Memorandum

TO: NYISO Staff

FROM: David B. Patton, Pallas LeeVanSchaick, and Joseph Coscia

DATE: August 24, 2022

RE: MMU Review of 2021-2040 System & Resource Outlook

The System & Resource Outlook ("The Outlook") is the NYISO's primary economic planning study, providing detailed projections of transmission congestion from 2021 to 2040. The 2021 Outlook incorporates major enhancements to previous economic planning studies, with Policy Cases modeling achievement of the state's electricity sector goals under the Climate Leadership and Community Protection Act (CLCPA). The Outlook provides valuable information for market participants and policymakers on potential future trends in the NYISO system.

As Market Monitoring Unit for the NYISO, Potomac Economics is obliged to review the Outlook in accordance with Market Services Tariff 30.4.6.8.4. This memorandum presents analysis we performed using data from the Outlook and discusses implications for the NYISO markets. Following the Executive Summary, Section A discusses principles for evaluating whether regulated transmission is cost-effective. Section B summarizes the Outlook policy cases and presents our analysis of market incentives to address issues identified in the Outlook. Section C discusses potential enhancements for future Outlook studies and Section D provides our conclusions.

Executive Summary

As the NYISO focuses on accommodating New York State's policy goals in its planning processes, the Outlook will help identify where new transmission could reduce congestion and make renewable energy more deliverable. This memo shows how the Outlook also sheds light on how NYISO's wholesale markets can facilitate more efficient clean energy investments that reduce the need for regulated transmission investments.

The results in the Outlook underscore the importance of the locational siting decisions made by renewable and storage developers. These decisions can substantially affect the total costs of delivering new renewable output, as well as the location and value of transmission upgrades. Given these effects, it is essential that the market facilitate investment in efficient locations and that planners (including NYISO, utilities, and state agencies) identify transmission upgrades that are consistent with efficient siting decisions.

To illuminate these findings that can be drawn from the Outlook results, we introduce the following concepts for evaluating the locational aspects of investments in renewable and storage technologies:

- *Renewable Deliverability Ratio* – How much an increment of renewable capacity would affect the overall delivery of renewable energy as a share of its resource potential.[1]
- *Implied Net REC Cost* – The net cost of incremental renewable energy deliveries from an investment in generation, storage, or transmission.[2] This is useful for evaluating the cost-effectiveness of projects of different technologies and at different locations.

Figure 1 show the location of wind and solar project interconnection points in the Outlook S2 2030 and 2035 cases. For each dot, the color indicates the Renewable Deliverability Ratio of resources at that location, while the size indicates the MWs assumed to be added there.

Figure 1: Renewable Deliverability Ratios of Wind and Solar Projects

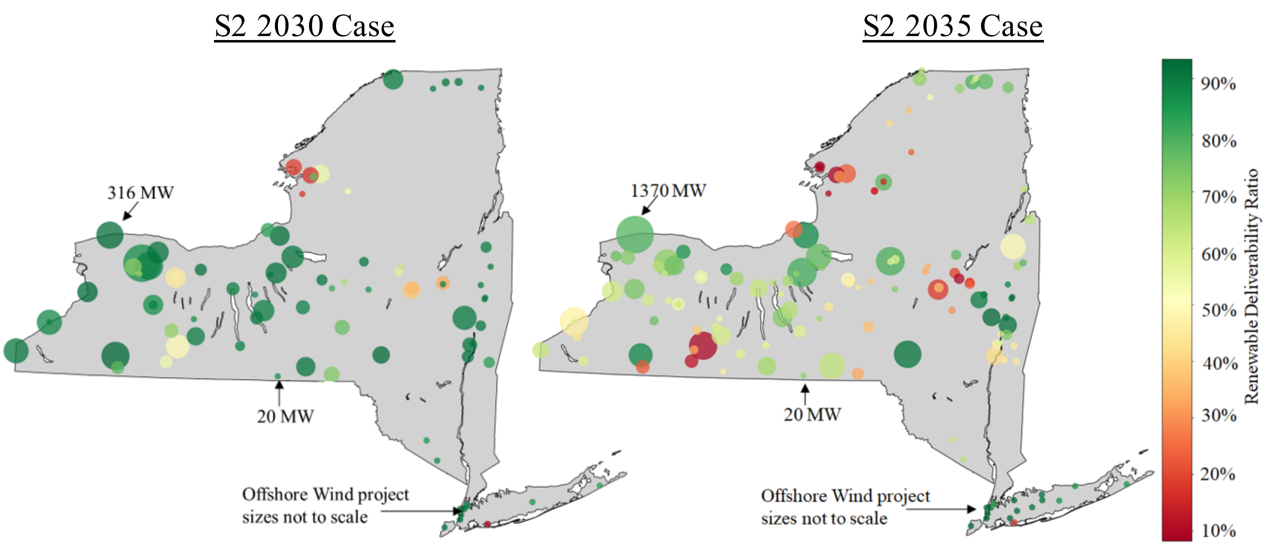

Figure 1 shows that the deliverability of renewable resources varies substantially by location, even in 2030. As more renewables are sited moving to 2035, many locations exhibit deliverability ratios less than 50 percent. Importantly, the market will not reward resources entering at these poorly deliverable locations because curtailments would be frequent and prices would often be low or negative. Market incentives to avoid over-saturated locations may reduce the value of transmission projects that assume a large amount of new capacity will enter at those locations. Hence, planners should be cautious when valuing long-term project benefits.

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1 For example, if a MW of a wind project is capable of producing 3,200 MWh annually but 300 MWh will be curtailed and the project will cause other renewables to be curtailed by 500 MWh, the Renewable Deliverability Ratio of the project is 75% = 2,400 MWh net renewable generation divided by 3,200 MWh of potential output.

2 The Implied Net REC Cost equals the average REC payment that a project would need to be economic, expressed in dollars per MWh of renewable energy that it can deliver without causing curtailment of other resources to increase.

Figure 2 summarizes the distribution of Implied Net REC Costs of individual projects by technology in the S2 case for 2030 and 2035. The charts show the median, maximum, minimum and quartile values of individual projects modeled for each technology. The figures include potential storage at locations where it would reduce curtailment in at least 500 hours per year.

Figure 2: Implied Net REC Costs by Technology

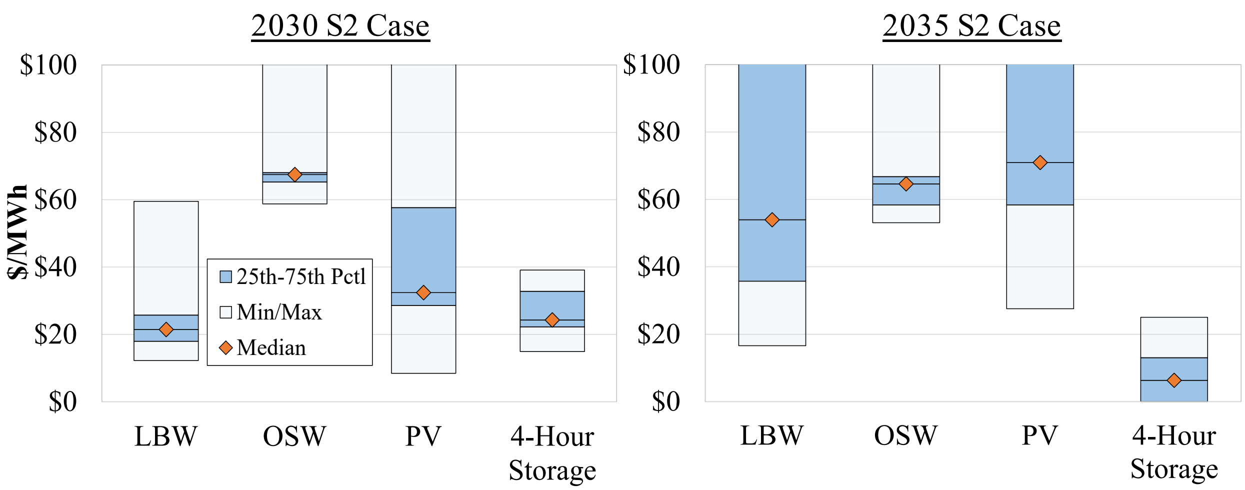

Figure 2 shows that the net REC costs vary significantly by technology and generally rise from 2030 to 2035 as large amounts of each resource enter and a higher share of each is sited at over-saturated locations. The one notable exception is the 4-hour storage resource.

In a high-renewable system, storage increases the supply of renewable energy that is deliverable to load by reducing curtailment that would otherwise occur. The Outlook's 2035 case shows that it would be much less costly to increase consumption of renewable energy by adding storage than by adding renewables. Rising penetration of intermittent renewable generation increases energy price variability, particularly when REC revenues encourage renewable generators to offer at negative prices, which makes storage more profitable.

Based on our analysis, we highlight the following key findings:

1. *Planners and policymakers should recognize that markets will provide strong and efficient incentives for renewables to site in relatively deliverable locations.* This lowers the costs of meeting carbon emission objectives.
   - Hence, planners should be cautious when identifying upgrades whose value depends on future developers choosing to site in oversaturated areas without regard for market signals, unless those areas have compelling advantages.
   - Transmission projects designed to unbottle specific constraints are more likely to be economic if selected: (a) to unbottle renewable generation with a high probability of entering service or (b) to facilitate investment in areas with superior land availability, resource potential, or special cost advantages.

2. *The Outlook underestimates the incentives for merchant storage to facilitate the delivery of renewable energy to the NYISO system.*
   - Storage can reduce renewable curtailments and lower the amount of renewable capacity needed to meet the state goals. NYISO market prices will strongly reward storage projects that reduce curtailment of renewables.[3]
   - Under-representing storage investment in the planning models increases the apparent need for transmission upgrades. We encourage planners to update their investment assumptions to reflect prevailing market incentives.
3. *Uniform pricing of clean energy would enhance market efficiency and improve the planning studies.* Inconsistent valuation of clean energy from comparable resources (such as through different REC payment levels) can undermine market efficiency.
   - REC payments play a key role in determining the incentive of renewable resources to run at different price levels and their associated offer prices.
   - A resource receiving higher REC payments may run inefficiently and contribute to more congestion while other less costly resources are curtailed because they are receiving lower REC payments.
   - In addition, the value of storage and transmission projects may be distorted if the renewable energy curtailments they reduce are not valued consistently.
4. *Inconsistent pricing of clean energy creates financial risk for early investors in renewables, which may ultimately discourage early investment.*
   - In Section D, we show that new renewables at some locations in the Outlook cases are more costly than they appear because they cannibalize RECs of resources that entered earlier with lower costs.
   - This creates a risk for existing renewable resources that their RECs will be priced below those of future projects. This discourages developers with the capability of entering quickly from investing.

A. Determining When Transmission Investment is Cost-Effective

The Outlook's policy cases find that transmission congestion and renewable curtailment will rise over time as renewable penetration increases. The Outlook's Key Findings assert a need for transmission to increase deliverability of renewable energy.[4] While regulated transmission investment is sometimes an efficient solution to reduce congestion and renewable curtailments, this is not always the case. Transmission congestion is a normal feature of a well-functioning electricity market and it is efficient to invest in transmission when the investment costs are lower than the incremental reduction in congestion.

[3] This is true of merchant storage projects and does not presume a need for a 'storage as transmission' model.

[4] See the August 8, 2022 draft Outlook report at page 17: "Transmission expansion is critical to facilitating efficient CLCPA energy target achievement. The current New York transmission system, at both local and bulk levels, is inadequate to achieve currently required policy objectives."

Hence, it is not efficient to eliminate all congestion. In fact, congestion provides valuable incentives for generation and storage developers to pursue projects that alleviate bottlenecks. Likewise, some renewable curtailment is likely to occur in an efficient market with high renewable penetration when the marginal curtailment costs are less than the transmission investment costs. Hence, projected future curtailment of renewables does not necessarily imply a need for regulated transmission investments.

Ultimately, planners should promote regulated transmission investment only when it is cost effective since inefficient transmission investment tends to crowd-out more cost-effective investments in generation and storage. A transmission project is an efficient means to increase renewable energy production only if its Implied Net REC Cost is lower than that of competing generation and/or storage projects.[5] Hence, we recommend that the NYISO and other planning processes that rely on the Outlook consider the Implied Net REC Cost as an important criterion when evaluating transmission solutions.

B. Analysis of Outlook Results

This section discusses our analysis of the Outlook results. The section begins with a discussion of several key inputs and findings from the Outlook. The remainder of the section describes an analysis of the Outlook results, including our evaluation of the economics of investment in new generation and storage resources.

1. The Outlook Policy Cases

The NYISO developed two Policy Cases in the Outlook, "S1" and "S2". Each case models a resource mix and load growth that are designed to satisfy the mandates of the CLCPA. These include 70 percent renewable generation by 2030, 100 percent zero-emissions generation by 2040, and electrification-driven load growth. The NYISO forecasted changes in the resource mix between 2021 and 2040 using the PLEXOS capacity expansion model, which selects the most economic combination of generator additions and retirements at a zonal level to satisfy state mandates while minimizing capital and operating costs. The NYISO then modeled the resulting resource mix in GE MAPS, which simulates hourly operations using a detailed representation of the NYISO transmission system. The cases included new transmission projects that have already been approved or awarded, but no additional economic transmission.[6]

Table 1 below summarizes intermittent renewable resources, battery storage and load in 2030 and 2035 in each Policy Case compared to the 2022 NYISO Gold Book. Both cases add approximately 9 GW of offshore wind by 2035 in line with state mandates. We focus on the 2030 and 2035 cases because the NYISO's 2040 cases did not enforce transmission constraints on lower-voltage lines and relied heavily on inclusion of a hypothetical "dispatchable emissions free resource" in the capacity expansion model.

5 The Implied Net REC Cost is the average REC price that would be needed to make a project economic for increasing renewable deliverability.

6 The NYISO modeled the Western New York and AC Public Policy Transmission projects, Northern New York, and the recently awarded Champlain-Hudson Power Express and Clean Path Express HVDC projects.

The S1 Case satisfies remaining CLCPA goals primarily by adding land-based wind, which is selected because it is the lowest cost resource in the capacity expansion model. The S2 Case uses alternative assumptions from the state's draft Climate Action Council scoping plan and adds a large amount of utility-scale solar, faster buildout of offshore wind, and higher total load.

Table 1: Summary of Renewable Resources and Load in Policy Cases

Case	2022 Gold Book	S1 Policy Case		S2 Policy Case	
	2022	2030	2035	2030	2035
Peak Load (GW)	32.8	35.2	41.7	30.1	35.1
Total Load (TWh)	156	162	185	164	205
Utility-Scale Solar PV (GW)	0.1	4.7	4.7	4.7	13.4
Behind-the-Meter Solar PV (GW)	4.3	10.1	10.8	9.5	11.6
Land-Based Wind (GW)	2.2	10.4	13.9	7.2	13.6
Offshore Wind (GW)	0.0	4.9	8.9	7.3	8.9
4-Hour Battery Storage (GW)	0.0	3.0	4.4	3.0	4.8

The Policy Cases find that while most renewable generation will be deliverable to load, transmission congestion will rise and cause renewable curtailments. In the S1 and S2 cases, 2.9 to 4.5 TWh (3.4 to 5.2 percent) of wind, solar and hydro generation is curtailed in 2030 and 8.9 to 9.2 TWh (7.5 to 8.0 percent) in 2035. Much of the curtailments in the Outlook occur in 'generation pockets' where local constraints limit deliverability to loads outside the pockets.

It is notable that the Outlook anticipates much lower rates of curtailment by 2030 compared to the '70x30' policy cases in NYISO's last economic planning study – the 2019 CARIS Phase I report. Curtailment of renewables in the 2019 CARIS 70x30 Case reached 9.2 to 13.1 TWh (9 to 11 percent) in 2030.[7] This reduction in forecasted curtailment is likely due to enhancements in modeling assumptions such as the use of economic capacity expansion to select new resources. This demonstrates how the choice of future renewable projects has a major impact on the value that transmission projects will provide through avoided curtailment.

2. Analytical Approach for Evaluating Investment Incentives

In the remainder of this section, we use data from the Outlook to examine how NYISO markets provide incentives for non-regulated responses to projected congestion and curtailment. We focus on the S2 Case because it features a resource mix more in line with current state plans.

Price Assumptions. Any analysis of investment will depend on assumed energy and capacity prices. For our analyses, we derived hourly LBMP data from the Outlook GE MAPS cases and adjusted it to estimate day-ahead prices using a historical benchmark case.[8] We conservatively

7 These values reflect the 'Base Load HRM' and 'Scenario Load HRM' CARIS 70x30 cases, which modeled the impacts of 3 GW of energy storage.

8 This adjustment is necessary because MAPS produces a flatter price curve than the NYISO energy market. Our approach is similar to the one described in Section A of the Technical Appendix to our review of the 2019 CARIS Phase I study, available here.

assume capacity prices in line with estimated going-forward costs of existing thermal units.[9] We estimate capacity credit for each resource type and zone based on its marginal reliability contribution using each cases' resource mix.[10] The cost of entry for new resources is derived from NREL's 2022 Annual Technology Baseline and is similar to the values used in NYISO's capacity expansion model.

To illuminate how investment incentives vary by technology and location, we calculate the following values:

- *Renewable Deliverability Impact* – The annual renewable output that would be facilitated by an incremental MW of a particular technology.
  - For renewable generators, this is the annual output of the incremental resource minus incremental curtailment of other renewable generators.
  - For storage, this is the reduction in renewable energy curtailments because the storage resource is charging to absorb renewable output that is otherwise undeliverable.[11]
- *Implied Net REC Cost* – The cost of increasing consumption of renewable generation from an investment, based on: investment costs, market revenues, and the Renewable Deliverability Impact of the investment. This metric combines two categories of cost:
  - Investor's Required REC – The average REC price that the project owner would need to recover its levelized costs, net of energy and capacity market revenues.[12]
  - Indirect REC Cost Increases – the value of foregone RECs from existing units who experience increased curtailments due to the new unit. Developers tend to pass on these costs to end-users in the form of higher REC prices. (This category is not applicable to storage resources because they reduce curtailment.)

Renewable Deliverability Impact allows planners and policy makers to quantify the effects of incremental investments on renewable energy utilization. The Implied Net REC Cost allows them to evaluate the cost-effectiveness of different technology and project locations on these renewable policy goals. We use these concepts to evaluate renewable generation in Part 3 of this section and energy storage investments in Part 4.

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9 Assumed 2030 capacity prices are $55/kW-year (NYCA and G-J Locality), $110/kW-year (NYC), and $65/kW-year (Long Island). These prices are held constant in 2035, adjusted for 2 percent annual inflation.

10 We estimate marginal reliability contribution using a simplified resource adequacy simulation of the NYISO system. Our approach is similar to the one described in our 2021 Capacity Accreditation Consumer Impact Analysis, available here (see slides 5-9).

11 Losses in the charge/discharge cycle are subtracted. We determine charge/discharge pattern of the marginal storage unit using an economic storage dispatch model based on day-ahead prices.

12 For storage, this is equivalent to the average negative price during hours when the battery charges to reduce renewable curtailment that would make the storage project economic. Hence, if a storage project has a Net Implied REC cost of $20/MWh and nearby renewables offer -$20/MWh when they are curtailed, the storage project will be economic based on market prices.

3. Analysis of Renewable Generation Investments

Figure 3 and Figure 4 summarize the marginal deliverability of renewable resources in the S2 Case. Each bar represents a location where a new renewable resource was assumed. The height of the bars shows the renewable technology's modeled capacity factor at each location. The dark blue bars show the renewable output that is deliverable on a net basis, while the gold bars show the portion of the output that would cause curtailment. The Renewable Deliverability Ratio of each project is equal to the blue bar divided by the combined height of the blue and yellow bars.

Figure 3: Marginal Energy Deliverability and Curtailment of Renewables, 2030 S2 Case

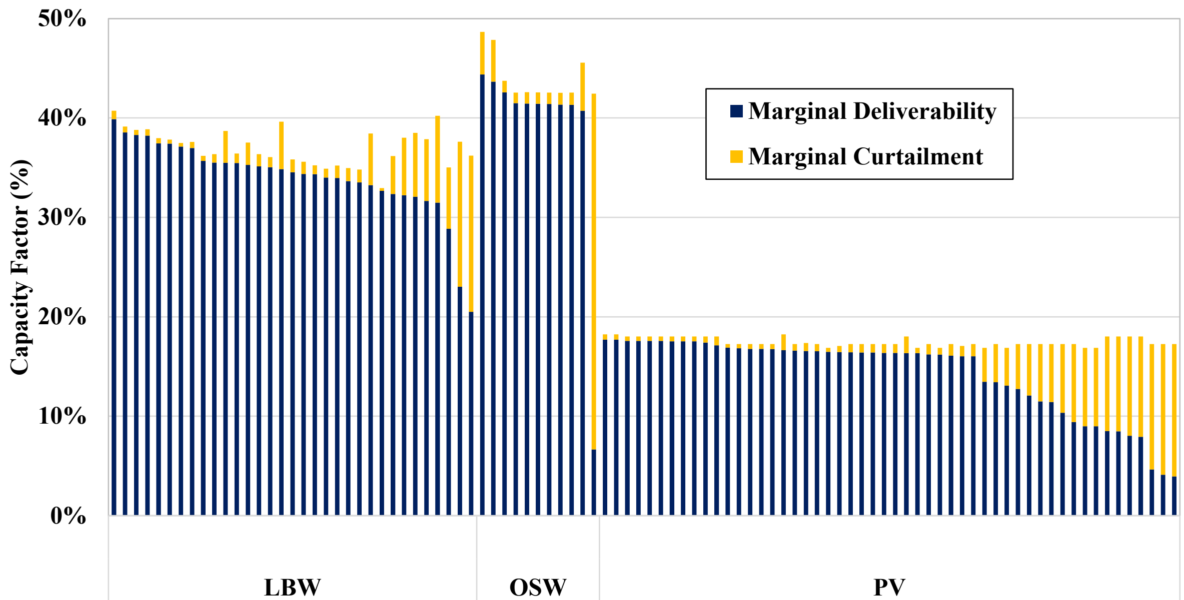
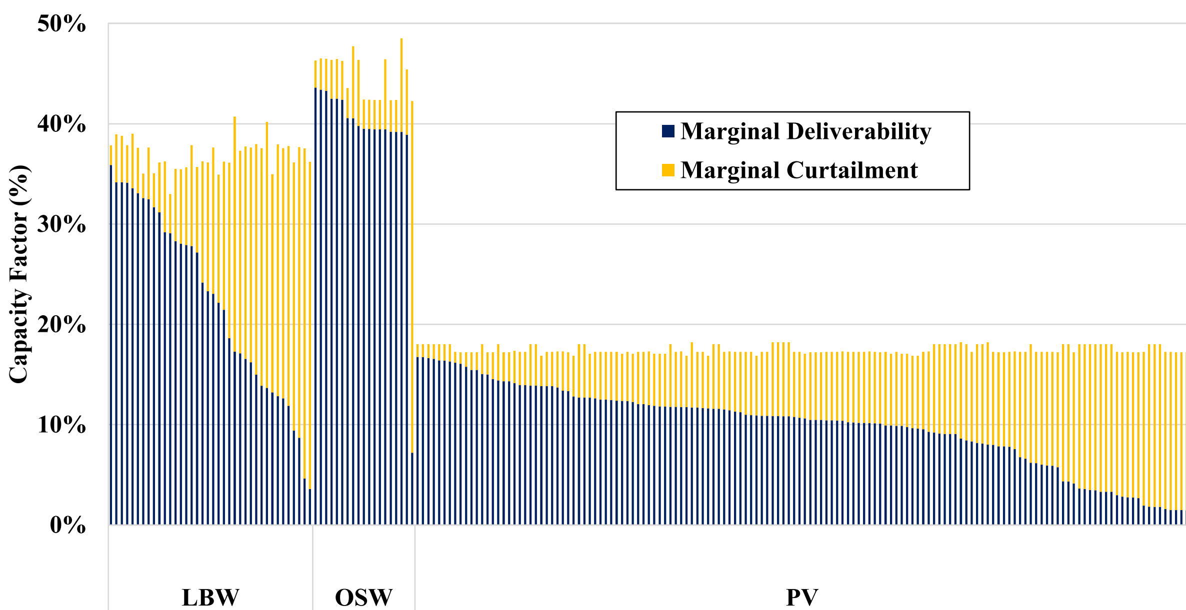


Figure 4: Marginal Energy Deliverability and Curtailment of Renewables, 2035 S2 Case



These figures show that individual projects and technologies vary considerably in terms of their deliverability and the curtailments they would cause. These differences in deliverability correspond to a wide range of Implied Net REC Costs. The wholesale market provides developers with strong incentives to avoid making investments at locations that would increase curtailment. Market prices provide these incentives because resources at oversaturated locations would generally be uneconomic and uncompetitive in REC solicitations. It is reasonable to expect that as resources enter the system, congestion patterns will emerge that will discourage subsequent projects from building in the most constrained locations.

Considering the low Renewable Deliverability Ratios at many locations in the S2 2035 Case, it is likely that changing the location of renewable resources would reduce curtailments and increase renewable deliverability. For example, the S2 case includes 239 MW of wind at Bennett 115 kV in Zone C (in the "Z1" pocket) by 2030 and 771 MW of wind at this node by 2035, based on the capacity expansion model. Wind at this location has a 56 percent Renewable Deliverability Ratio in 2030, falling to 10 percent in 2035. Many other locations across the upstate region have much better Renewable Deliverability Ratios, indicating that it might be more efficient for some of the 771 MW of wind capacity modeled at Bennett 115 kV to be built elsewhere.

In practice, factors such as land availability, permitting considerations and site-specific costs can cause developers to pursue projects at congested locations. Other locations with high deliverability may be inaccessible or costly. Hence, curtailment will not be completely avoided by incentives to interconnect at uncongested sites. However, market incentives will guide investors to avoid undeliverable projects that do not have offsetting advantages and pursue projects with lower Implied Net REC costs before less economic sites. The Outlook identifies several areas where renewable deliverability is likely to be low. The value of transmission projects designed to unbottle these areas will depend on the amount of renewable capacity that ultimately enters there and its timing, which may be difficult to predict.

Implied REC Costs. Figure 5 and Figure 6 summarize the Implied Net REC Cost of new renewable investments in the S2 Case. Each bar represents a location where a renewable resource was modeled, sorted in descending order of Implied Net REC Cost. The dark lower bars show the Investor's Required REC, while the lighter bars show the Indirect REC Cost Increases. The Indirect REC Cost Increases result when a new investor receives a higher REC price than an existing unit that will be curtailed more, thereby cannibalizing the REC of the existing generator. When a new generator cannibalizes the REC of an existing generator, the direct cost is borne by the existing generator in lost REC revenue. However, to the extent that developers anticipate this before signing a REC contract, they will seek to recover these costs through higher REC payments in other hours. Thus, consumers will ultimately bear the costs.

These results show that the Implied Net REC Cost is higher than the Investor's Required REC at many locations, implying that new entrants can profit by securing higher-priced REC contracts than existing renewables and cause them to be curtailed. The difference between the top shaded bars and the lower solid bars in Figures 7 and 8 represent REC value that a new resource would cannibalize from existing resources without actually increasing renewable generation. This analysis suggests that paying different REC prices will lead to inefficient curtailments and investment incentives. Projects with a low Investor's Required REC but high Implied Net REC

Cost may be economic in REC solicitations only because they can undercut existing resources. Differing REC prices can also lead to different prices at curtailment locations (i.e., prices that are more negative at high-REC locations). This will distort investment incentives for storage at these locations because the magnitude of the negative prices substantially affect investment incentives for storage resources.

Figure 5: Implied Net REC Costs by Technology, 2030 S2 Case

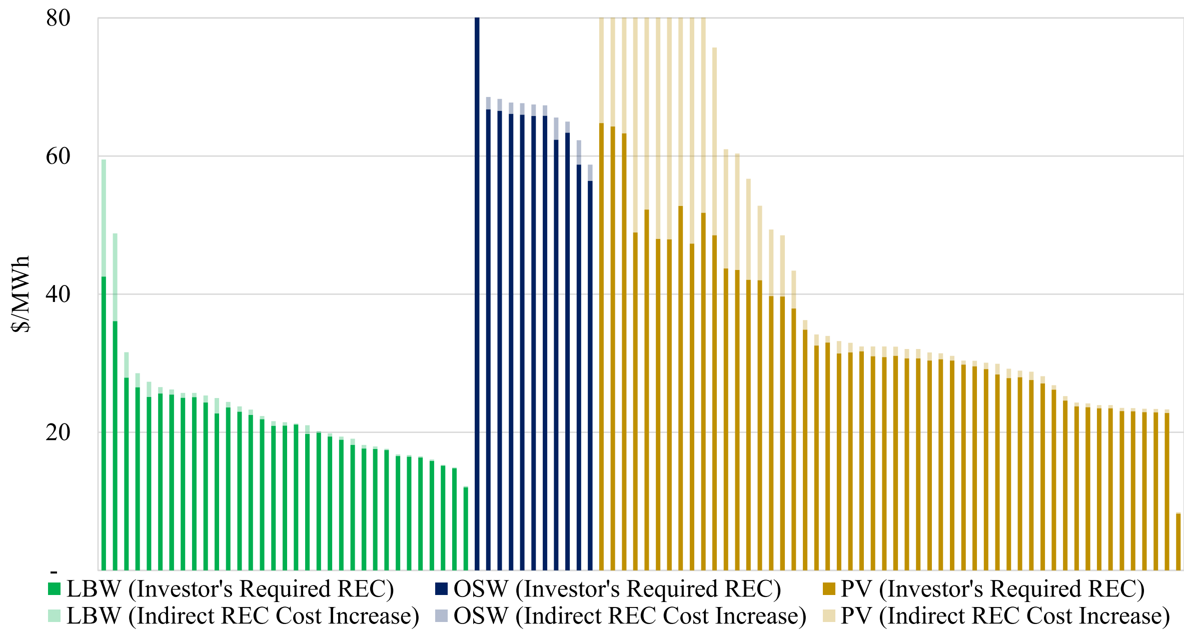
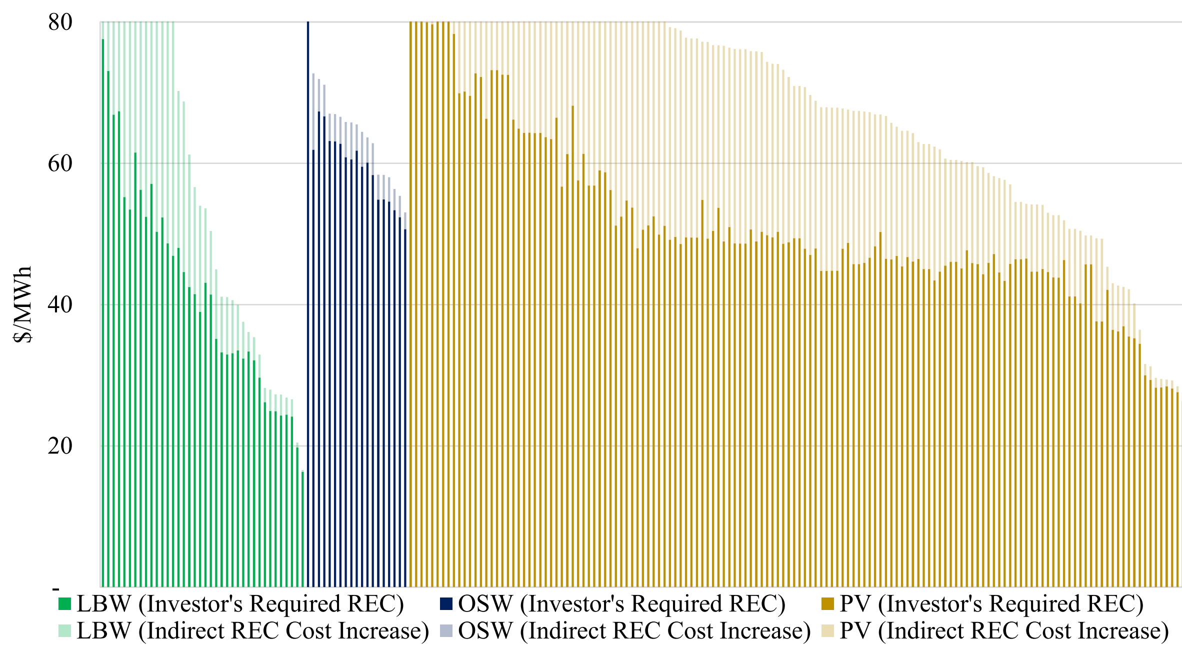


Figure 6: Implied Net REC Costs by Technology, 2035 S2 Case



4. Analysis of Energy Storage Investments

This section provides an assessment of the incentives to invest in storage resources. The figures in this section summarize marginal energy deliverability, market revenues and implied REC costs of storage resources in the S2 Case.

Renewable Deliverability Impact. Figures 7 and 8 show the Renewable Deliverability Impact of 4-, 6-, and 8-hour storage at locations where renewable resources were modeled in MAPS. The Y-axis shows the annual reduction in curtailment of renewables from adding 1 MW of storage. Comparing the results in these figures for storage resources to the comparable results for renewable resources demonstrates that storage resources at many locations are more effective than renewable resources at facilitating increased deliveries of renewable energy to load.

For example, a storage resource with a Renewable Deliverability Impact of 1,200 MWh provides the same incremental renewable energy to load as a renewable resource with a 14 percent capacity factor. In the 2030 S2 Case, the Renewable Deliverability Impact of storage is high at a subset of locations where Renewable Deliverability Ratios are poor. By 2035, the Outlook suggests that the Renewable Deliverability Impact of storage is high at many locations because of the increasingly widespread curtailment of renewables at these locations.

Figure 7: Renewable Deliverability Impact of Storage, 2030 S2 Case

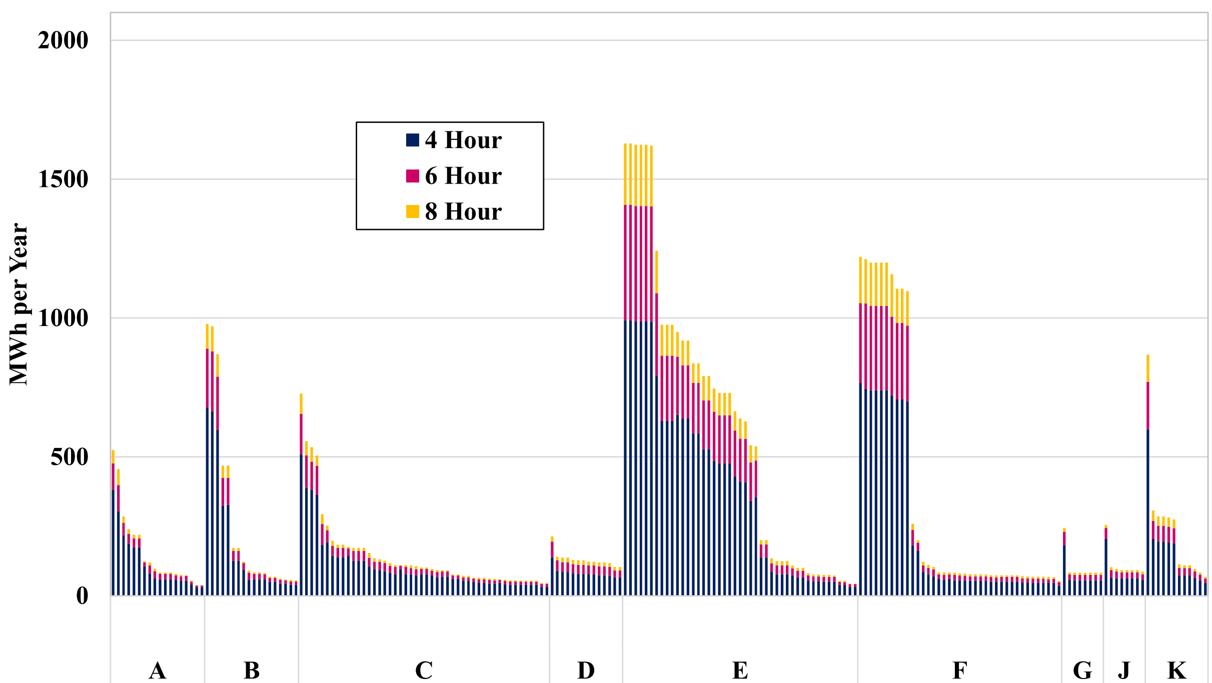
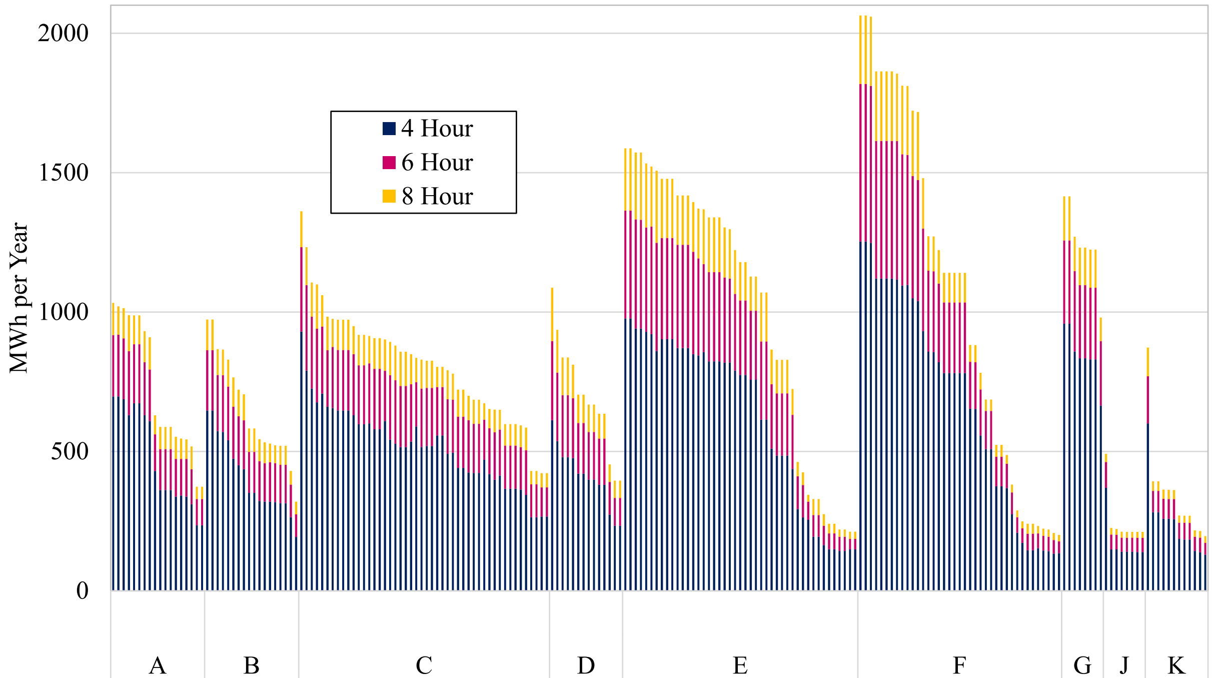


Figure 8: Renewable Deliverability Impact of Storage, 2035 S2 Case



Storage Net Revenues. Figures 9 and 10 show net energy, reserve and capacity revenues of a 4-hour storage resource at locations where renewable resources were modeled in MAPS, compared to the Gross Cost of New Entry (CONE) of a 4-hour battery. Revenues that the battery earns by charging when the price is negative because of renewable curtailments are shown separately from other energy market revenues.

Widespread renewable curtailments create favorable market conditions for investment in storage resources. These figures show that:

- In the 2030 S2 Case, additional storage would be economic based on market prices at some locations. These are generally locations where frequent curtailments and negative pricing provide substantial revenues for batteries that charge to reduce the curtailments.
- By 2035, additional storage beyond the 4.7 GW assumed in the S2 Case is economic based on market prices at a large number of locations. The revenues available to storage at these locations are supported not only be their renewable deliverability impacts, but also by higher overall energy price volatility under the high renewable penetration.
- In both the 2030 and 2035 cases, storage is most economic in upstate areas with low Renewable Deliverability Ratios. In contrast, storage is least economic in Zone J where offshore wind has higher Renewable Deliverability Ratios.

Figure 9: 4-Hour Storage Net Revenue, S2 2030 Case

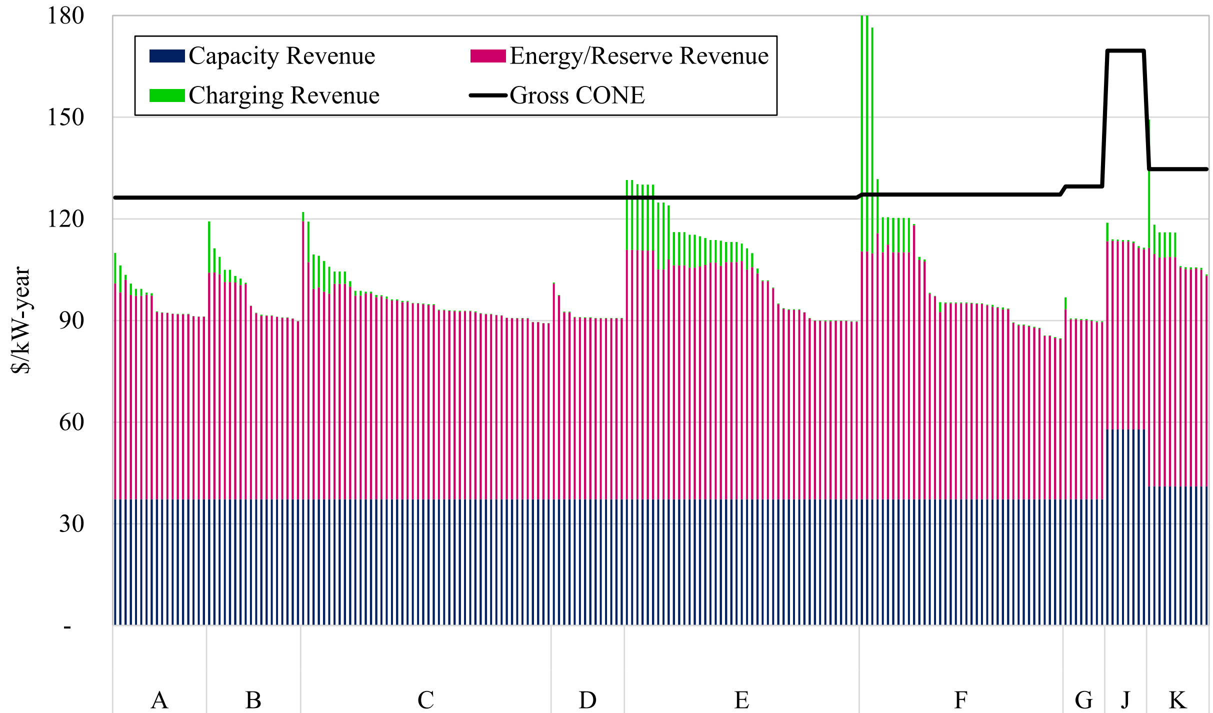
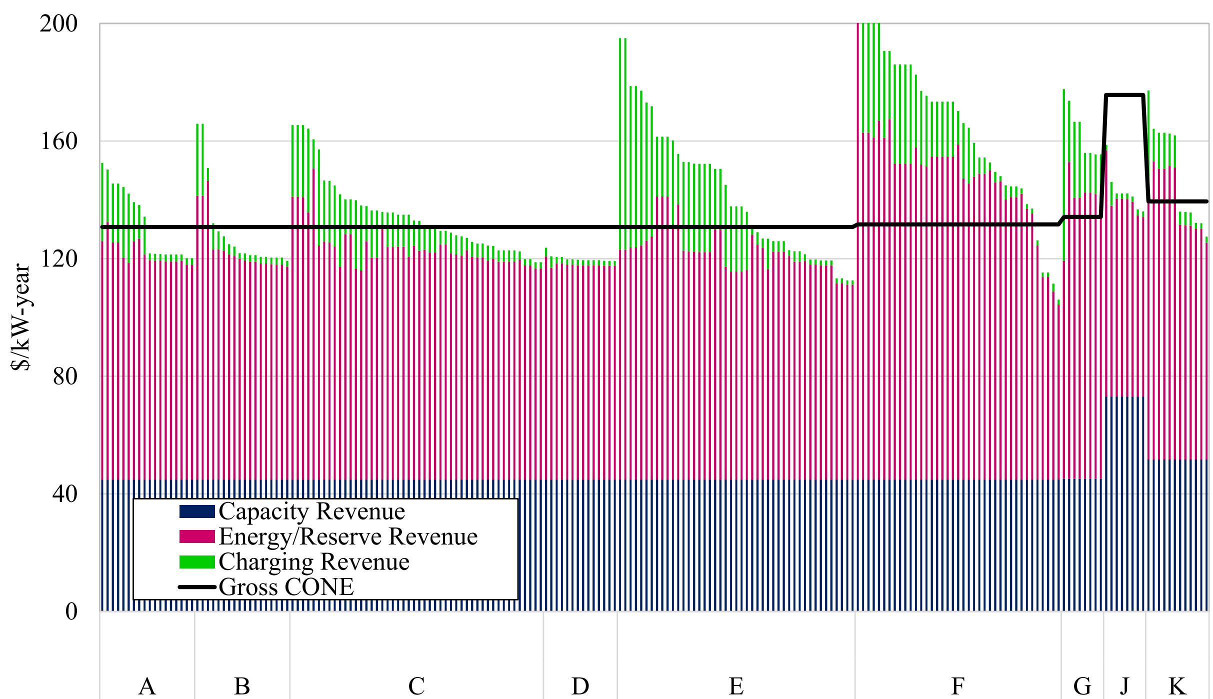


Figure 10: 4-Hour Storage Net Revenue, S2 2035 Case



Figures 11 and 12 show the Implied Net REC Cost of 4-hour storage at locations with a marginal energy deliverability of 500 MWh/year or more. If curtailed renewables cause average negative prices to be lower than this value, storage is economic based purely on market revenues.

Figure 11: 4-Hour Storage Implied Net REC Cost, S2 2030 Case

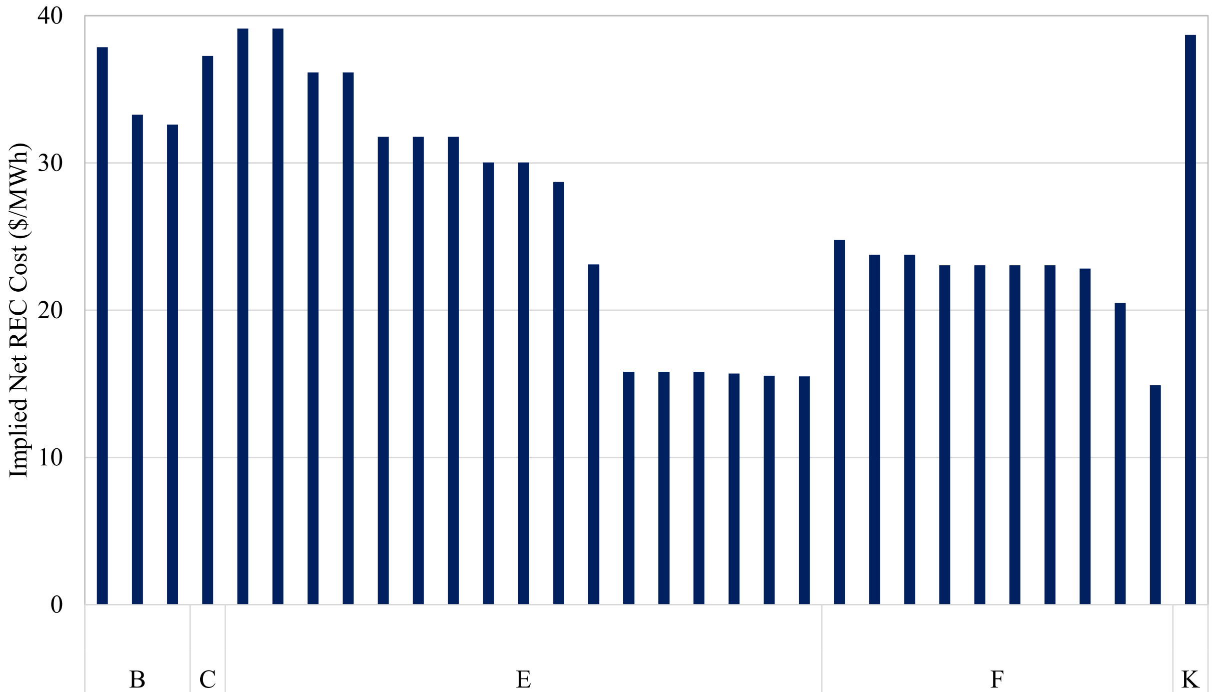
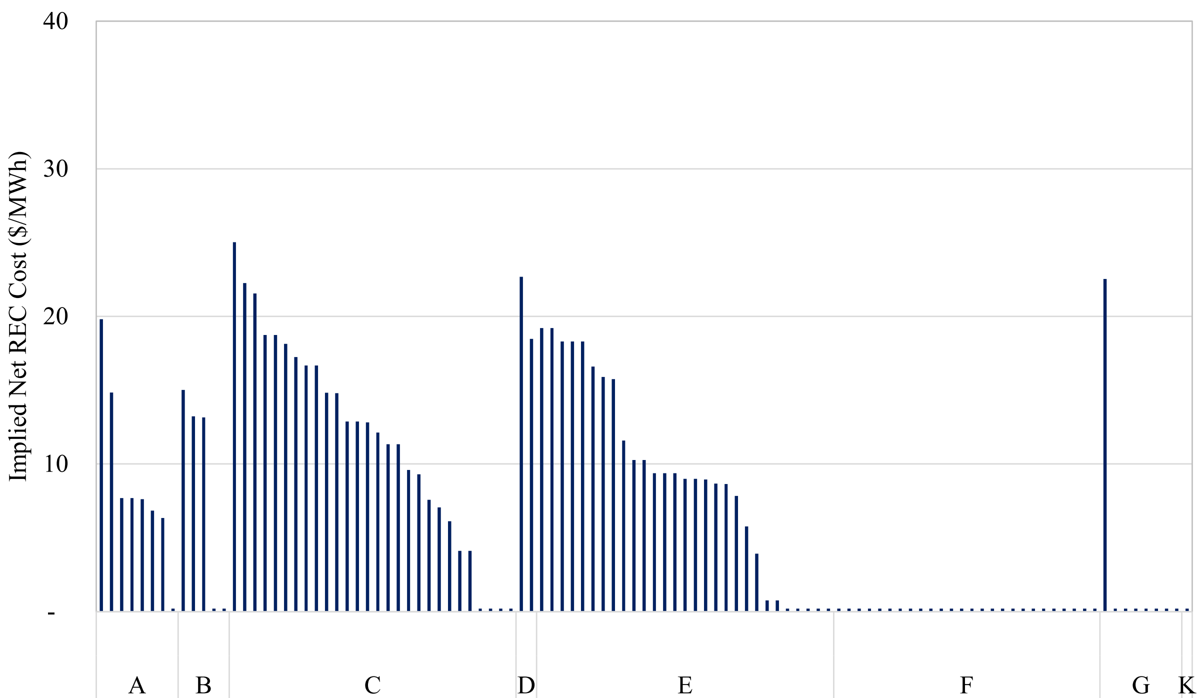


Figure 12: 4-Hour Storage Implied Net REC Cost, S2 2035 Case



These figures show that additional storage is an efficient means to increase the delivery of renewable energy to load:

- In the 2030 S2 Case, the Implied Net REC Cost of 4-hour storage ranges from $15/MWh to $39/MWh (with a median value of $24/MWh) at 32 locations with Renewable Deliverability Impact of at least 500 MWh.
- By 2035, the Implied Net REC Cost of 4-hour storage ranges from $0/MWh to $25/MWh (with a median of $6) at 107 locations with Renewable Deliverability Impact of at least 500 MWh.

These costs are competitive with the Implied Net REC Costs of new renewables at some locations in 2030 and significantly less costly than renewables at most locations by 2035. This suggests that the amount of storage in the Outlook is inefficiently low in 2035. A resource mix with more storage and less renewable capacity could satisfy the same clean energy goals at lower cost and with less curtailment than the resource mix modeled in the Outlook S2 case.

Finally, this analysis demonstrates NYISO market prices provide strong incentives for investors to pursue storage projects that provide high Renewable Deliverability Impact. When storage resources charge to relieve curtailment of renewable resources that earn REC payments, the value of the REC is passed through to the storage owner via negative prices. As a result, the NYISO market outcomes alone provide efficient incentives for storage investment at locations where the average REC price paid to nearby curtailed renewables is greater than the Implied Net REC Cost of storage. This is the case because the REC price causes the renewable resources to offer at negative prices that will set the LBMPs when they are curtailed.

C. Potential Enhancements for Future Outlook Studies

The Outlook policy cases are the product of considerable efforts by the NYISO to improve on prior studies and are the most sophisticated forecast to date of how state policies will affect the NYISO system. However, to the extent that the Outlook is used for planning purposes, it is important to recognize the limitations of its assumptions and methodology. We highlight the following limitations of the 2021-2040 Outlook, which point to potential enhancements for future studies.

1) The Outlook models did not fully consider economic incentives for renewable development. It assumed that new renewable resources interconnect at project locations in the current interconnection queue. It did not consider whether the resulting mix of locations is economic or whether a different mix would be more attractive to developers.

The Outlook determined the capacity, technology, and zone of new additions using the Capacity Expansion Model, which did not model congestion and prices at the nodal level. These resources were then assigned to a set of buses in MAPS derived from the interconnection points in the current NYISO interconnection queue. In some cases, the NYISO reassigned capacity away from buses with extremely high curtailment to a nearby location. However, the Outlook models generally were not designed to optimize the resource mix considering the marginal deliverability or market revenues of resources modeled in MAPS.[13]

Optimizing the locations of new capacity is challenging because considerations other than transmission congestion – such as land availability and permitting considerations – affect developers' decisions. An 'optimized' buildout which ignores these factors is likely to produce unrealistic results. However, the NYISO did not have detailed site-specific information on these factors when developing the Outlook models, and it may not be possible to obtain such information. Hence, the NYISO relied on the interconnection queue as an indication of where developers are most likely to pursue projects in the future. This approach is reasonable given the NYISO's limited information, but runs the risk of relying too heavily on the current queue:

- Most projects in the interconnection queue never reach completion. Development-stage projects eventually face higher economic scrutiny when seeking investment capital.
- The amount of capacity modeled at some interconnection sites in the MAPS cases exceeds the amount proposed in the queue by 2035, because a large amount of additions are needed to satisfy state goals.[14] Future projects may not enter at the same locations as current projects.
- Because the S1 and S2 cases both rely on the queue, they have significant overlap in the locations of renewables, especially for wind. Of the 34 buses where land-based wind derived from the capacity expansion results was modeled in either the S1 or S2 case in 2035, 31 included exactly the same amount of new wind capacity in both cases.

Hence, we recommend that NYISO develop a sensitivity case in future Outlook studies that evaluates the impact of changes in resource locations. For this case, the NYISO should relocate new capacity determined by the Capacity Expansion Model from MAPS nodes with very low incremental Renewable Deliverability Ratios to nodes with higher deliverability. This process should include shifting capacity from one pocket or zone to a different pocket or zone while holding the total generation from renewable resources constant. This 'optimized' case would provide information on how much curtailment could be averted or deferred by alternative siting decisions. Planners could combine this with information about the feasibility of the 'optimized' locations relative to the Policy Case when considering how the value of transmission projects is likely to be affected by market incentives.

2) The Outlook models underestimated the potential for storage to increase consumption of renewable energy. The Outlook models included economic additions of energy storage, but they did not fully capture the economics of using storage to reduce congestion and curtailment:

13 The NYISO tested an approach that limited capacity expansion additions by technology and zone considering areas where high curtailment occurred in MAPS. The NYISO did not pursue this approach for the final policy cases as initial results primarily increased the addition of DEFRs. The 'optimized' case approach we propose in this section differs from this approach because we propose to alter the interconnection points of renewable resources in MAPS, rather than altering the total capacity of renewables using the capacity expansion model.

14 For example, there is 392.5 MW of wind proposing to interconnect at the Bennett 115 kV bus in the NYISO queue as of July 31, 2022. The S1 and S2 Outlook cases both model 771 MW of wind at this bus in 2035.

- Storage additions were derived from the capacity expansion model, which is a zonal model that represents generation and load using monthly average six-hour time slices. Because the capacity expansion model does not have hourly granularity or nodal representation, it underestimates price volatility at many locations and consequently undervalues storage, likely causing the amount of storage selected by the models to be inefficiently low.
- The MAPS cases modeled storage on a distributed basis across all load buses within each zone, rather than at specific interconnection points. The charge and discharge pattern of storage was modeled based on the timing of zonal net load. Batteries located at particular high-curtailment locations (i.e., co-located with renewables) would likely follow a different charge/discharge pattern to relieve curtailment of those resources. Hence, the models likely underestimated the ability of the storage capacity it includes to reduce congestion and curtailment.
- The capacity expansion model considered additions of 4-hour storage, but not longer duration resources, such as 6- or 8-hour batteries. Longer duration storage resources have higher capacity value and might cost-effectively provide peaking capacity in the long term while reducing curtailment of renewables.

3) The Outlook models did not consider how intermittency will affect procurement of ancillary services. It is likely that large additions of intermittent resources will drive a growing need for flexibility provided by reserve and regulation products. Requirements for system flexibility will affect the dispatch and curtailment of generation and storage resources, the utilization the transmission network and the economics of investments. For example, the loss of offshore wind output could become the largest contingency in downstate zones. GE MAPS has limited ability to model ancillary services, and it was beyond the scope of the 2021 Outlook to model how reserve requirements would be affected by changes in the resource mix. Hence, we recommend that NYISO consider approaches to modeling ancillary services requirements and how they affect unit commitment and dispatch in subsequent Outlook studies. This may require consideration of alternative production cost modeling software.

4) Results driven by modeling assumptions. The Outlook models relied on forecasts derived from currently known assumptions, which are unlikely to accurately predict how economics and policy will shape the long-term NYISO resource mix.

Any long-term forecasting exercise, such as the models developed for the policy cases, rely on a large number of assumptions that are subject to change. For example, the S1 case forecasts no additional utility scale solar beyond projects that had already received awards from NYSERDA as of 2021, and the S2 case forecasts none until after 2030. But as the 2021 Outlook neared completion, NYSERDA announced in June 2022 that the winners of its latest solicitation include 2.4 GW of solar resources. This suggests either that a large number of projects with state REC awards are not economic and will not enter service, or that the Outlook underestimated future solar development compared to wind. Many other key factors affecting the modeled resource mix are likely to change, such as the costs of different resources or the federal incentives they receive. Uncertainty regarding the realism of resource mix assumptions should encourage caution when planning regulated projects whose value is driven by long-term model predictions.

D. Conclusions and Recommendations

The 2021 Outlook is a major improvement to NYISO's previous planning studies and provides important insights on the potential impacts of state policies on the NYISO system. The reduction in projected curtailment of renewables in 2030 from 9-13 TWh in the 2019 CARIS 70x30 Case to 3-5 TWh in the Outlook policy cases demonstrates the major impact that modeling assumptions and methodologies have on the value of transmission in planning studies.

Our review of the Outlook demonstrates how NYISO markets can reduce or defer the need for regulated transmission by guiding investment in renewables to more deliverable locations and encouraging investment in merchant storage. We highlight the following recommendations:

Recommendations for Future Outlook Modeling Enhancements

1. Model procurement of ancillary services in production cost models, considering how future needs will be driven by resource mix changes. Consider adoption of different production cost modeling software if needed to accomplish this.
2. Perform an 'optimized' production cost model sensitivity case in which renewable capacity in locations with high marginal rates of curtailment is relocated to locations with lower marginal rates of curtailment.[15]
3. Improve modeling of energy storage to more accurately estimate the benefits of storage in the capacity expansion and production cost models.[16]
4. Include options for 2-, 6- and 8-hour storage in the Capacity Expansion Model.

Recommendations for Transmission Planners (including NYISO, utilities, and state agencies)

5. Estimate the Implied Net REC Cost of proposed regulated transmission projects and compare it to market-based alternatives including merchant battery storage and renewables. This will indicate if the transmission project is a cost-effective means to increase the supply of RECs to load compared to other investments.
6. Exercise caution when evaluating benefits of transmission projects whose value is strongly linked to uncertain long-term generator siting decisions.

Recommendations for Policymakers

7. Price incremental clean energy from new and existing renewables in a uniform manner so that environmental goals can be satisfied in a more cost-effective manner.

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15 See discussion in Section C.1.

16 Specifically, we recommend (a) modifying storage costs in the capacity expansion model to offset under-valuation of its benefits due to lower locational and temporal granularity, and (b) modifying the siting and dispatch pattern of storage in MAPS to more realistically minimize renewable curtailment based on market incentives. See discussion in Section C.2.