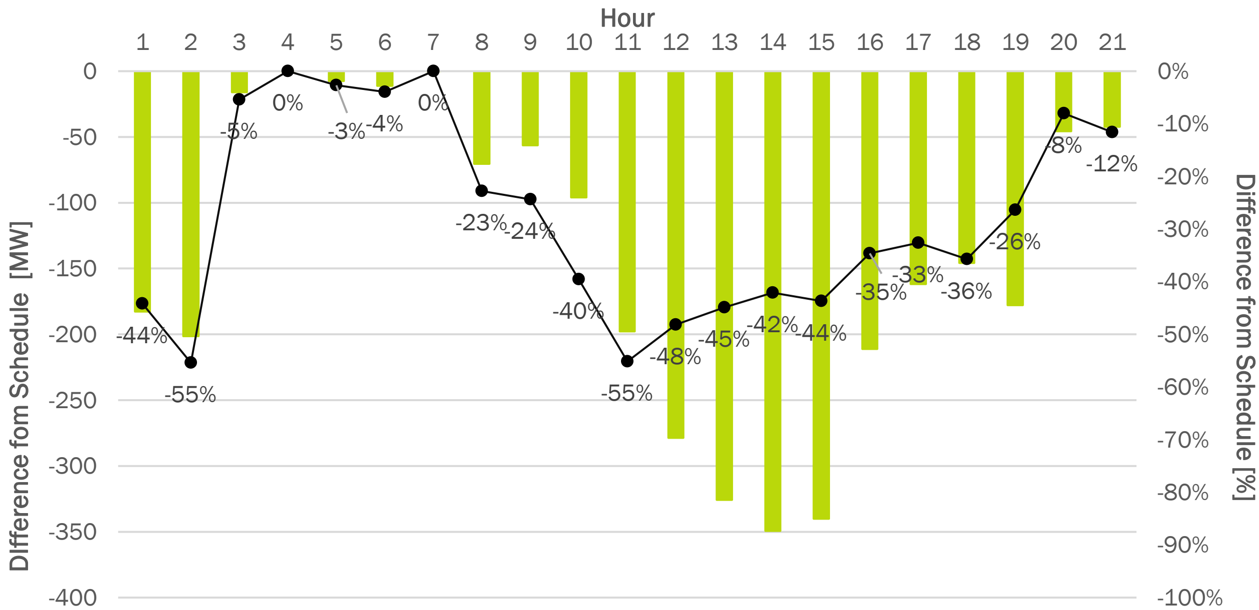


Figure 80: Difference in Real-Time Average Hourly Wind Generation, July Day (Market Study-Production Baseline)

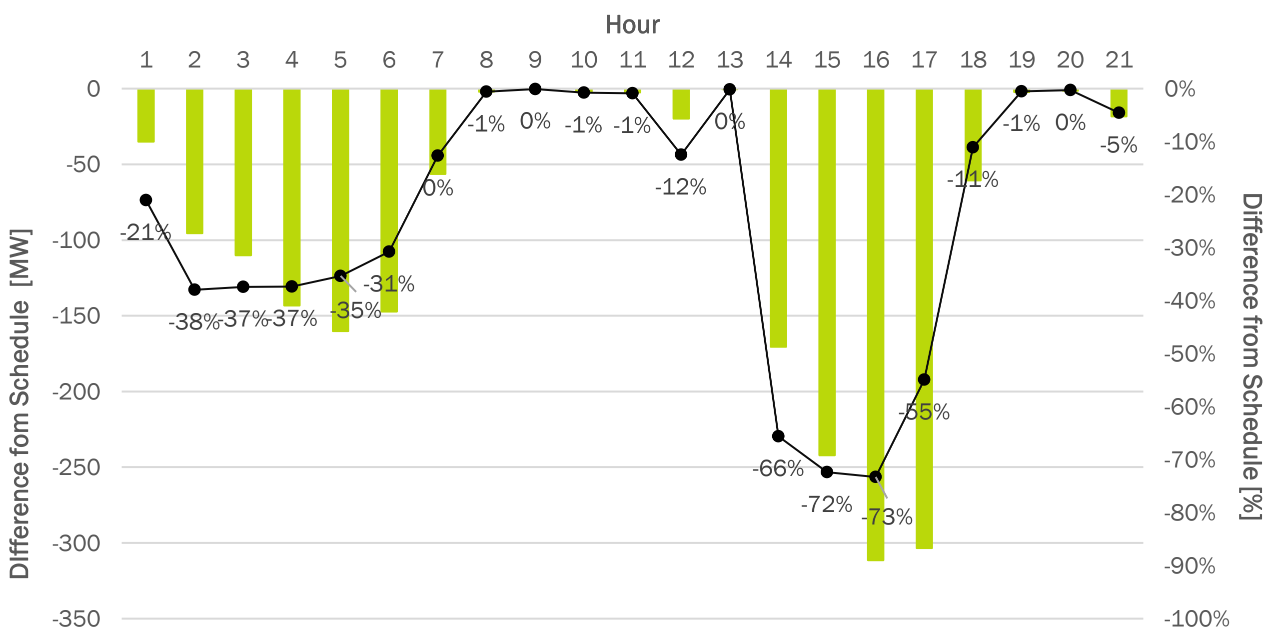
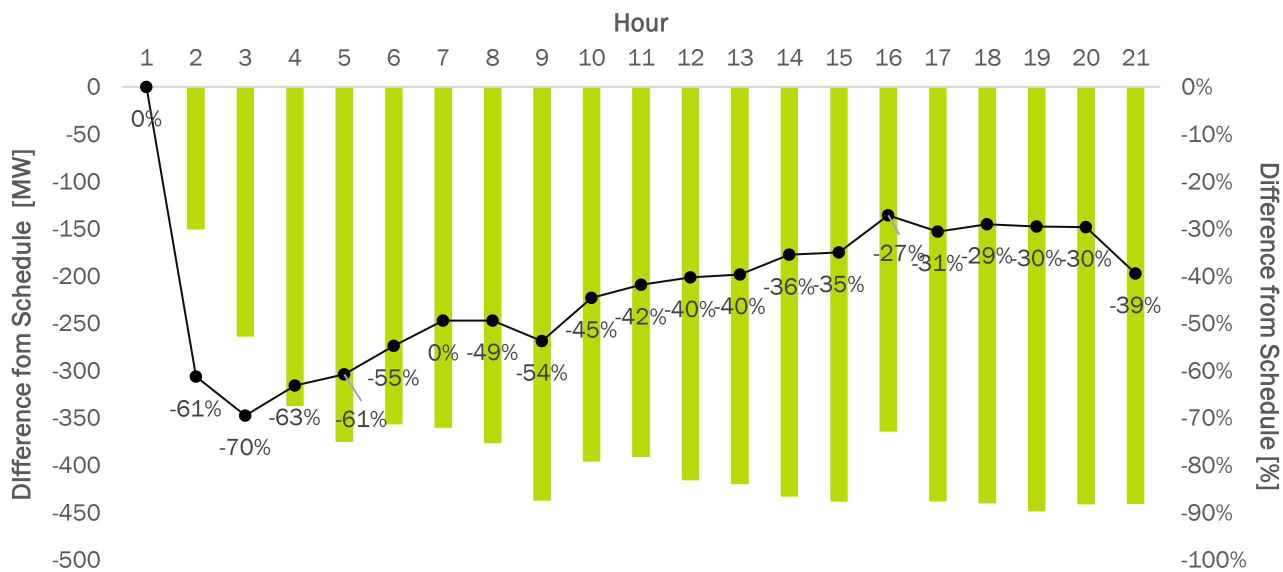


Figure 81: Difference in Real-Time Average Hourly Wind Generation, November Day (Market Study-Production Baseline)



Conventional Hydroelectric Curtailments

Figure 82, Figure 83, and Figure 84 compare the real-time difference in output between Production Baseline and Market Study days for hydroelectric facilities that exist today in the NYCA . Curtailments of hydroelectric resources added solely for the Market Study were not analyzed, nor were curtailments as a percentage of total nameplate capacity.

Across the March, July and November Market Study days, the share of conventional hydroelectric resources as a portion of total generation decreased on average from 19% to 10%. The difference in generation dispatched was as large as -500 MW, or 82% lower than the Production Baseline. The total daily output variability was most significant during the November day at -56%. During this day, the relative contribution of renewable resources was also higher as a proportion of total generation.

Like wind, increased hydroelectric curtailments are associated with the increase in solar output and decrease in net load that were characteristic of the Market Study days.

Figure 82: Difference in RT Average Hourly Hydroelectric Generation, March Day (Market Study-Production Baseline)

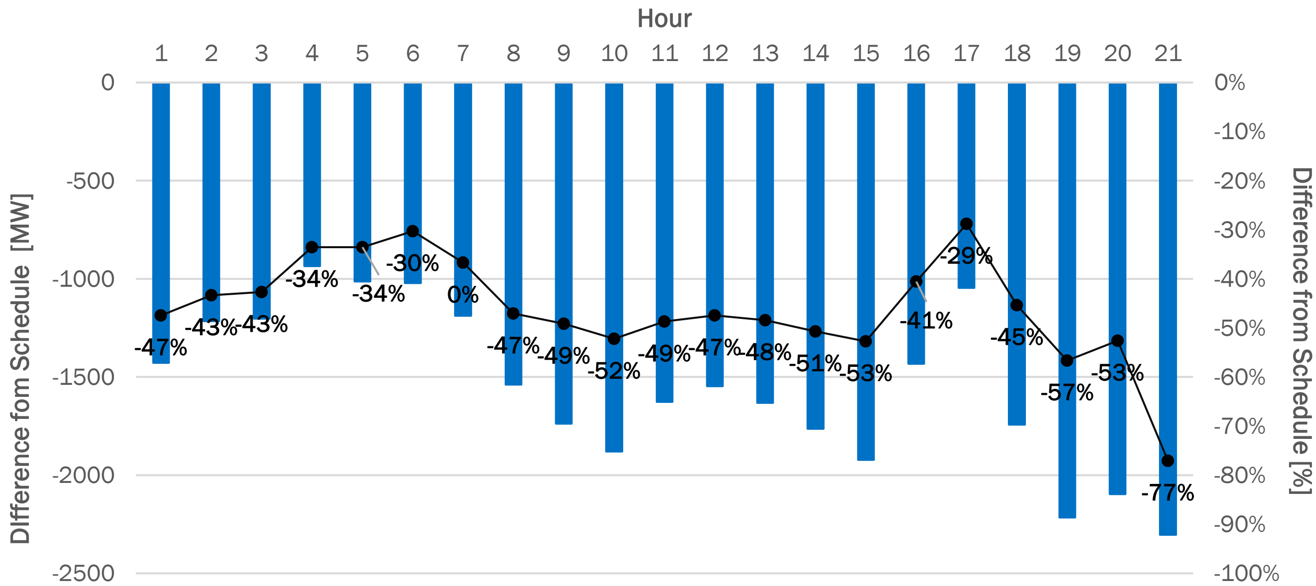


Figure 83: Difference in RT Average Hourly Hydroelectric Generation, July Day (Market Study-Production Baseline)

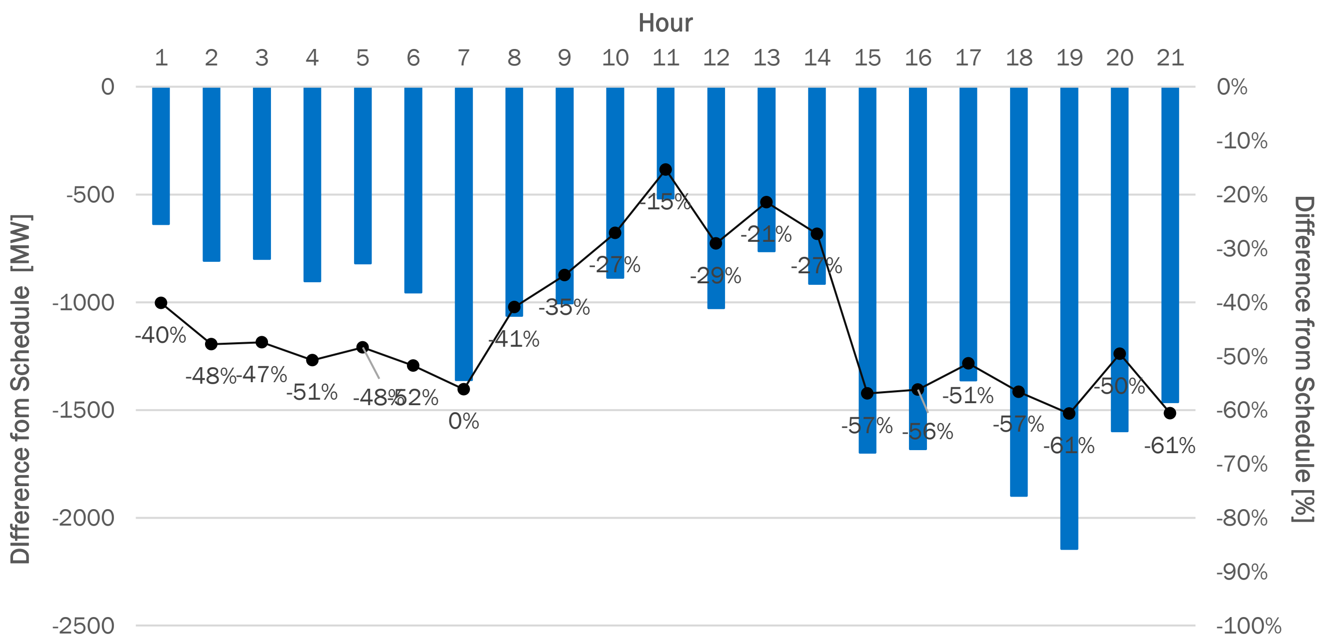
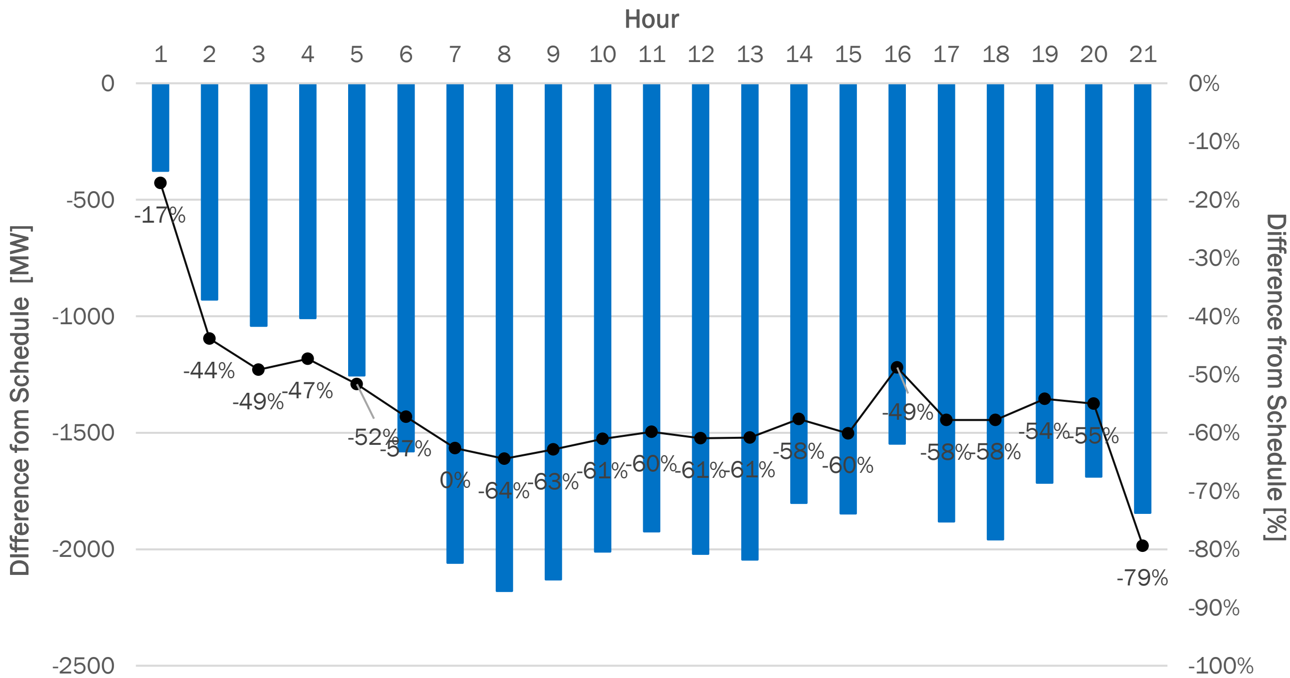


Figure 84: Difference in RT Average Hourly Hydroelectric Generation, November Day (Market Study-Production Baseline)



Incremental Renewable Schedules

Figure 85, Figure 86, and Figure 87 compare the real-time bid energy of front of the meter Incremental Renewables to their scheduled output on the November day. Because front of the meter Incremental Renewables were modeled as having offered at their anticipated output levels, the difference between offered and scheduled energy is equivalent to the available Incremental Renewable energy that was not fully utilized due to NY Power System constraints and/or low net load. The largest differences between bid and scheduled energy notably coincided with maximum solar output on the March and November Market Study days. Load was high enough that Incremental Renewables were almost fully deployed on the July Market Study day.

Figure 85: Real-Time Average Hourly Schedules of Incremental Renewables in the Market Study, March Day

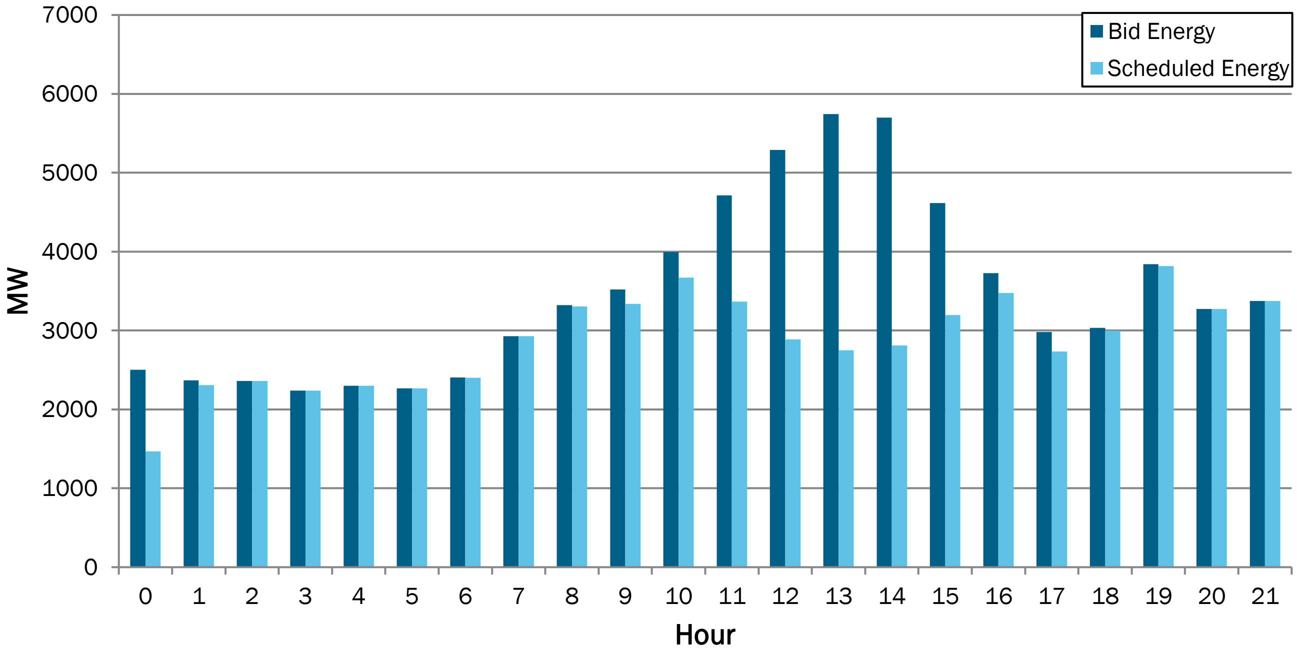


Figure 86: Real-Time Average Hourly Schedules of Incremental Renewables in the Market Study, July Day

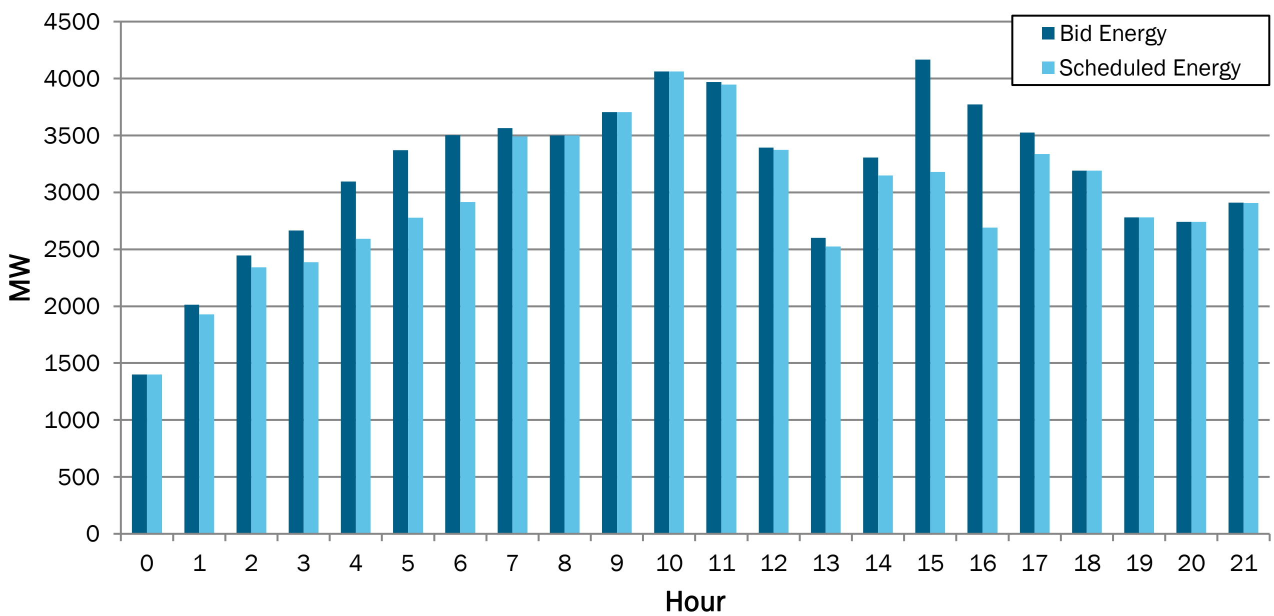


Figure 87: Real-Time Average Hourly Schedules of Incremental Renewables in the Market Study, November Day

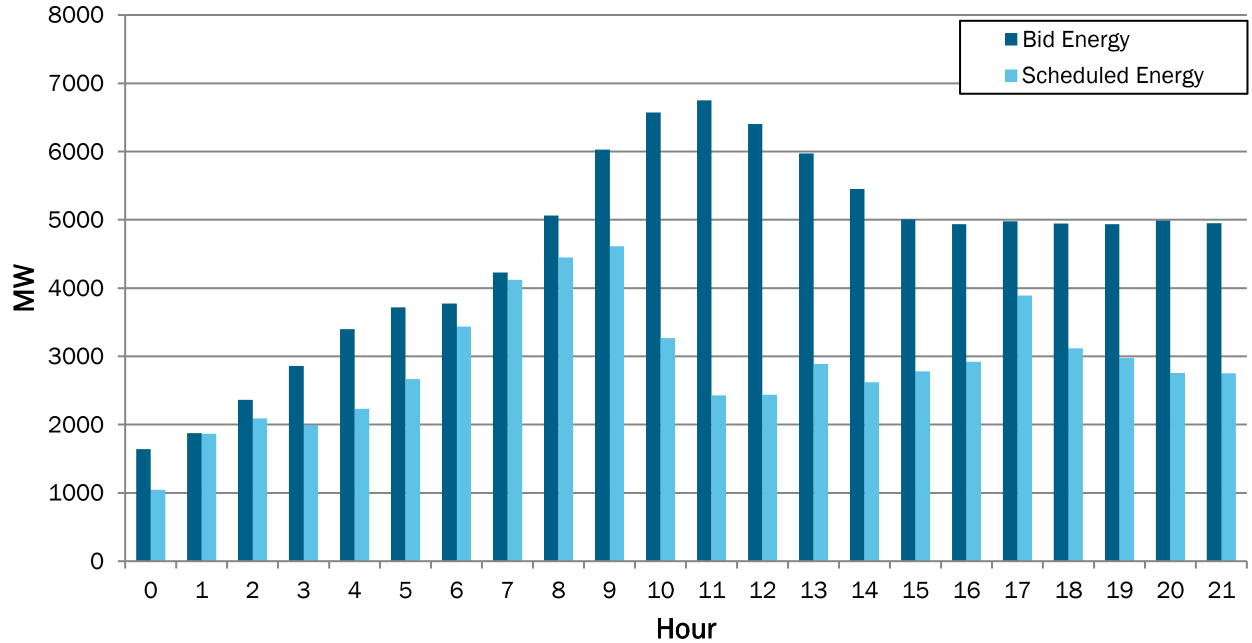


Figure 90 and Figure 91 show the difference between the total energy that could have been delivered by Incremental Renewables and what was scheduled for each RTM Market Study case.

Figure 88. Available Incremental Wind Energy Not Deployed in the RTM Market Study [MWh]

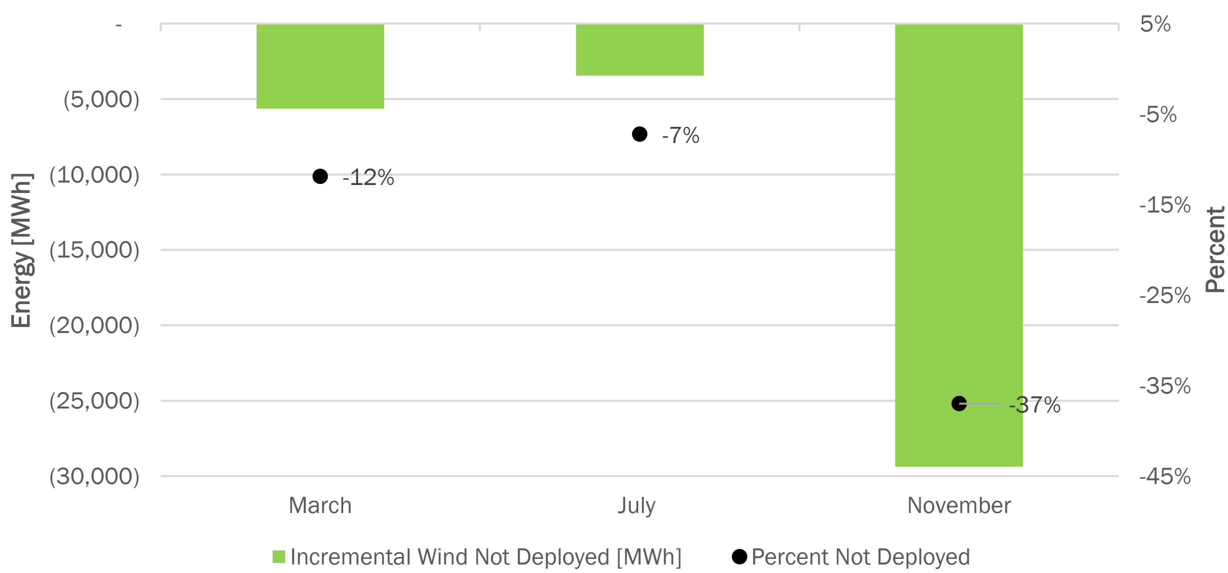
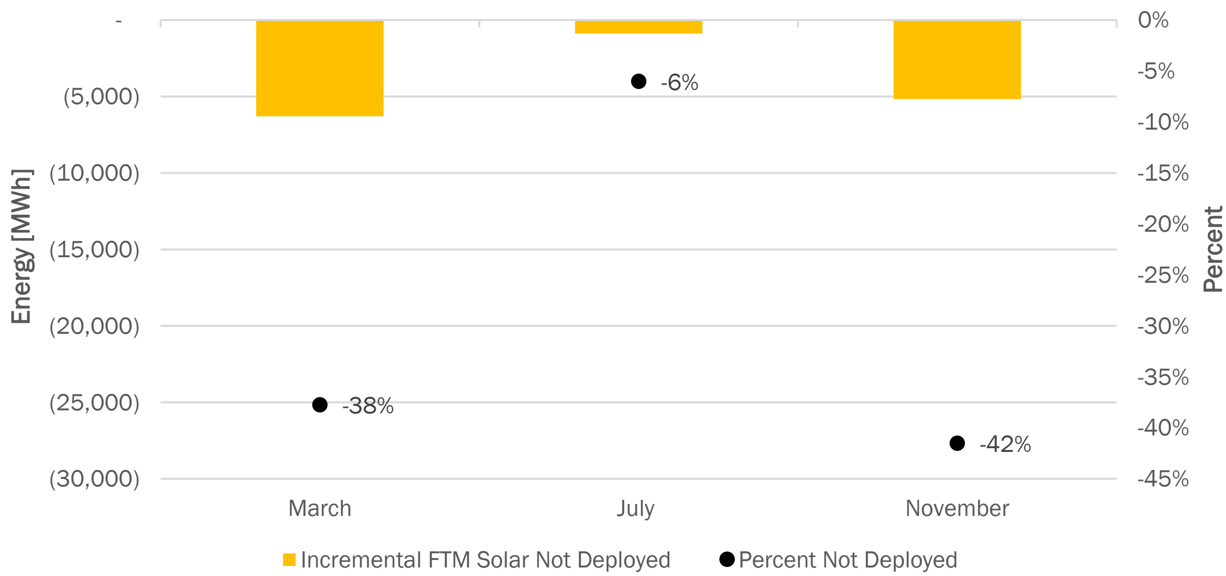


Figure 89. Available Incremental Solar Energy Not Deployed in the RTM Market Study [MWh]



Ancillary Services

Prices

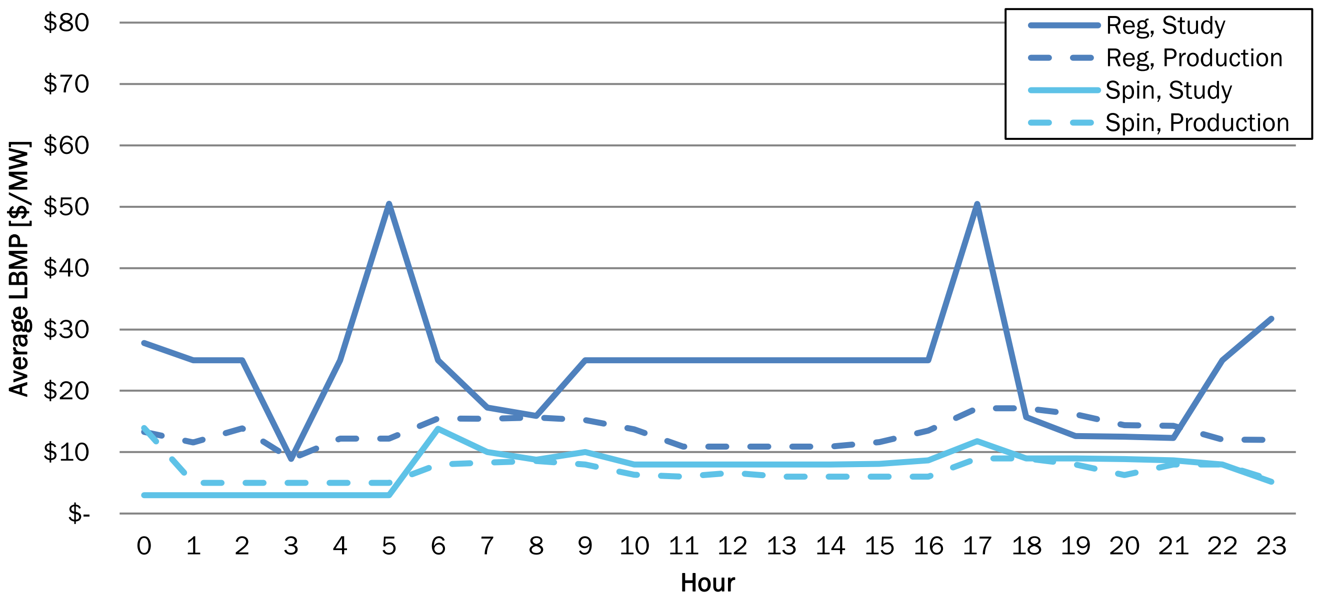
Regulation and East Spinning Reserve prices for all four Production Baseline and Market Study days are discussed in this section. Prices are reported in $/MWh. Five-minute Regulation prices were averaged on an hourly basis and were the same across all zones (A-K), while East Spinning Reserve prices were averaged across zones F-K. In the Market Study, requirements for Regulation and Reserves were equal to the Production Baseline requirements. This was not entirely representative of likely future conditions, because it is expected that the NYISO will increase Regulation procurement as more intermittent renewables enter the generation mix. Price differences, are reflective of the relative ability of flexible resources to provide Ancillary Services products.

Low load and increased renewable energy production in the January, March, and November Market Study cases caused fewer flexible units to be committed. Regulation prices were then set higher because many of the typical Regulation providers stayed offline. There was little change in East Spinning Reserve or other ancillary services prices in the Market Study cases.

January Day

Day-Ahead prices for East Spinning Reserves in the January Market Study were very similar to the Production Baseline case, while Day-Ahead Regulation prices were higher for most hours of the Market Study day. Lower net demand caused fewer flexible resources like steam and combined cycle units to be committed. Because fewer resources with the ability to regulate output up and down every six seconds were online, the cost of Regulation went up.

Figure 90: Average DAM Regulation and East Spinning Reserve Prices, January Day



March Day

In the March Market Study day, the Regulation price cleared above the Production Baseline price in both the Day-Ahead and real-time simulations. Similar to the January day, modeled renewable resources forced flexible generation to remain offline during peak hours, driving Regulation prices up. East Spinning Reserve prices in the Market Study case remained similar to the prices observed in the Production Baseline case.

Figure 91: Average DAM Regulation and East Spinning Reserve Prices, March Day

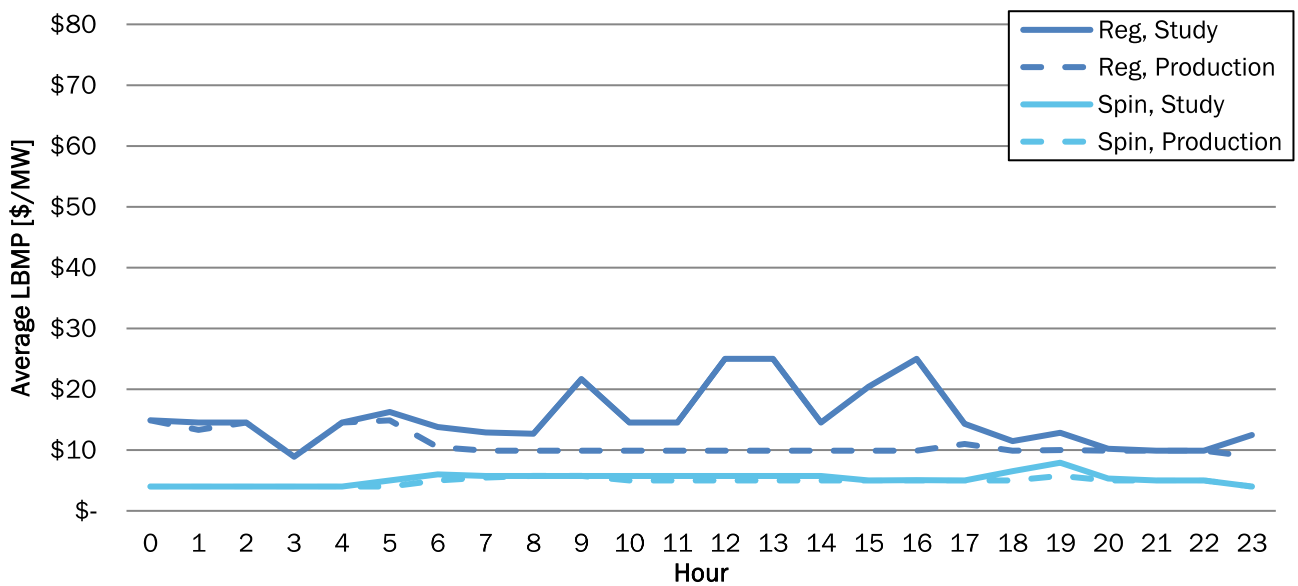
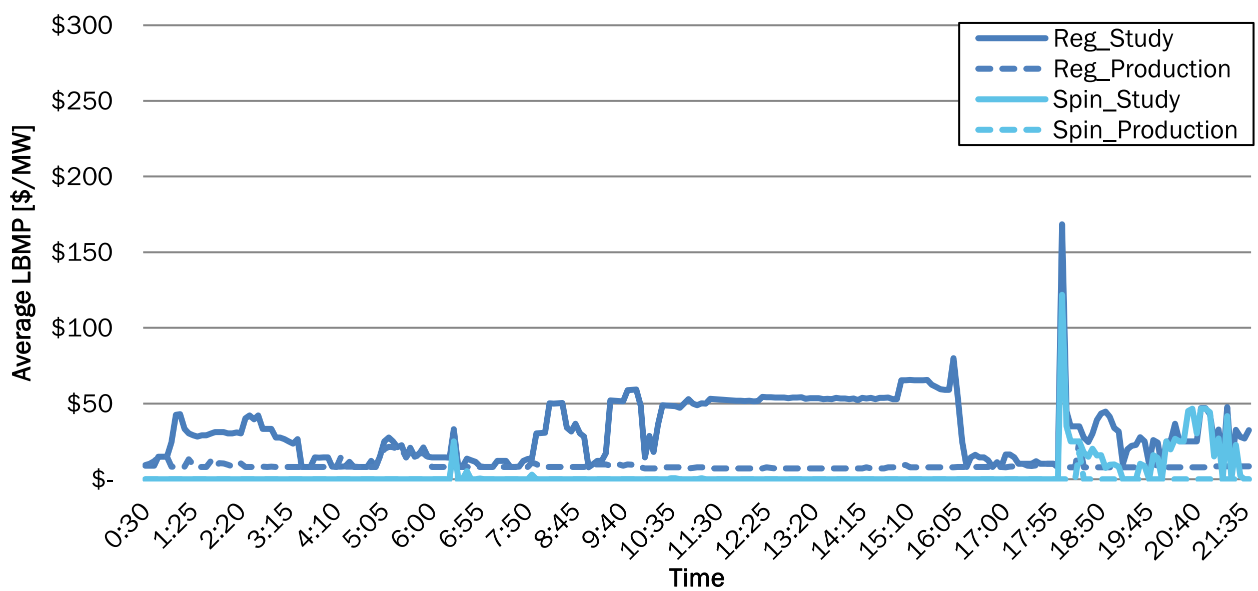


Figure 92: Average RTD Ancillary Services Prices, March Day



July Day

In the Market Study, Incremental Renewables were scheduled to help meet summer demand during peak hours in the DAM. Unlike the January and March Market Study cases, overall load was high enough that flexible units were scheduled to remain online. As the forecast solar output increased, they were dispatched down near their lower operating levels where they competed to provide ancillary services. As a result, Regulation cleared at lower prices in the Market Study than in Production Baseline. In real-time, Regulation prices were similar to Day-Ahead prices. They increased in the evening as the simulated solar output decreased, and the net evening load ramp increased.

Spikes in real-time Synchronous Reserve prices in both the Production Baseline and the Market Study are likely related to the thunderstorm event that occurred on the July 2016 day.

Figure 93: Average DAM Regulation and East Spinning Reserve Prices, July Day

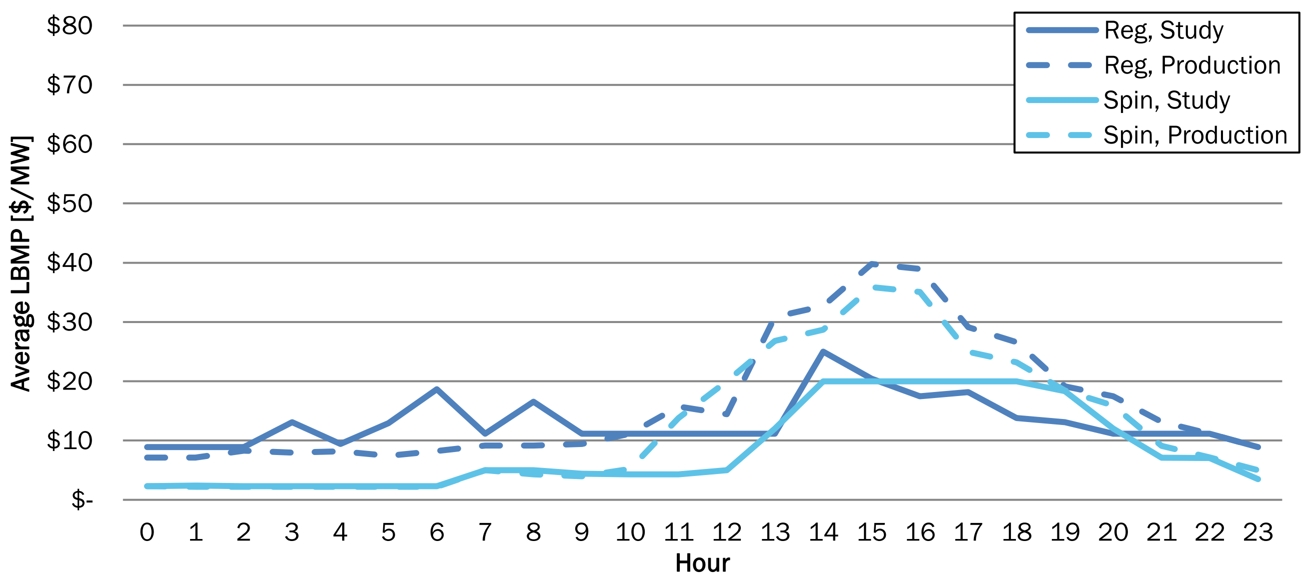
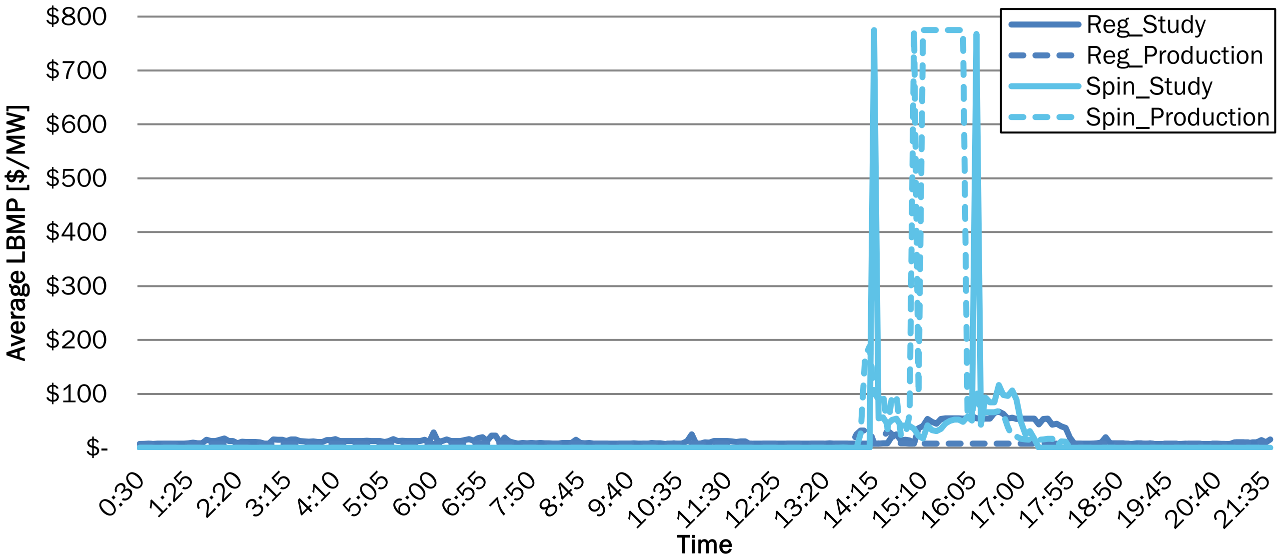


Figure 94: Average RTD Regulation and East Spinning Reserve Prices, July Day



November Day

In the November Market Study day, fewer resources with the ability to follow a Regulation signal were committed, which caused the price of Regulation to clear much higher in some hours than during the Production Baseline day. At hour beginning eight (8), the DAM Market Study Regulation price climbed to $120.61/MWh. Spinning Reserve prices remained relatively flat.

The NYISO uses demand curves that reflect the cost of the shortage(s) to price products when there are no marginal resources available to solve the need. For example, a violation of the Regulation requirement between 0 to 25 MWs incurs a $25 penalty, and a violation between 25 to 80 MW incurs a $525 penalty. In Real-Time, the price for Regulation increased to $525.00/MWh for multiple intervals in the morning, when a Regulation shortfall of greater than 80 MW caused the price to be set by the Regulation demand curve. Despite higher demand for regulating resources, the clearing prices for other ancillary service products remained near Production Baseline levels.

Figure 95: Average DAM Regulation and East Spinning Reserve Prices, November Day

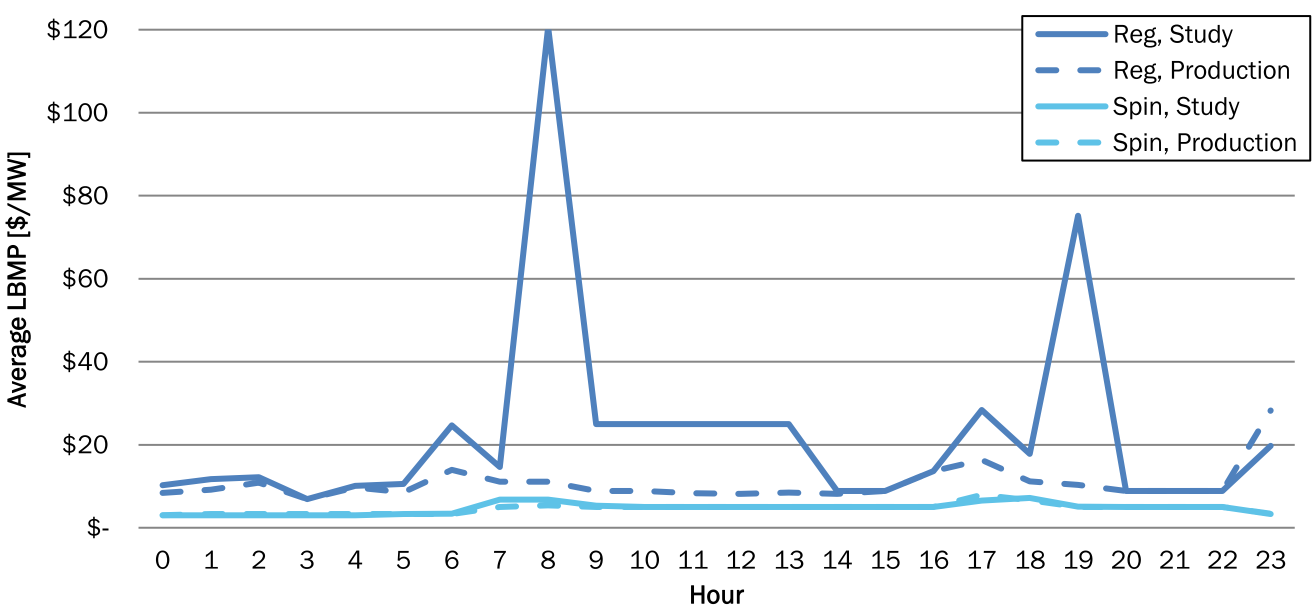
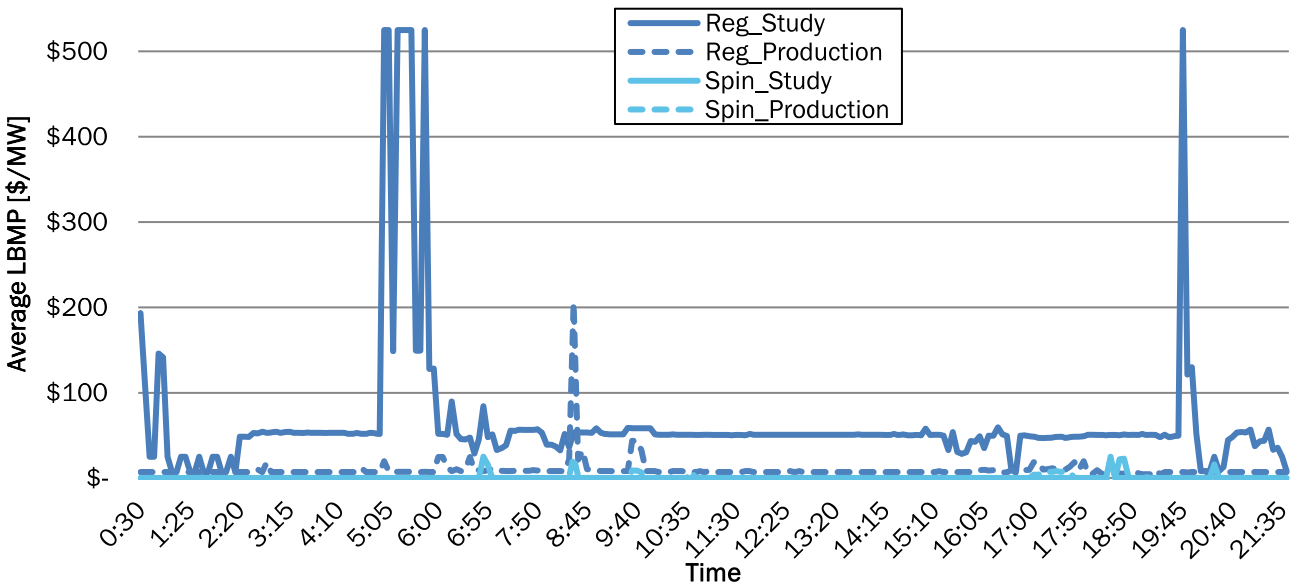


Figure 96: Average RTD Regulation and East Spinning Reserve, November Day



Shortages

Shortage data is presented in Figure 97, where “Study Shortage Difference” was calculated according to (Equation **1)**.

$$Study\ Shortage\ Difference\ = Avg\ Shortage, Study - Avg\ Shortage, Baseline \qquad \text{(Equation 1)}$$

Long Island (LI) Reserve clearing prices are equal to the respective Southeastern New York (SENY) Reserve clearing prices.

Figure 97: Ancillary Services Shortage Data

	Production Baseline			Market Study			Difference*	
	Avg Shortage [MW]	Shortage Interval Count	Avg Clearing Price [$/MW]	Avg Shortage [MW]	Shortage Interval Count	Avg Clearing Price [$/MW]	Shortage [MW]	Clearing Price [$/MW]
NYCA 30	0.5	4.0	$ 0.19	0.0	0.0	$ 0.00	-0.5	$ (0.19)
NYCA 10	0.0	0.0	$ 0.19	0.0	0.0	$ 0.00	0.0	$ (0.19)
NYCA SPIN	0.0	0.0	$ 0.62	0.0	0.0	$ 0.14	0.0	$ (0.48)
EAST 30	0.0	0.0	$ 0.19	0.0	0.0	$ 0.00	0.0	$ (0.19)
EAST 10	1.2	11.0	$ 13.72	0.5	4.0	$ 7.74	-0.8	$ (5.98)
EAST SPIN	0.0	1.0	$ 14.34	0.7	6.0	$ 8.71	0.7	$ (5.63)
SENY 30	0.0	0.0	$ 0.19	0.0	0.0	$ 0.00	0.0	$ (0.19)
SENY 10	0.0	0.0	$ 13.72	0.0	0.0	$ 7.74	0.0	$ (5.98)
SENY SPIN	0.0	0.0	$ 14.34	0.0	0.0	$ 8.71	0.0	$ (5.63)
LI 30*	0.1	3.0	$ 0.19	0.2	6.0	$ 0.00	0.0	$ (0.19)
LI 10*	0.0	0.0	$ 13.72	0.3	8.0	$ 7.74	0.3	$ (5.98)
LI SPIN*	0	0.0	$ 14.34	0	0.0	$ 8.71	0.0	$ (5.63)
REGULATION	0	0.0	$ 14.34	13.19	412.0	$ 37.77	12.9	$ 29.02

*Difference is calculated according to **(Equation 1)**

Shortages of longer lead-time products typically decreased between the Production Baseline and Market Study cases, whereas products procured closer to the real-time interval, such as Regulation and East 10-minute Spinning Reserves, saw more shortages in Market Study cases relative to Production Baseline cases. The average Reserve clearing price for East Spin was lower in the Market Study case than in the Production Baseline case. Regulation shortages were frequent and the average clearing price was higher.

Regulation Service

The Regulation service requirements procured by the NYISO are based on the load ramp required throughout the day. Descriptive statistics of the load ramp delta between 5-minute intervals are presented in Figure 98 as average values from the real-time results of each Market Study and Production Baseline case. On the November Market Study Day, there was a 145% increase in the range of load ramp between real-time intervals. An increase of 44% was observed on the July Market Study Day. There was little difference between the Production Baseline and Market Study cases on the March day.

Figure 98: Real Time Load Ramp Statistics

	Production Baseline				Market Study				Difference in Range	
Study Day	Avg Load Ramp [MW]	Max Load Ramp [MW]	Min. Load Ramp [MW]	Range [MW]	Avg Load Ramp [MW]	Max Load Ramp [MW]	Min. Load Ramp [MW]	Range [MW]	Range [MW]	Range [%]
March	10	610	-130	740	5	511	-215	726	-14	-2%
July	17	379	-267	646	11	502	-430	932	286	44%
November	12	257	-121	378	0	615	-310	925	547	145%

Ramp Capability of Flexible Generators

In the Market Study, flexible generators like combined cycle power plants were dispatched down near their lower operating limits or turned off as solar output rose each day. When solar production tapered off in the evening, flexible units were dispatched back up. A corresponding trend in the total down-ramp capacity available to the NY Power System was observed. Generator down-ramp capacity was higher when flexible units were online and operating above their minimum generation levels. Similarly, up-ramp capacity was higher when flexible units were online and operating below their maximum generation levels. This is most easily observed in the July Market Study day, during which peak demand was high enough that more flexible generators were forced to stay online because renewables alone could not fully serve the load. A reduction in flexible resource ramp availability was still observed, but was less severe than in the March or November cases.

Generally, intermittent renewables can be curtailed or turned off very quickly. It is important to note that this analysis does not consider that ability when calculating available down-ramp. The inclusion of intermittent renewables in the down-ramp calculations would change the results significantly. For example, during hour beginning ten (10) in the July day, the difference in available ramp in real-time between the Market Study and Production Baseline case was approximately -760 MW, or -48%. The scheduled output from renewables during the same hour was approximately 4,000 MW. It is reasonable to assume that some portion of those renewables could have been dispatched down if necessary, providing the "missing" ramp.

During some periods in the Market Study cases, available up-ramp was short in comparison to the Production Baseline cases. This was particularly true on the March day, and during periods when flexible generators were either offline or operating at their maximum output levels.

Figure 99. Flexible Generator Ramp Comparison, (Market Study - Production Baseline), March Day

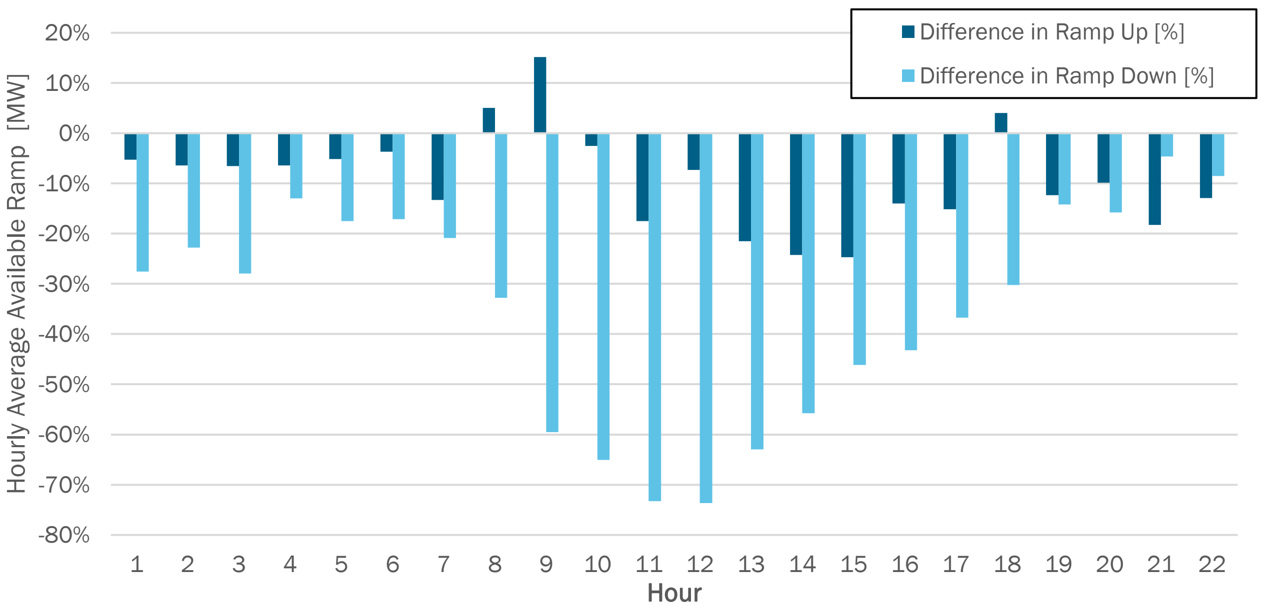


Figure 100. Flexible Generator Ramp Comparison, (Market Study - Production Baseline), July Day

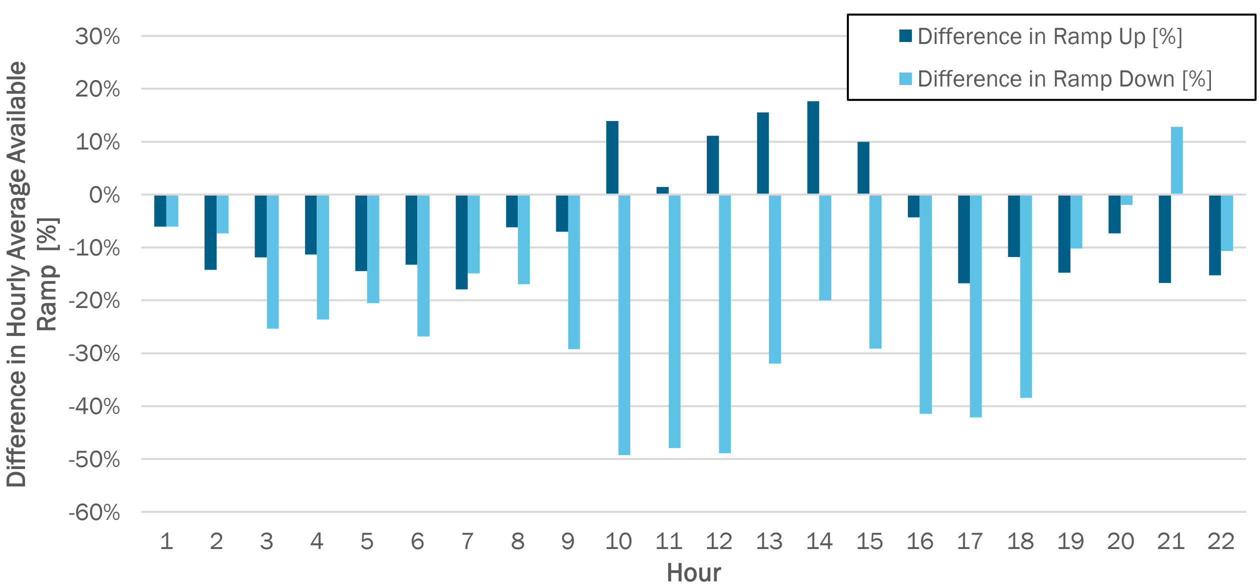
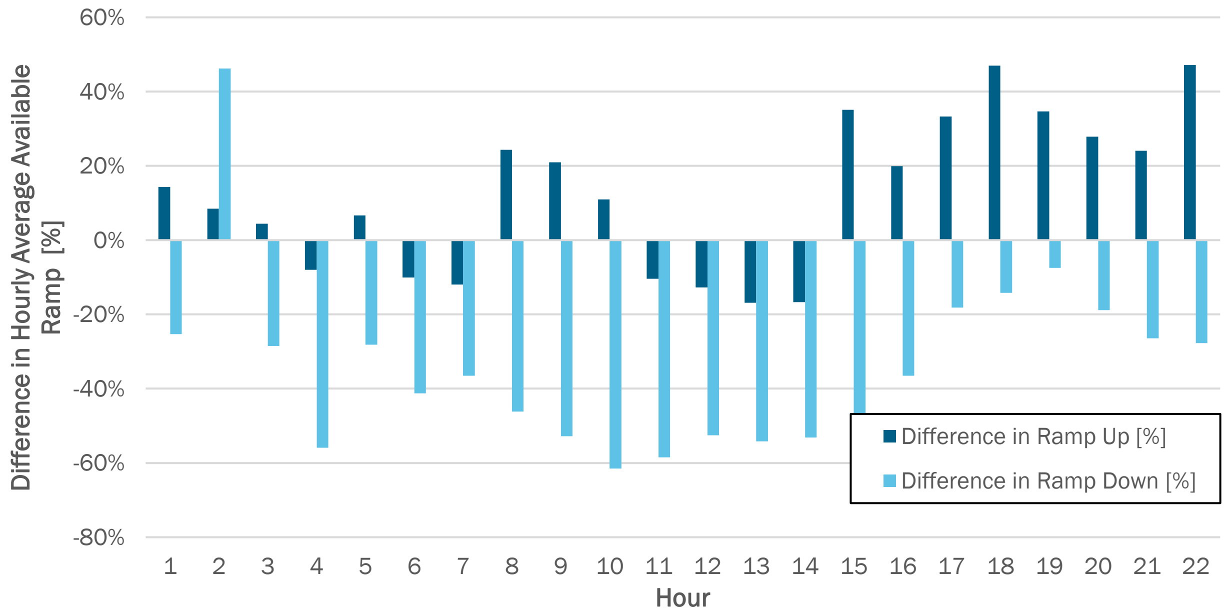


Figure 101. Flexible Generator Ramp Comparison, (Market Study - Production Baseline), November Day



Capacity Market Study Results

The results discussed in this section were the product of the NYISO's Capacity Market Study. They were created using models of the ICAP market and the rules thereof, and should not be interpreted as certain or forecasted outcomes.

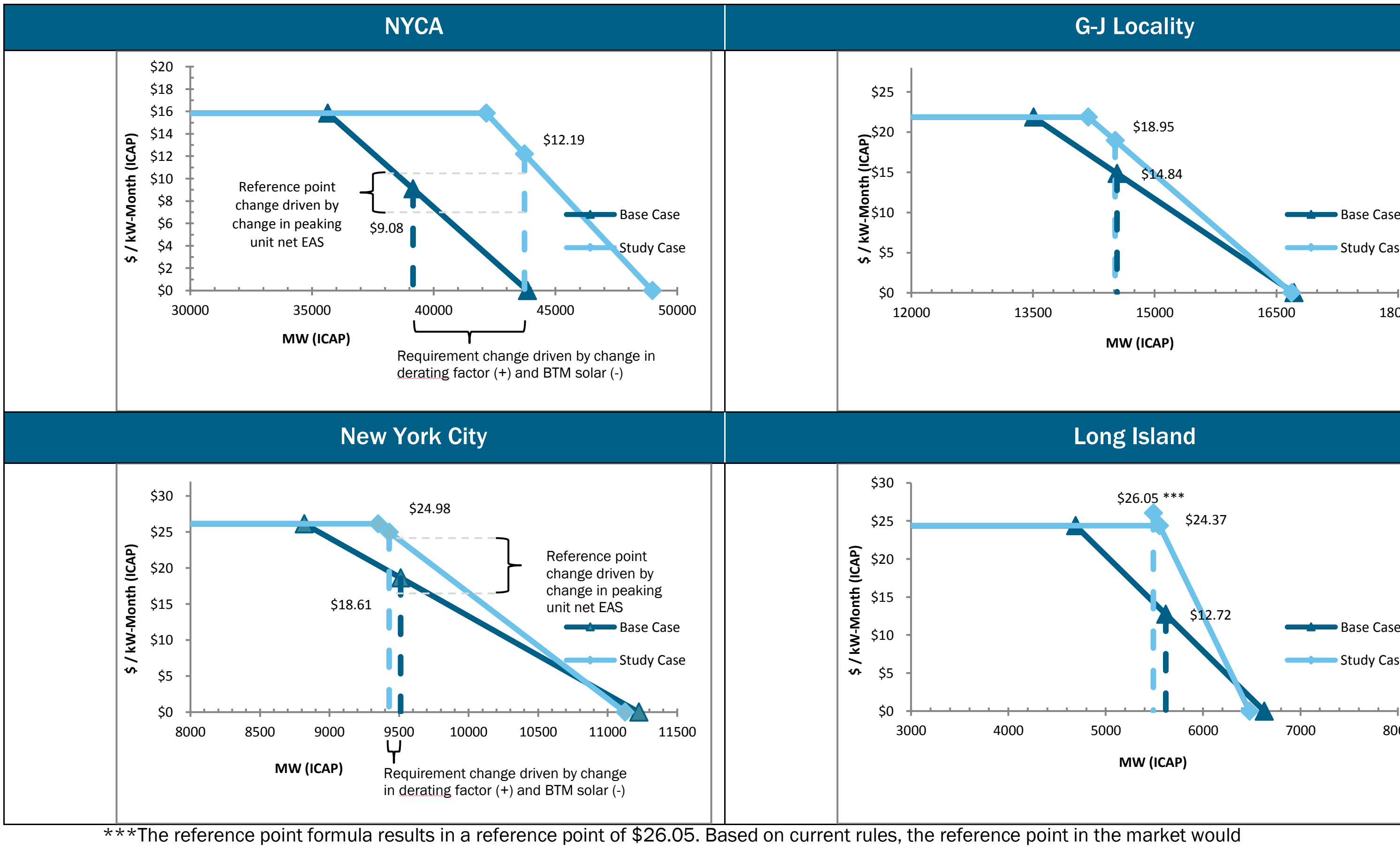
In general, the study indicates NYISO ICAP Market would respond to additional renewable energy resources predictably. After reviewing Market Study assumptions and results with stakeholders, the NYISO received broad feedback that the Capacity Market Study outcomes fell within general expectations.

After the entry of the renewable generators ("Study Case"), the NYISO would require a larger number of nameplate megawatts of capacity to meet resource adequacy criteria (i.e., the Installed Reserve Margin and Locational Minimum Installed Capacity Requirements would increase). This result is due because the Incremental Renewables have lower availability during peak periods than the current set of capacity suppliers. As a result of their lower average availability, renewable resources could not displace a today's fleet average capacity on a one-for-one basis. For the levels of renewable entry present in this study, the study's first-order estimates suggest that four megawatts of Incremental Renewables could displace approximately one megawatt of today's fleet average capacity. The study results further suggested that if renewable resources did not displace other, pre-existing, capacity, then capacity prices would likely decrease substantially relative to current prices. That is, the capacity revenue available would decrease if total capacity cleared in the market included all of today's existing capacity and Incremental Renewables.

The ICAP study results suggested that the availability of renewable resources during periods of NY Power System stress contributes to the capacity market impacts of those generators, both by determining the resources available to operate the NY Power System (*i.e.*, supply) and the mix and quantity of resources needed to meet requirements (*i.e.*, demand).

Market Study Case ICAP Requirements remained flat, except for an increase in the NYCA. The UCAP Requirement decreased in all three Localities. The observed changes in capacity requirements were related to two variables: Firstly, the Incremental Renewables in the Market Study had lower availability, on average, than the Base Case resources. As a result, Market Study Case required reserve margins were substantially greater than Base Case required reserve margins, which directly increased the ICAP requirement. Secondly, the added resources included substantial quantities of behind the meter solar. Current market rules treat these resources as an offset to load which reduce peak load and the capacity requirement by extension.

Figure 102: ICAP Demand Curves for the Capacity Base Case and the Capacity Market Study Case.



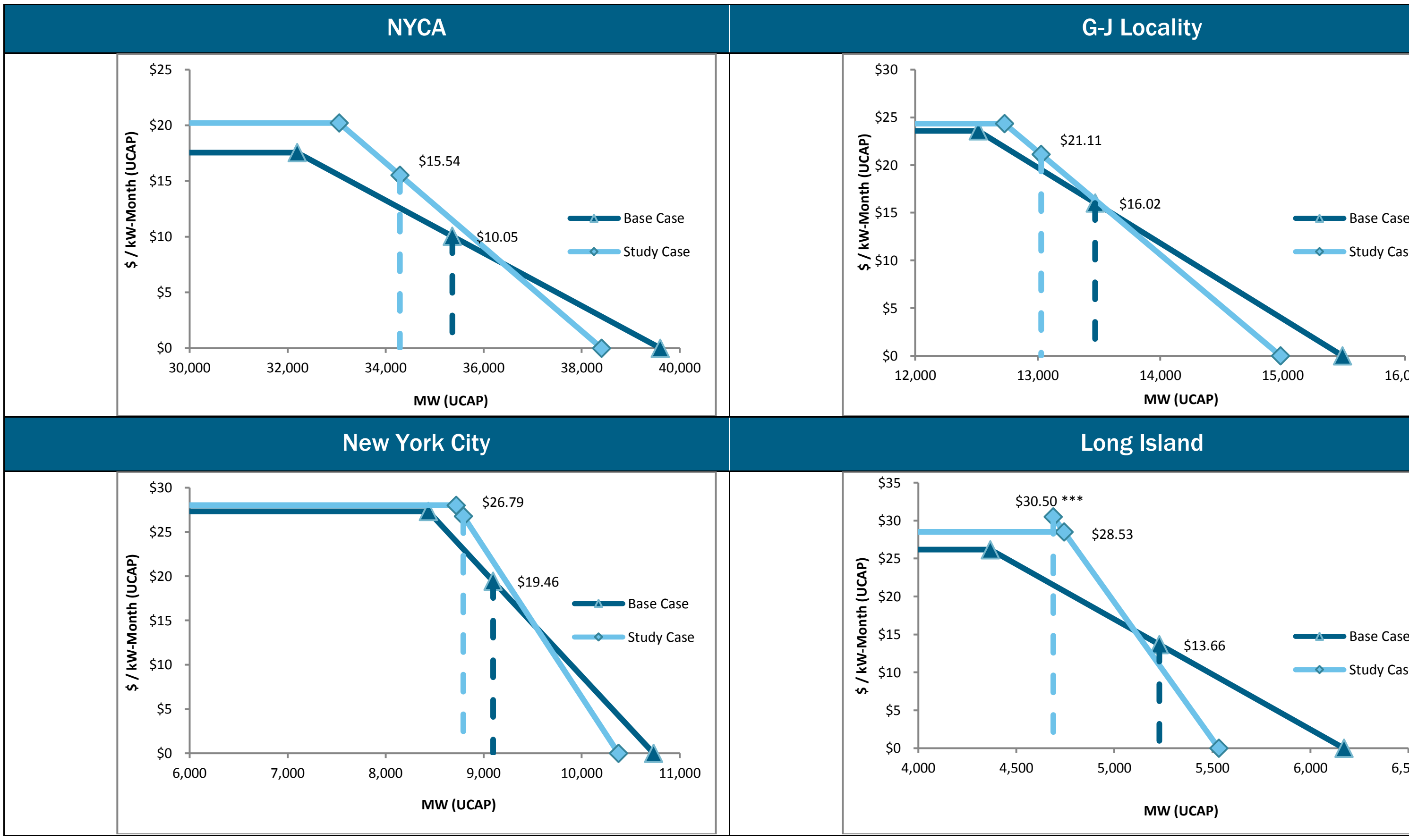
***The reference point formula results in a reference point of $26.05. Based on current rules, the reference point in the market would be a max clearing price of $24.37.

Demand Curves from the Market Study case varied from the Base Case in several ways. Reference Points, or the capacity prices at the capacity requirement, were higher in the Market Study. The increase was driven by the assumed reduction in net energy revenues earned by the hypothetical peaking plant. On the whole, Market Study Case Demand Curves were also steeper than Base Case Demand Curves, despite substantially larger required reserve margins. Figure 102 shows the Base Case and Market Study Case ICAP Demand Curves for all capacity locations in New York, and Figure 103 shows the equivalent UCAP Demand Curves.

The NYCA and New York City ICAP Demand Curves also identify primary drivers of the change in the Demand Curve. The primary drivers are the same in the G-J Locality and Long Island.

UCAP requirements fell in all locations, primarily due to the increase in behind the meter solar that decreased peak load.

Figure 103: UCAP demand curves for the Capacity Base Case and the Capacity Market Study Case



***The reference point formula results in a reference point of $30.50. Based on current rules, the reference point in the market would be a max clearing price of $28.53

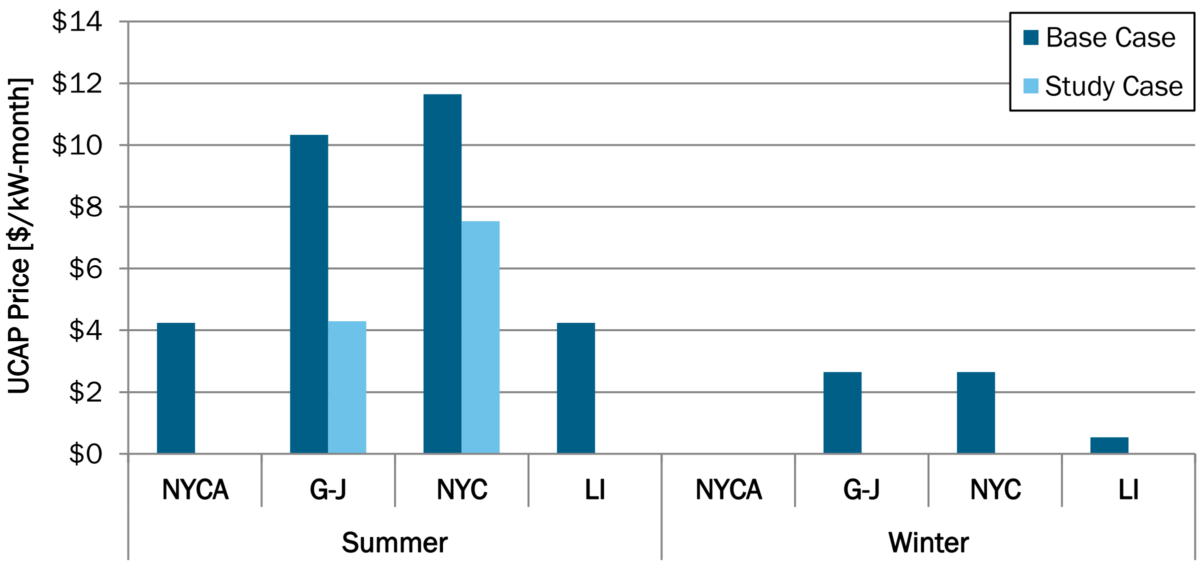
After translating nameplate capacity into UCAP, the Market Study UCAP was between two (2) and eight (8) percent higher than Base Case UCAP, which also varied by location.

Capacity Market Study Observations

As a result of the modified Demand Curves and capacity supplies, summer supply and demand balances shifted. Capacity supply in the Market Study exceeded Base Case supply in all locations. Capacity demand (*i.e.*, the product of peak load and the capacity requirement) was either similar to or smaller than it was in the Base Case, depending on location. Shifts in supply and demand balances were most pronounced in the NYCA and Long Island. As expected, Capacity prices decreased substantially relative to Base Case capacity prices. With the exception of NYC and the G-J Locality during the Summer Capability Period, low prices indicate that the Market Study was oversupplied with capacity relative to what was necessary.

Increases in UCAP supply without commensurate increases in UCAP demand put downward pressure on prices in all locations.

Figure 104: UCAP prices in the Base Case and the Market Study Case



The additional sensitivity analyses performed confirmed the initial Market Study results, concluding that additional renewable resources are likely to increase the value of both the IRM and LCRs, degrade the average performance level of capacity resources, and have little effect on the total UCAP, or capacity required to maintain a reliable NY Power System. The decline in capacity prices is also attributable to the fact that the Incremental Renewables increased total capacity supply.

Figure 105 provides the results to a sensitivity study that identified the quantity of capacity that would need to exist in the market (*e.g.*, for the purposes of setting capacity requirements) but not clear in any auction or as a bilateral ('uncleared UCAP') in order for capacity prices to return to Base Case levels. Uncleared capacity could occur for various reasons, like increased export transactions, reduced import transactions, and internal capacity suppliers offering capacity at a price above the market clearing price. Any Generator Deactivations that cause capacity to exit the market could potentially alter the capacity requirement and/or system translation factor.

A priori, one would expect prices return to Base Case levels when uncleared UCAP approximately equals the UCAP of the additional renewable resources in the Market Study Case. The results of this sensitivity confirm this expectation: despite changes in capacity requirements and the system translation factor, the Market Study Case added approximately 3,000 MW of UCAP. Approximately 3,500 MW of uncleared UCAP would return prices to Capacity Base Case levels. Reductions in peak load from the Capacity Base Case to the Capacity Market Study Case help explain the 500 MW difference between added and uncleared capacity quantities. These results should be interpreted with care: reductions in available capacity (e.g. ,deactivation of generation that previously served as a capacity supplier) would not meet this Market Study's definition of uncleared UCAP. Were available capacity to decrease (e.g. ,due to generator deactivations), the system average derating factor, WSR, Net Energy and Ancillary Services (EAS), other Demand Curve parameters, and the capacity requirements could all potentially change. Thus, it is not appropriate to assume that this quantity of capacity would deactivate due to the Incremental Renewables in the Capacity Market Study Case.

Figure 105: UCAP sales information to return to Base Case Clearing Prices

UCAP SALES	NEW YORK CONTROL AREA							
			G-J Locality					
					New York City		Long Island	
[UCAP MW]	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
Spot Auction Price ($/kW-Month)	$4.24	$0.00	$10.33	$2.65	$11.64	$2.65	$4.24	$0.54
Load Forecast 2017	31,503.5	31,503.5	15,503.9	15,503.9	11,305.3	11,305.3	4,802.1	4,802.1
LCR/IRM Percentage	138.80%	138.80%	93.60%	93.60%	83.40%	83.40%	114.30%	114.30%
Demand Curve ICAP Ref Point	$12.19	$12.19	$18.95	$18.95	$24.98	$24.98	$26.05	$26.05
ICAP/UCAP Derating Factor	21.64%	20.95%	10.22%	9.53%	6.75%	7.40%	14.58%	16.51%
UCAP Ref Point	$15.56	$15.42	$21.11	$20.95	$26.79	$26.98	$30.50	$31.20
UCAP Requirement	34,264.2	34,565.0	13,029.2	13,128.8	8,792.2	8,731.2	4,688.3	4,582.7
Demand Curve Zero Crossing	112.00%	112.00%	115.00%	115.00%	118.00%	118.00%	118.00%	118.00%
UCAP at $0	38,375.9	38,712.8	14,983.6	15,098.1	10,374.8	10,302.8	5,532.2	5,407.6
Demand Curve Slope	(0.0038)	(0.0037)	(0.0108)	(0.0106)	(0.0169)	(0.0172)	(0.0361)	(0.0378)
Generation/SCR UCAP Available**	39,617.9	41,971.9	14,607.2	15,846.0	9,942.8	10,943.9	6,301.7	6,530.3
Imports	1,413.7	1,172.9	0.0	0.0	0.0	0.0	0.0	0.0
Exports	138.3	146.1	0.0	0.0	0.0	0.0	0.0	0.0
Unoffered MW	101.7	177.5	16.8	13.1	9.1	8.9	6.7	21.4
Unsold MW	4.6	164.1	4.0	14.3	4.0	18.4	0.6	1.8
Uncleared MW	3,532.0	3,880.0	559.0	970.0	242.5	694.0	872.3	1,113.8
Total MW Cleared***	37,255.0	38,777.1	14,027.4	14,848.6	9,687.2	10,222.6	5,422.1	5,393.3
MW Cleared Above Requirements	2,990.8	4,212.1	998.2	1,719.8	895.0	1,491.4	733.8	810.6
% Cleared Above Requirements	8.73%	12.19%	7.66%	13.10%	10.18%	17.08%	15.65%	17.69%

Appendix C: Description of Supplemental Appendices

To provide additional information that supports the NYISO's analysis, six Excel files are appended to this report. The data in these appendices represent Baseline Production and Market Study input and output data extracted from the NYISO's market solver (Ranger). Data from Ranger is not always directly comparable to data from the NYISO's OASIS postings, as described below. Brief descriptions of each Supplemental Appendix are provided below.

Supplemental Appendix 1: Assumptions Data and Profiles

Sources and profiles for all resources modeled in the Market Study. The development of these resource profiles is briefly described in Appendix A: Study Methodology, Renewable Capacity Added for Energy Market Study (47)

Supplemental Appendix 2: Energy Prices

Energy prices by zone are provided for both the Production Baseline and Market Study. Prices are provided for all three components of LBMP: Energy, Congestion and Marginal Losses.

Supplemental Appendix 3: Reserves Schedules and Prices

Clearing prices and schedules for all market-based ancillary services, including Spinning Reserves, 10 and 30-minute Operating Reserves, and Regulation. Clearing prices for Long Island Operating Reserves are those calculated by the NYISO market solver, and are not exactly equivalent to those that would be used for settlement purposes. As described in Section 6.5.2 of the NYISO's *Ancillary Services Manual*, suppliers of Operating Reserves located on Long Island receive settlement payments as if they were providing Operating Reserves located in Southeastern New York. In addition, the Regulation clearing price data in this file is the composite of the Regulation Capacity clearing price and the Regulation Movement price.

Supplemental Appendix 4: Changes in Scheduled MWh by Generation Type and Region

For existing resources, this file contains changes in MW schedules for energy and ancillary services between the Production Baseline and Market Study cases. To protect confidentiality, all data is presented in composite groups of multiple resources. Schedules for "Hydroelectric" resources include pumped storage. Schedules for "Peakers" are a composite of all combustion turbines, internal combustion engines and jet engines. Composite changes in schedules are also provided for zones west of Central East (Zone A – E) and zones east of Central East (Zones F – K).

Supplemental Appendix 5: Load Profiles by Load Zone

Provides Day-Ahead and Real-Time load profiles for the Production Baseline and the Market Study. The difference in loads between the Production Baseline and the Market Study cases is due to the subtraction of behind-the-meter solar profiles in the study load.

Supplemental Appendix 6: Hydro-Quebec Transactions

In the Market Study, interface flows from the corresponding Production Baseline days were held constant and not economically evaluated, except for Hydro-Quebec imports. Transactions flowing from the Hydro-Quebec zone and sinking into the NYISO were economically evaluated in the Day-Ahead and Real-time markets. Only Wheel-through transactions were held to the Production Baseline levels. This data file compares the sum of all flows (Imports and Wheels) in megawatts of capacity from Hydro Quebec between the production baseline and the study results.

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Table of Acronyms

Acronym	Definition
BPWG	Budget Priorities Working Group
CAISO	California Independent System Operator
CES	Clean Energy Standard
CRIS	Capacity Resource Interconnection Services
DAM	Day-Ahead Market
DER	Distributed Energy Resources
DNI	Desired Net Interchange
DPS	NY Department of Public Service
EAS	Energy and Ancillary Services
EFORd	Equivalent Demand Forced Outage Rate
EIS	Environmental Impact Statement
ESCO	Energy Supply Company
ESR	Energy Storage Resource
FCM	Forward Capacity Market
HQ	Hydro Quebec
ICAP	Installed Capacity
ICAPWG	Installed Capacity Working Group
IESO	Independent Electricity System Operator
IRM	Installed Reserve Margin
ISO	Independent System Operator
ISO-NE	Independent System Operator of New England
LBMP	Locational-Based Marginal Price
LCR	Locational Minimum Installed Capacity Requirements
MISO	Midcontinent Independent System Operator
MIWG	Market Issues Working Group
NYCA	New York Control Area
NY / NYS	New York / New York State
NYISO	New York Independent System Operator
NYSRC	New York State Reliability Council
PJM	PJM Interconnection LLC
PSC	NY Public Service Commission
REC	Renewable Energy Credit
RT	Real-Time
RTC	Real-Time Commitment
RTD	Real-Time Dispatch
RTM	Real-Time Market
RTO	Regional Transmission Organization
SCR	Special Case Resource
SCUC	Security Constrained Unit Commitment
SEP	State Energy Plan

Acronym	Definition
UCAP	Unforced Capacity
UDR	Unforced Capacity Deliverability Rights
WSR	Winter to Summer Ratio
ZEC	Zero Emission Credit