Illinois Power Agency Policy Study

Aurora Production Cost Modeling

prepared for

The Illinois Power Agency

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1 Production Cost Modeling Inputs

Public Act 103-0580 directs the IPA to evaluate the wholesale electricity price impacts, the net rate impacts on Illinois ratepayers, the impacts on carbon and other pollutant emissions, and the impacts on the state's decarbonization goals of the policy proposals identified in the Act and in SB 1587. The Agency utilized production simulation modeling to evaluate these impacts. In the present context, production simulation modeling can answer questions regarding the impacts on wholesale electricity prices, emissions and changes to the generation resource mix in Illinois over the modeling horizon.

Production cost simulation models are widely used in the electric power industry to support decision making involving investments in new generation and storage facilities, assess the impact of policy making, and analyze the cost of environmental regulations. Simulation models show how the subject electric system can be expected to operate over a specific time horizon. These models start with inputs that define the structure and operation of a regional electric system in terms of generation resources, costs, loads, and operational characteristics as well as existing environmental and other regulatory considerations. The modeling system then simulates how the electric system will operate given those inputs.

The models typically use an algorithm that draws on the database to simulate the operation of the system in a least cost manner, that is the lowest cost resources are operated first up to the total amount of resources required to generate the electricity that is needed to meet the electric system load. The simulated operation is subject to the various constraints such as transmission limits and plant operating characteristics.

Aurora, a chronological dispatch simulation model licensed from Energy Exemplar, was utilized to forecast power market outcomes, including energy prices, capacity prices, power plant emissions, and natural gas demand for electric generation. The default database provided by Energy Exemplar was used as a foundation for the modeling inputs. Energy Exemplar's database is augmented with extensive customization based on public data sources and modeling experience. Aurora was used to model the impact of three policy proposals:

1. Offshore wind project in Lake Michigan,
2. The SOO Green HVDC transmission line and associated renewable energy to energize it, and
3. Energy storage systems

Each of the individual policy proposals were included in a "but for" test that compared power market outcomes against a Base Case without the resources against a modeling run with the resources in place. A combined case with all three policy proposals enacted was also modeled. A comparison of the simulation results with the base case provides a picture of how these additions would change the way the electric system operates, the mix of generation resources and the cost of generating electricity. The Aurora modeling was run with 2025 through 2050 as the study period.

Assumptions in the Base Case represent "known and knowable" expectations for Illinois and other states' energy policies. The modeling included the specific state policy measures and goals that have been announced, such as procurement targets for large-scale clean energy technologies and settled state procurements. The modeling inputs for MISO relied primarily on Series 1A MISO Futures modeling conducted by the Regional Transmission Organization ("RTO") for long-term planning purposes, specifically Future ~~1~~1A. The Futures refresh modeling includes three Future scenarios, referred to as ~~1,~~

~~2~~1A, 2A, and ~~3~~3A, that incorporate a range of load and resource assumptions. Future ~~1~~1A includes the most conservative modeling approach to decarbonization but incorporates the latest generation changes contemplated in utility Integrated Resource Plans ("IRPs").[1] ~~The working Base Case for PJM was developed~~In comments on the draft Policy Study, the Illinois Clean Jobs Coalition ("ICJC") recommended the use of Future 2A as the core scenario of the Policy Study.[2] Future 2A represents a more aggressive decarbonization path compared to Future 1A and is the middle option in the Futures Scenarios. The aggressive resource expansion found in Future 2A assumes significant leaps in MISO's resource mix occur before the projects supported by the policy proposals studied through this Policy Study are even in service. For example, MISO Future 2A includes 23 GW of "flex" resources in MISO North/Central (3 GW in Illinois) *by 2027*, despite the flex resource representing no specific technology in particular.[3] Several commentors on the draft Policy Study expressed concern regarding the use of this sort of proxy unit in the Policy Study modeling; having a wide proliferation of flex resources across the study region before those new projects have been placed into service is unrealistic, rendering any modeling across the 2030-2049 period unreliable. In the IPA's view, Future 1 resource additions can be expected with greater certainty and more often reflect queued and planned projects grounded in progress from ~~publicly available documentation as described further below.~~developers and utility planning (for example, only 14 GW of "model-built" resources are built in Future 1A, as opposed to 169 GW in Future 2).[4] The large influx of near-term model-built resources in Future 2A may be unrealistic, with 64 GW built by 2030.[5]

The working Base Case for PJM was developed from publicly available documentation as described further below.

On February 15, 2024, IPA posted workpapers to provide additional information to stakeholders regarding the input assumptions memorialized below.[6]

In this report all dollar values, unless otherwise noted, are conveyed in nominal dollars. In some instances real dollars, or constant dollars, are used.[7] Real dollars are adjusted for their purchasing power in a given

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[1] See F1 for a description of assumptions in MISO's Series 1 modeling for Future 1:

MISO Futures One Pager538214.pdf (misoenergy.org)

[2] ICJC comments, pp.5-6. ICJC Power Sector Committee Comments on Energy Storage Components of the IPA Draft Policy Study (illinois.gov)

[3] "These 'Flex' units are proxy resources that refer to a non-exhaustive range of existing and nascent technologies, representing potential generation that is highly available, highly accredited, low- or non-carbon emitting, and long in duration. As a proxy, potential Flex resources could be, but are not limited to: reciprocating internal combustion engines (RICE units), long-duration battery (>4 hours), traditional peaking resources, combined-cycle with carbon capture and sequestration, nuclear SMRs, green hydrogen, enhanced geothermal systems, and other emerging technologies." MISO Futures Report, Series 1A, published November 1, 2023. See pages 2-3. Series1A_Futures_Report630735.pdf (misoenergy.org)

[4] Model-built resources are selected by MISO's capacity expansion model, unlike planned resources that are expected to be built per a survey of MISO members.

[5] *Id*., pages 54-55.

[6] Draft Policy Study Supporting Information (illinois.gov)

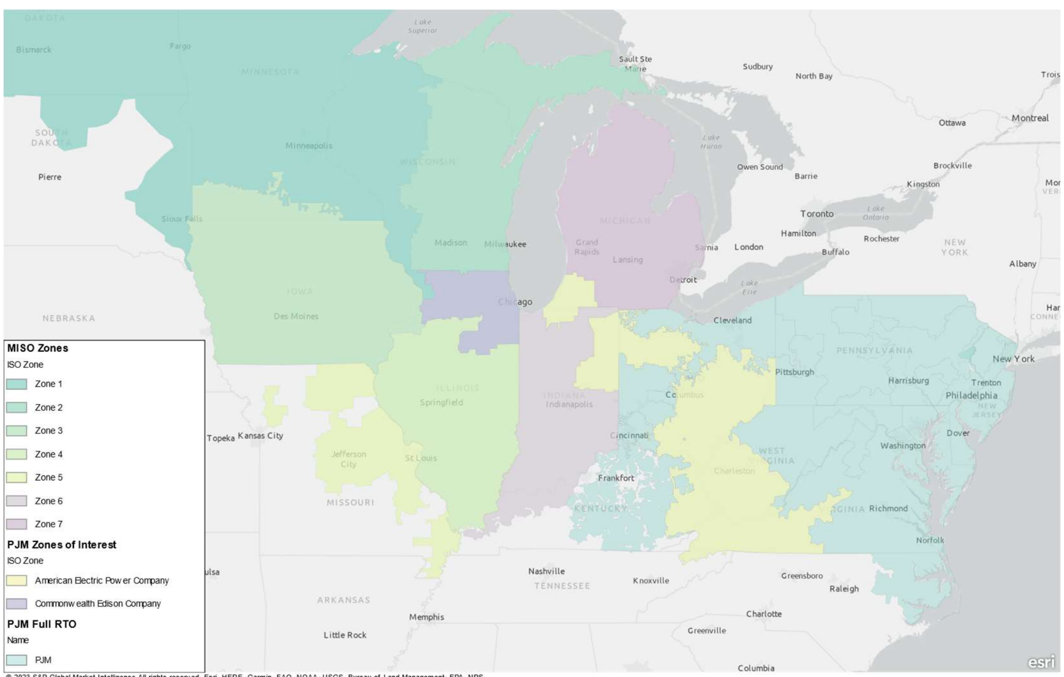
[7] United States Census Bureau, Current versus Constant (or Real) Dollars, accessed February 27, 2024.

Current versus Constant (or Real) Dollars (census.gov) year, usually (and in this analysis) controlling per inflation. The long-term inflation assumption used in this analysis was 2.5% for converting constant dollar values to nominal values, consistent with the NREL Annual Technology Baseline ("ATB"). Given the long time horizon for this study, the compounding effect of inflation means that a nominal dollar in the beginning of the study period is likely to be worth more in real dollar terms than a nominal dollar at the end of the study period.

1.1 Study Region

Aurora is utilized in a zonal configuration with the study region modeled to include MISO (North/Central) and Western PJM. The RTOs are further divided into zones to capture transmission constraints within each RTO. MISO was modeled with each of the seven Local Resource Zones (LRZs) that are part of the North/Central regions. PJM's ComEd and AEP transmission zones were modeled individually. The rest of Western PJM was aggregated into a single zone, and the eastern transmission zones in PJM were aggregated into Rest of MAAC, Eastern MAAC, and Southwest MAAC zones. This approach reduced computational burdens and detailed study of transmission constraints that are more than a "wheel" or two away from Illinois.

Figure 1: Map of Study Region[8]



Limited interface data sources for MISO, prevented the modeling of separate boundary flows into MISO N/C from MISO South for some ties, such as TVA. Where feasible, boundary flows with other regions (including MISO South, IESO, among others) were modeled based on an average weekly profile for each month using three years of historical flow data (168 hours by 12 months, 2020-2022).

[8] Map generated with S&P Capital IQ.

1.2 Transmission Transfer Limits

Inter-zonal transmission transfer limits are defined using several publicly available data sources:

- MISO Loss of Load Expectation ("LOLE") Working Group Materials (Seasonal Capacity Import Limits and Capacity Export Limits)[9]
- PJM Base Residual Auction ("BRA") Planning Parameters[10]

These sources represent emergency transfer limits that may be used during particularly tight system conditions. In PJM, these limits are adjusted to reflect operating data provided as PJM Day Ahead Interface Flows and Limits.

In cases where data are not available or data sources conflict, the analysis relies on the default settings provided by Energy Exemplar, as well as the professional judgment of the modeling team, to determine appropriate limits. Energy Exemplar performs a nodal power flow simulation that informs the zonal transmission transfer limits. ~~The default database defines linkages between MISO's Local Balancing Authorities as well as PJM's Transmission Zones.~~ The IPA reached out to MISO to request zonal transfer limits and other modeling information related to the Futures 1A study, but MISO was not able to provide any additional information due to data confidentiality concerns. PJM does not provide zonal transfer limits (or feedback on such limits) to outside groups. Energy Exemplar's nodal simulations are typically built off power flow cases that RTOs do make available to stakeholders. The default database defines linkages between MISO's Local Balancing Authorities ("LBAs") as well as PJM's Transmission Zones. In comments on the draft Policy Study, SOO Green requested that the final study include details on inter-zonal transfer limits assumptions. In support of this request, SOO Green provided vendor data for historical export flows from PJM to MISO.[11] Due to the proprietary nature of the Energy Exemplar base Aurora database, the limits of specific zonal links in the model cannot be disclosed, but aggregate information from the model run was used as a comparison to the vendor-sourced flow information.

[9] The latest import and export limits are posted here: https://cdn.misoenergy.org/20231017%20LOLEWG%20Item%2004%20PY%202024-25%20Final%20CIL-CEL%20Results630536.pdf

[10] PJM identifies Capacity Emergency Transfer Limits (CETL) in BRA planning parameters, found here: PJM - Capacity Market (RPM)

[11] SOO Green Comments on Illinois Power Agency Policy Study, see page 13. 20240213-soo-green.pdf (illinois.gov)

Figure 2: Export Flows from PJM to MISO, Peak Comparison by LBA

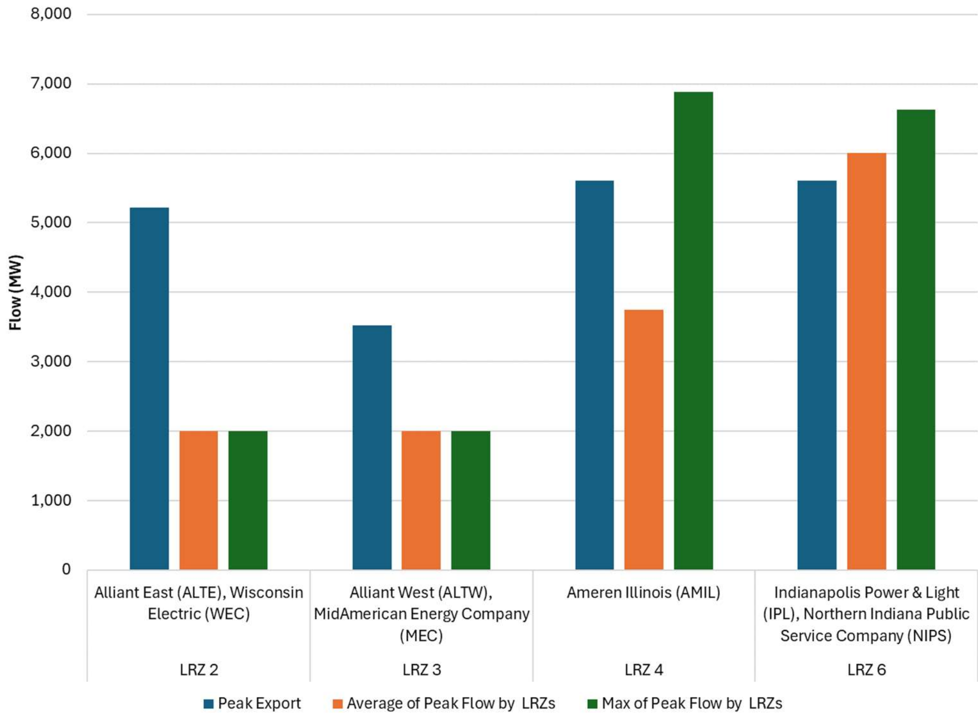
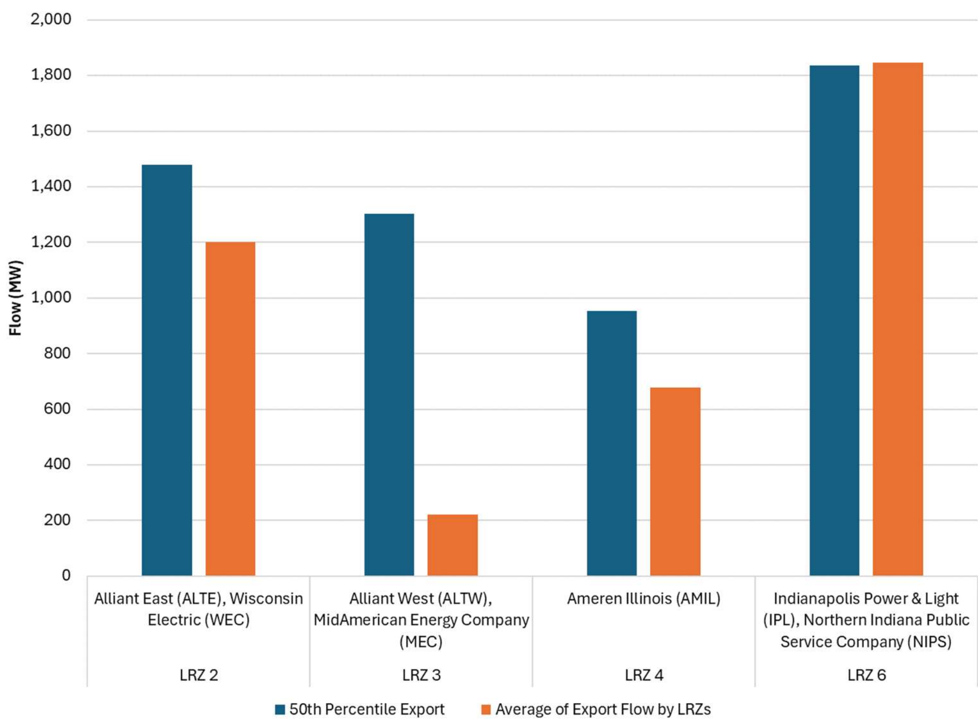


Figure 3: Export Flows from PJM to MISO, Comparison by LBA



Aurora's modeled flows cannot be disaggregated into LBAs. LRZ 4 flows from ComEd include Ameren Illinois (AMIL) and City Water Light & Power (CWLP), but the latter LBA is not included in the table provided in SOO Green's comments. Maximum flows into LRZ4 from AEP and ComEd were added together to be conservative, although we cannot identify the coincident maximum flow across the combined links due to data output limitations. In LRZ 6, in addition to Indianapolis Power & Light (IPL) and Northern Indiana Public Service Company (NIPS) flow into Duke Energy Indiana (DEI) from American Electric Power (AEP). Average of peak flow represents the average of each peak flow in a given year. Max peak flow is the maximum observed flow across the full study period.

Table 1: Export Flows between PJM and MISO, Comparison by LRZs[12]

2020-2023 PJM Export Flows to Select MISO Zones (MW)						*Aurora Flows Output (MW)*		
LRZ	**MISO Zone Receiving PJM Exports**	**Peak Export**	**90th Percentile Export**	**70th Percentile Export**	**50th Percentile Export**	**Average of Export Flow by LRZs**	**Average of Peak Flow by LRZs**	**Max of Peak Flow by LRZs**
2	Alliant East (ALTE), Wisconsin Electric (WEC)	5,217	2,593	1,894	1,480	1,202	2,000	2,000
3	Alliant West (ALTW), MidAmerican Energy Company (MEC)	3,527	2,099	1,645	1,304	222	2,000	2,000
4	Ameren Illinois (AMIL)	5,606	1,996	1,343	954	1,273	4,747	7,888
6	Indianapolis Power & Light (IPL), Northern Indiana Public Service Company (NIPS)	5,605	2,607	2,166	1,836	2,489	8,502	9,450

The modeling team notes that aggregated LRZ flows may include flows between additional MISO LBAs, so higher max flow from PJM into LRZ4 and LRZ6 is not necessarily an indication of faulty transfer limits.

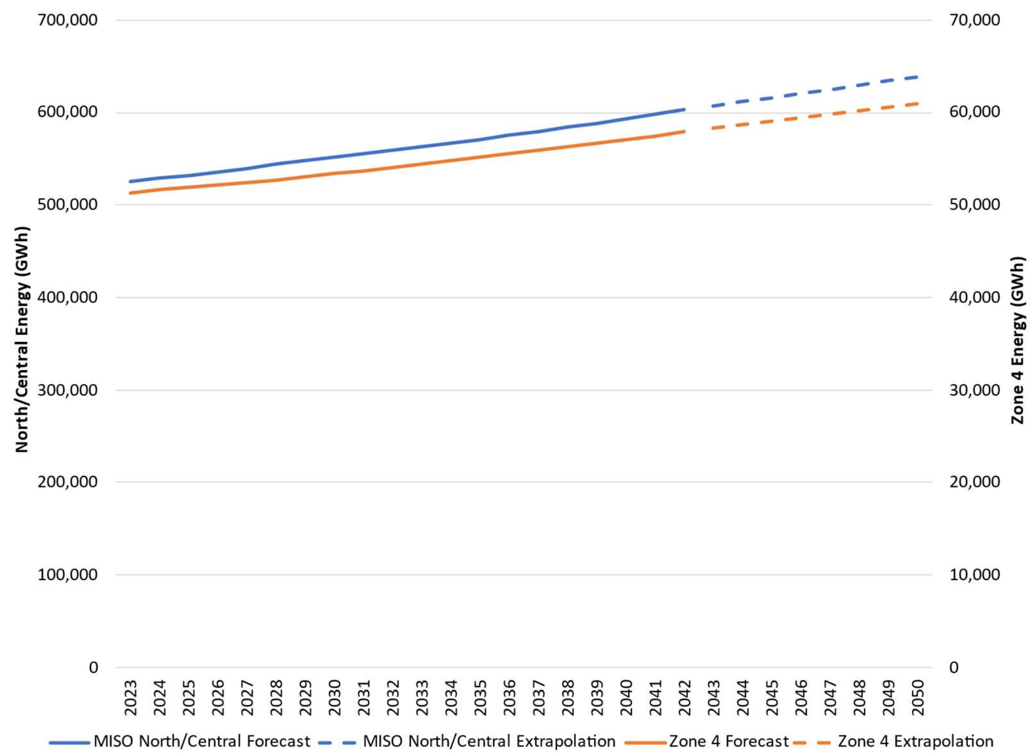
1.3 Demand Forecast

RTO planning documents were relied upon as the basis for peak and annual energy forecasts. MISO has published hourly and summary level load data for the Series 1A MISO Futures in meeting materials for the Long Range Transmission Planning ("LRTP") Workshop.[13] The Series 1A Futures forecast load through 2042. Future 1 forecasted load was extrapolated through 2050 assuming exponential growth consistent with the Combined Annual Growth Rate ("CAGR") over the forecast. The 2042 hourly load shape is applied to the remaining years in the forecast.

[12] Flow output was sampled across 2025-2050 modeled years.

[13] Long Range Transmission Planning (LRTP) Workshop (misoenergy.org) See April 28th meeting.

Figure 4~~2~~: Annual Energy Forecast, MISO[14]



PJM's 2023 Load Forecast Report data includes monthly metered and peak load values by zone through 2035. The load forecast for the rest of the study period was extrapolated by reconstituting the net energy for load through adding back in behind the meter ("BTM") solar generation. Net energy for load was extrapolated forward assuming exponential growth consistent with the CAGR over the forecast.[15] PJM does not provide an hourly demand shape, so 2011 historical demand was the shaping factor input into Aurora.[16] The PJM 2011 shaping profile is drawn from PJM estimates of unrestricted load with solar addbacks, adjusted to account for some missing data and anomalies via a review of metered load.[17] BTM solar, which is separately defined in PJM planning documents, is defined as a supply-side resource in order

[14] Zone 4 is made up of three Local Balancing Authorities based in Illinois: Ameren Illinois (AMIL), City Water Light & Power (CWPLP), and Southern Illinois Power Cooperative (SIPC). See Table 56.

Independent Energy and Peak Demand Forecasts to the Midcontinent Independent System Operator (MISO) (purdue.edu)

[15] Some CAGR sampling adjustments are made to zones to account for transient changes in demand that individual utilities request (see load-forecast-supplement.ashx (pjm.com) pp 18-22 and other observed near-term growth that is inconsistent with long-term trends.

[16] 2011 is used as the historical year for shaping as data sources are available to generate renewable profiles for this weather year, and limited BTM solar was in service that could skew the shape applied to gross load. 2011 weather year data is also available in NREL's WIND Toolkit database which is the source for wind resource data.

[17] See https://www.pjm.com/planning/-/media/FA6652A369C14A3CA9F1FFAE57CA88A5.ashx for the primary source and Data Miner 2 (pjm.com) for metered load utilized as a backstop.

to reflect the changes to the hourly shape of net load that solar creates, as solar generation does not track demand. BTM solar generation is assumed to grow at a constant MWh rate per the last year's forecasted growth rate. Load growth in PJM at large is mainly driven by the development of data centers in Virginia. BTM solar growth outpaces gross load growth in the extrapolated years.

Modeling assumptions used in this study were finalized prior to the release of PJM's 2024 Load Forecast Report. In that report, the updated load forecast significantly increased, by about 14.5% on a net energy basis by 2038, the last shared forecast year in the two reports.[18] The forecast for ComEd increased by 12.6% over the same period. Notably ComEd's load increase is lower than the full PJM RTO.

Table 2: PJM Load Forecast Comparison

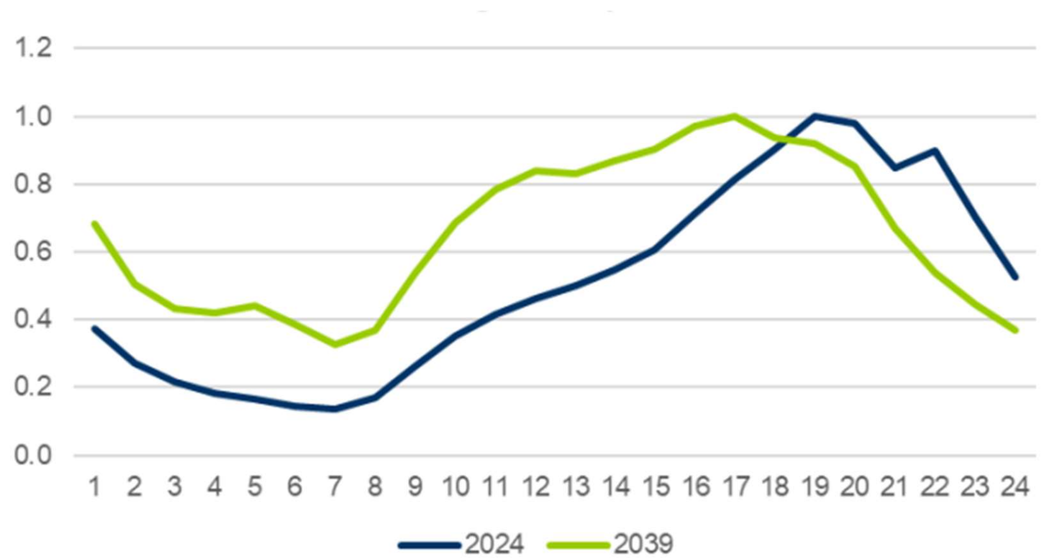
Energy (GWh)	**Market**	**2030**	**2038**	**Source**
2024 Forecast	ComEd	94,557	101,528	Table E-1 2024
2023 Forecast	ComEd	91,157	90,253	Table E-1 2023
% Change	ComEd	3.73%	12.49%	(2024 Load / 2023 Load) - 1
Energy (GWh)	**Market**	2030	2038	
2024 Forecast	PJM	952,578	1,099,538	Table E-1 2024
2023 Forecast	PJM	878,461	960,428	Table E-1 2023
% Change	PJM	8.44%	14.48%	(2024 Load / 2023 Load) - 1
Summer Peak (MW)	**Market**	2030	2038	
2024 Summer Forecast	ComEd	20,204	21,005	Table B-1 2024
2023 Summer Forecast	ComEd	19,888	19,481	Table B-1 2023
% Change	ComEd	1.59%	7.82%	(2024 Load / 2023 Load) - 1
Summer Peak (MW)	**Market**	2030	2038	
2024 Summer Forecast	PJM	167,873	187,752	Table B-1 2024
2023 Summer Forecast	PJM	157,899	167,567	Table B-1 2023
% Change	PJM	6.32%	12.05%	(2024 Load / 2023 Load) - 1
Winter Peak (MW)	**Market**	2030	2038	
2024 Winter Forecast	ComEd	15,196	16,267	Table B-2 2024
2023 Winter Forecast	ComEd	14,625	14,487	Table B-2 2023
% Change	ComEd	3.90%	12.29%	(2024 Load / 2023 Load) - 1
Winter Peak (MW)	**Market**	2030	2038	
2024 Winter Forecast	PJM	152,870	173,502	Table B-2 2024
2023 Winter Forecast	PJM	141,280	150,555	Table B-2 2023
% Change	PJM	8.20%	15.24%	(2024 Load / 2023 Load) - 1

[18] The most recent forecast for the RTO wide is 1,099,538 GWh, compared to 960,428 GWh in the previous report. The ComEd net energy forecast is 101,528 GWh, compared to 90,253 GWh in the previous report. The new report is here: The new report is here:

2024-load-report.ashx (pjm.com)

Portions of the peak demand increase that PJM is positing may be mitigated by changes to EV charging behavior. PJM Load Forecast Subcommittee materials indicate that the impact of additional EVs to the forecast adds around 20 GW to the summer and winter peak forecasts by 2038.[19] While PJM's consultant did modify EV charging profiles for light-duty vehicles over time to levelize charging throughout the day later on in the forecast period, charging overnight is still fairly low.

Figure ~~5~~3: Light-Duty EV Charging Profile, PJM Load Forecast Supplement[20]



While the new long-term forecast trajectory is heavily driven by demand from data centers and electric vehicles, whose long-term penetration is subject to uncertainty, this additional information means that the modeling results may be conservative with respect to the benefits of the policy proposals.

Additional efficiencies from smarter charging may allow PJM to mitigate more of the peak load contribution from electric vehicles.

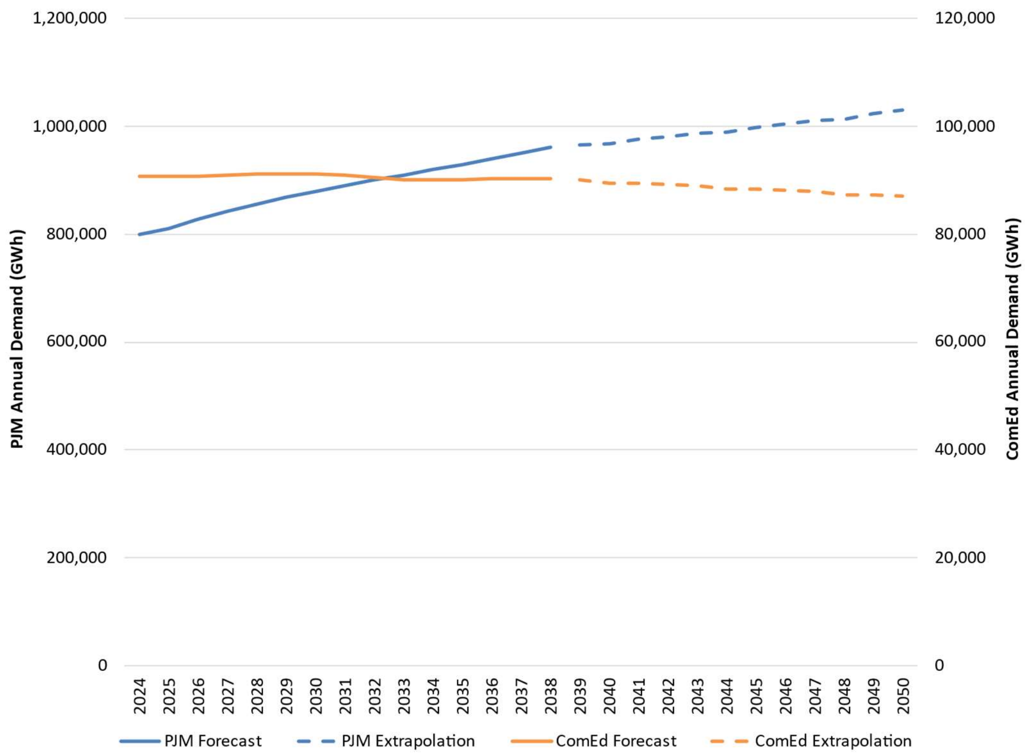
Changing the electricity demand (particularly given a change of this magnitude) requires cascading changes throughout the modeling cycle. Extrapolation of load beyond the forecast period must consider whether utility-nominated adjustments to the PJM base load forecast will be transient or permanent. The load forecast permeates many other aspects of the study, namely capacity expansion. The large increase in load in PJM's latest forecast requires a full review of siting assumptions for new renewable and conventional technologies in order to meet resource adequacy and environmental goals across PJM, and would likely require substantial iteration to ensure appropriate results. While Dominion Virginia has released IRPs detailing how they will meet increased load requirements driven by data center growth, other vertically-integrated utilities in PJM have not yet considered how to manage heavy increases in demand. The new sources of load that PJM has identified do not have the same hourly patterns as

[19] 2024 Preliminary PJM Load Forecast, November 27, 2023 presentation to the Load Analysis Subcommittee by Molley Mooney. See slides 39 and 46. 20231127-item-03---2024-preliminary-pjm-load-forecast.ashx

[20] PJM 2024 Load Forecast Supplement, January 2024, page 18. load-forecast-supplement.ashx (pjm.com)

traditional demand sources, so additional review of hourly profile information would also be required for any updated modeling.

Figure 6: Annual Energy Forecast, PJM



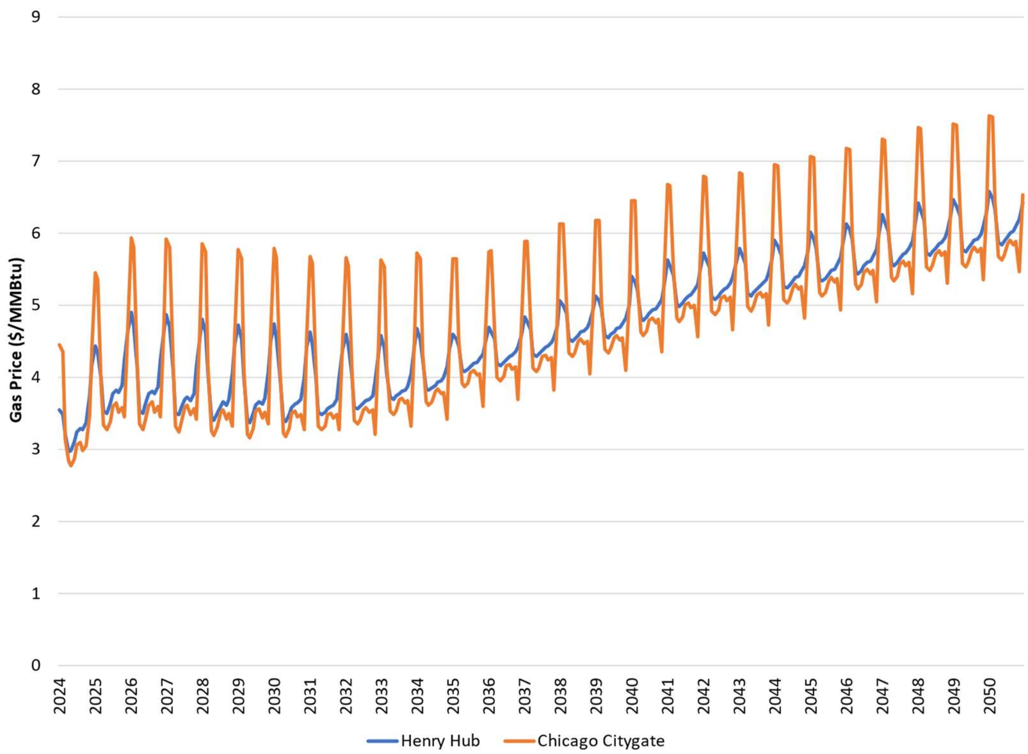
1.4 Fuel and Allowance Price Forecasts

Fuel prices, as delivered to generators, are forecasted for natural gas, oil products, and coal. Nuclear generators are price takers and do not have much dispatch flexibility. Therefore, nuclear fuel prices are ignored with the assumption that nuclear plants run fully-loaded aside from scheduled refueling.

1.4.1 Natural Gas Price Forecast

The forecast of delivered natural gas prices started with NYMEX Henry Hub futures and basis projections from S&P Market Intelligence. NYMEX Henry Hub futures are available through 2035. For the years 2036 and beyond, prices were escalated annually based on the forecasted annual growth rates of the average price from EIA's 2023 Annual Energy Outlook ("AEO"), Reference and High Oil and Gas Supply cases. Basis projections are generally constant after a few years, which reflects the lack of liquidity in basis futures markets past the prompt year and significant volatility in pricing due to weather variability.

Figure 74: Monthly Delivered Gas Prices

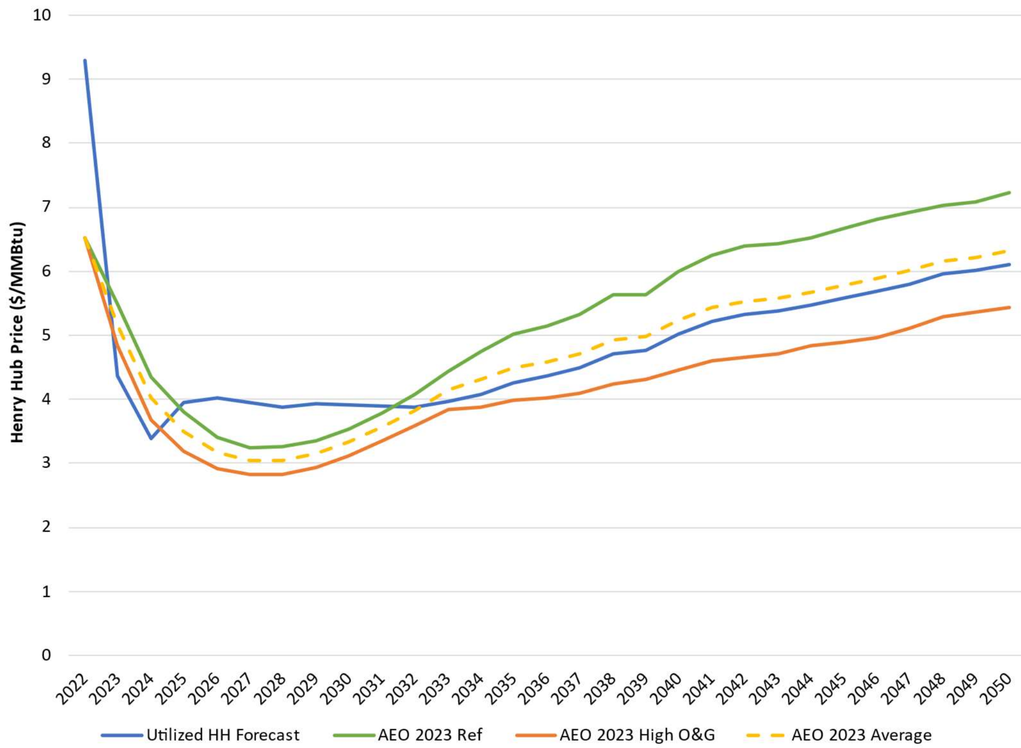


In comments on the draft Policy Study, SOO Green asserted that the gas commodity price forecast used is relatively low due to the use of futures data rather than fundamentals modeling. The commenter recommended the use of a fundamentals model rather than the use of futures pricing, and recommended the use of the 2023 AEO Reference Case.[21] Comments by the Energy Storage Associations echoed this critique.[22] The gas price forecast was a blend of futures and fundamentals via its use of the 2023 AEO. Averaging the 2023 Reference and High Oil and Gas Supply Cases yields a similar result and respresents a blend of two fundamentals forecasts.

[21] SOO Green Comments on Illinois Power Agency Policy Study, see page 10.

[22] Energy Storage Associations Comments on Illinois Power Agency Policy Study, see pages 6-8. 20240226-energy-storage-associations-comments.pdf (Illinois.gov)

Figure 8: Annual Commodity Price Forecast Comparison



The modeling team acknowledges that utilizing the 2023 AEO Reference Case gas price forecast would represent an increase of about 80 cents/MMBtu over the 2030-2049 period. Such an increase would raise wholesale market energy prices, and therefore increase market revenues for the policy resources.

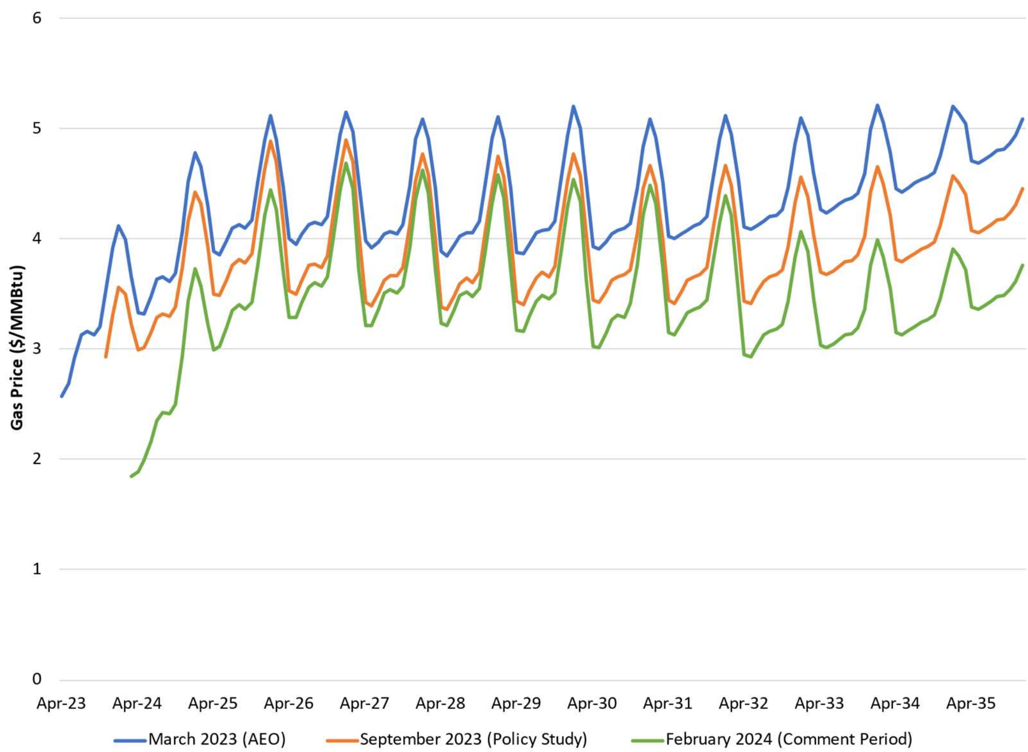
However, the 2023 AEO is dated by a year. It was released in March 2023, and no update will be released in 2024 due to EIA's National Energy Modeling System (NEMS) receiving "substantial updates to better model hydrogen, carbon capture, and other emerging technologies."[23] Since the AEO was published, the futures market curves for Henry Hub have decreased. While commenters claim that long-term NYMEX forwards for Henry Hub are not reactive to fundamentals, it appears that pricing has shifted substantially since the March 2023 AEO, and even since the modeling team set the gas price forecast last year. SOO Green's comments on the draft Policy Study indicated that their forecast, conducted by PA Consulting, includes two years of NYMEX forecasting, a fundamental forecast starting in four years and an interpolation of NYMEX and fundamentals forecasting in between.[24] The modeling team notes that NYMEX futures for Henry Hub have fallen from March 2023 when the AEO was released through the current comment period, which are almost a year apart, as shown in Figure 9. Presumably the step-down in near-term NYMEX futures would be a part of that forecast. While contracted volumes are significantly

[23] U.S. Energy Information Administration, Annual Energy Outlook 2023. Main webpage here:
Annual Energy Outlook 2023 - U.S. Energy Information Administration (EIA) Accessed February 20, 2024.

[24] SOO Green on Illinois Power Agency Policy Study, see page 8.

less in the outer years of the forecast, the difference is striking and suggests market expectations relative to the 2023 AEO have become more bearish.

Figure 9: Futures Price Comparison[25]



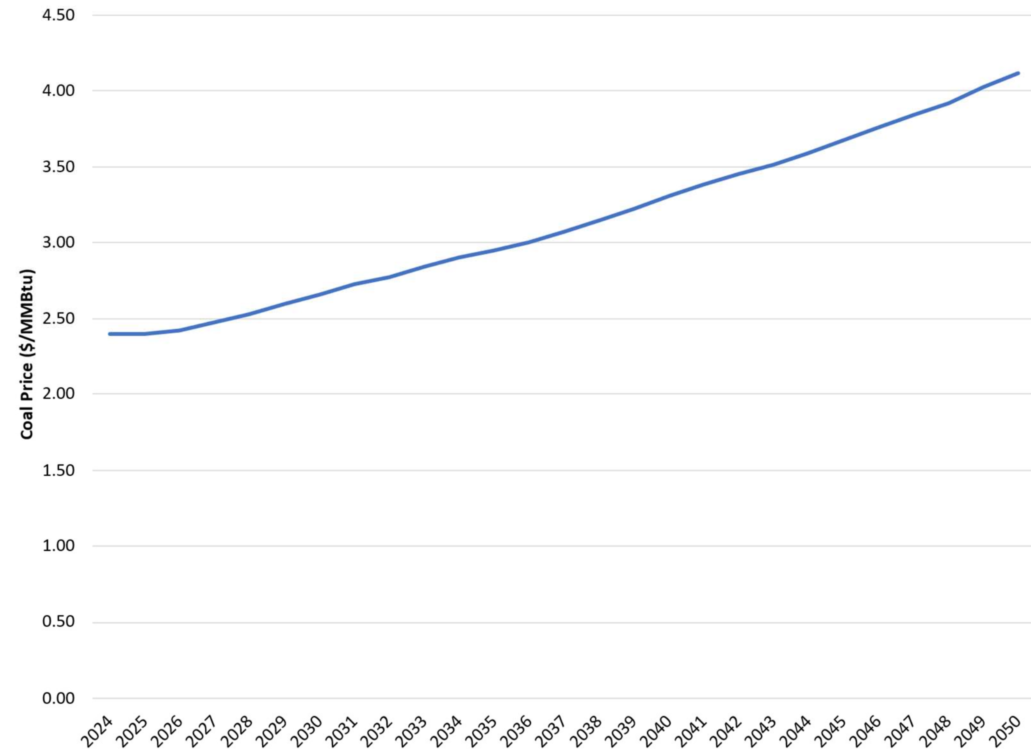
The decline in market expectations may well indicate underlying expectations for supply and demand that dictate a change in fundamental modeling in future editions of the AEO.

1.4.2 Other Fuel Price Forecasts

Coal prices were forecasted using the 2023 AEO prices for delivered coal to electric generators as a commodity price, adjusted for recent EIA Short-Term Energy Outlook ("STEO") projections for near term. These prices are then adjusted on a unit and state level to reflect local price adders based on basin sourcing and transportation costs. These adders are developed by Energy Exemplar and are primarily based on a review of EIA-923 fuel receipts data. Coal prices are projected to decline somewhat in real terms, the long-term price increase reflects inflation.

[25] NYMEX Futures obtained via S&P Capital IQ.

Figure 10~~5~~: Base Delivered Coal Price Forecast



Delivered oil products prices are also forecasted based on the 2023 AEO, adjusted for recent STEO projections for near term.

1.4.3 Emissions Allowance Price Forecasts

The model utilized the emissions allowance price forecast prepared by NYISO for its System and Resource Outlook study.[26] This biennial study includes a 20-year capacity expansion and production cost model run and was heavily vetted by stakeholders. Allowance pricing for criteria pollutants (NO_x and SO_2) will have minimal impact on dispatch costs under this forecast. The overall effect on plant dispatch during the ozone season will be less than $1/MWh for most facilities. The U.S. EPA recently proposed updates to the Cross-State Air Pollution Rule ("CSAPR") Good Neighbor rule, which is expected to receive protracted legal challenges. These rules are more likely to impact fossil resources by incenting retirements or capital investment in emissions controls rather than significantly affecting allowance prices. These decisions are captured to the extent that utilities and merchant facilities have made retirement decisions in MISO and PJM.

[26] Economic Planning Process 2023-2042 System & Resource Outlook, presented by Sarah Carkner to the NYISO Electric System Planning Working Group on September 21, 2023. See slides 18-19.

https://www.nyiso.com/documents/20142/40143257/05a_09212023_ESPWG_2023-2042_Outlook_Update.pdf

1.5 Firm Resource Additions and Retirements

The model relied on Futures Siting data for Series 1A Future 1 that has been released to MISO stakeholders to identify resources for addition and retirement.[27]

Given the delays in the PJM's BRA schedule, conventional facilities identified as "under construction" in the S&P Capital IQ power plant database are included in the base model.

1.5.1 Scheduled Renewable and Clean Energy Resource Additions

The model relied on siting data from MISO Series 1A Future 1 to identify clean energy resource additions in MISO. The Futures cases include both "planned" resources, which are expected future build based on MISO member-submitted updates, and "model-built" resources, which are generic resources selected by MISO's capacity expansion model. Model-built capacity is mainly sited based on active queue positions that are not already assumed as planned capacity. Model-built capacity was not included for MISO LRZ 4 (Illinois), as these resources are expected to compete with the resources that would be built under the policy cases.

The forecast assumes that wind and solar with signed Interconnection Service Agreements ("ISAs") in PJM will be built. However, PJM reporting indicates that many solar projects within its interconnection queue complete all required studies and still face attrition. All queued projects that are not yet designated "under construction" but have an ISA in hand received a 50% derate.[28] Offshore wind procurement targets in New Jersey, Virginia, and Maryland are taken into account.

As vertically integrated utilities, Dominion Virginia Power and Appalachian Power will have more options (long-term contracting, owning facilities) to comply with state clean energy goals than other compliance entities in PJM.[29] 26 GW of incremental solar development, phased in gradually over the study period, reflected Alternative Plan B of Dominion Virginia's 2022 Update to the 2020 Integrated Resource Plan.[30] This Alternative Plan reflects Virginia Clean Economy Act (VCEA) goals, which declare 16,100 MW of solar and onshore wind to be in the public interest.[31] The VCEA also includes a commitment to build 5.2 GW of

[27] See October 2, 2023 meeting materials from the Long Range Transmission Planning workshop:

Long Range Transmission Planning (LRTP) Workshop (misoenergy.org)

[28] The 2022 State of the Market Report (2022 State of the Market Report for PJM (monitoringanalytics.com), see Table 12-24) lists historic completion rates of 47.1% for projects that receive an FSA, and 57.4% for projects that receive a CSA.

[29] There are other vertically-integrated utilities in PJM, but they face less stringent clean energy targets than in Virginia.

[30] https://cdn-dominionenergy-prd-001.azureedge.net/-/media/pdfs/global/company/2022-va-integrated-resource-plan.pdf See p. 19.

[31] LIS > Bill Tracking > HB1526 > 2020 session (virginia.gov)

offshore wind. Corporate ESG commitments related to Virginia's future demand for power also support the addition of renewables beyond the current legislative mandate.[32]

1.5.2 Firm (Scheduled) Retirements

The Base Case included retirements documented by the ISOs in planning documents and notices. MISO identified planned retirements in its LRTP stakeholder materials, and also provided default age-based retirement assumptions in its Futures Refresh assumptions book.[33] MISO also includes retirement of some fossil plants subject to the Climate and Equitable Jobs Act ("CEJA") through 2042~~.~~, but further adjustments were necessary to account for undercounting in the Futures study.[34] PJM deactivations lists are reflected in the resource mix. Remaining Electric Generating Units ("EGUs") in Illinois were identified for retirement in 2045 under CEJA.[35]

Provisions in the Inflation Reduction Act and DOE's Civil Nuclear Credit program, along with state support, reduce near-term economic pressures on the nuclear fleet. Absent news to the contrary, nuclear units in the study region were assumed to receive Subsequent License Renewals ("SLRs"), which generally bring them to 80 in-service years.[36] While the decision to make capital investments to extend facilities' operating lives is heavily site specific, firms with nuclear assets have typically taken actions to preserve their ability to receive SLRs. This assumption is consistent with MISO's Futures Refresh assumptions.[37]

Unit retirements due to other policy considerations in PJM at large were evaluated, as discussed in PJM's Energy Transition Special Report. The report estimates that as much as 24 GW of fossil capacity may retire as a result of federal, state, and corporate policies.[38]

1.6 Capacity Expansion Modeling

The capacity expansion forecast utilizes Aurora's Long Term Capacity Expansion functionality to determine an equilibrium path of annual resource additions and retirements beyond scheduled additions and retirements. Under this functionality, Aurora calculates the present value of all existing resources and determines which generators are candidates for retirement based on lowest present value over the

[32] A large portion of the demand increase in PJM is attributable to new data centers planned by Amazon Web Services. Given Amazon's corporate commitments for ESG, along with Virginia state goals, offsetting renewables to "green" this demand may be reasonable.

[33] 20230428 LRTP Workshop Item 03b Futures Refresh Assumptions Book628727.pdf (misoenergy.org), p. 3.

[34] In comments on the draft Policy Study ICJC pointed out that MISO's Future 1A does not account for all fossil retirements under CEJA, which is correct (See comment p. 5), but those retirements were accounted for in the draft study. Other sources were used to identify units and timing of CEJA retirements for MISO.

[35] CEJA defines EGUs as units with a generating capacity of 25 MW or greater. This Study utilized the 2023 Phase II report from the Energy Transition Workforce Commission to identify expected retirement dates, see Appendix 1.

etwc_phaseireport.pdf (illinois.gov)

[36] Several nuclear units in PJM have applied for or intend to apply for NRC SLR, such as Peach Bottom, Surry, and North Anna. Constellation has indicated plans to apply for SLR for the Dresden facility.

[37] 20230428 LRTP Workshop Item 03b Futures Refresh Assumptions Book628727.pdf (misoenergy.org), p. 3.

[38] energy-transition-in-pjm-resource-retirements-replacements-and-risks.ashx, p. 8.

forecast period. Expected capacity prices are a direct driver of new build decisions under the simulation logic.

The model iterates to an equilibrium solution given potential candidate new resource options and retirements. In each iteration an updated set of candidate new resource options and retirements is placed into the system and the model performs its chronological commitment and dispatch logic for those resources. The model tracks the economic performance of all new resource options and resources available for retirement based on market prices developed in the iteration. At the end of each iteration the long-term logic decides how to adjust the current set of new builds and retirements, or it determines that the model has converged on an optimal solution. This capacity expansion technique relies on each ISO's capacity demand in order to balance supply and demand and determine capacity prices.

Aurora was only used to conduct MISO capacity expansion modeling for the 2043-2050 period, which is not covered by the Futures study.

1.6.1 Capacity Demand Curve Forecast

A projection of the PJM demand curve, the Variable Resource Requirement ("VRR"), is implemented in the Aurora model to forecast PJM capacity prices. PJM's BRA planning parameters for the 2025/2026 Delivery Year serve as the foundation of the VRR forecast. Parameters were adjusted per the latest quadrennial review and future demand from the 2023 Load Forecast Report. Specifically, an adjustment to the points on the VRR curve will be made for the RTO and each forecast LDA (MAAC, EMAAC) based on a ratio of the forecasted peak demand, net BTM solar, to the reported BRA peak for the 2025/2026 Delivery Year. LDA-level requirements were determined using data available on Capacity Emergency Transfer Limits ("CETL") and Capacity Emergency Transfer Objectives ("CETO") in the area.

MISO does not have an administratively set demand curve for capacity; resources clear at the offer price at the specified reserve margin. No Aurora capacity price was forecasted for MISO, as the Future 1A capacity expansion for the region does not include an implied capacity price. Given the large reliance on self-supply in MISO, the Planning Reserve Auction is more of a residual market. As noted in section 2.2.2~~2.1.3~~, MISO capacity prices were estimated outside of Aurora. Over time PJM and MISO capacity markets are expected to tighten due to coal retirements and age-based attrition.

1.7 Addition/Attrition Forecasting

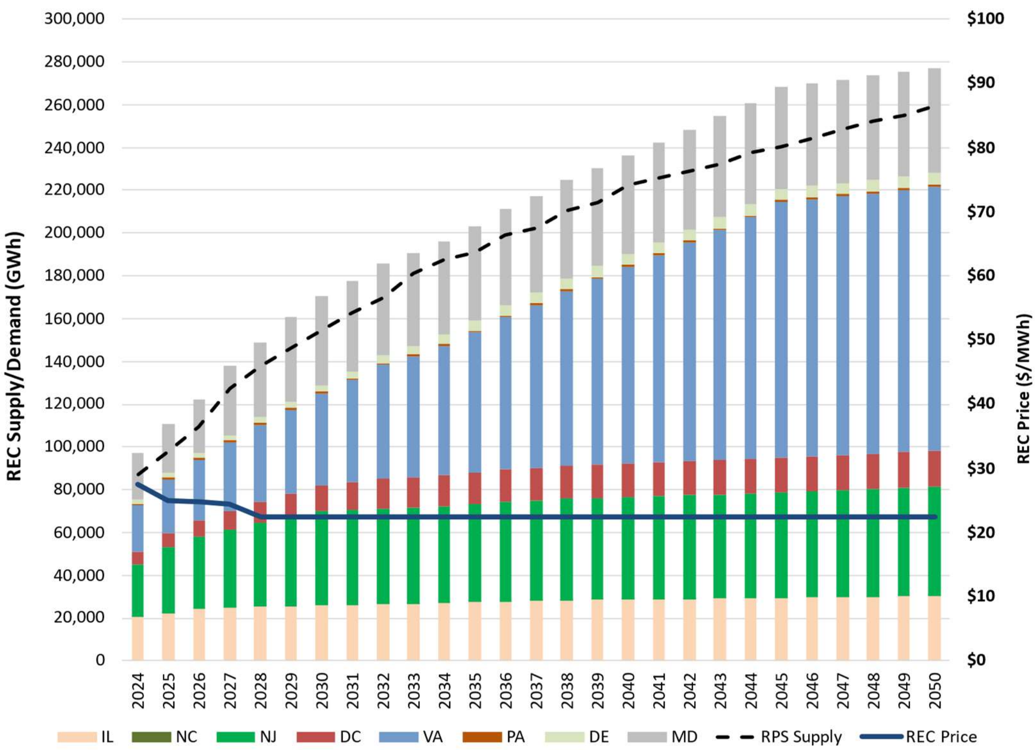
1.7.1 Candidate Additions

Model inputs include candidate resources which Aurora considers for new additions. Cost of New Entry ("CONE") study CC and CT units, along with battery storage, were modeled as candidate resources in both MISO and PJM. Siting in MISO was informed by incremental new resources sited in MISO Future 2. Siting in PJM was determined based on review of the interconnection queue, IRPs, and state policies. No new fossil capacity was allowed to be built by Aurora in Illinois.

Renewable resources were included as candidate resources in PJM, but renewables were not forced to be built to meet states' Renewable Portfolio Standards. An Argus report notes recent REC market pressures due to the significant backlog in PJM's interconnection queue and tariff issues with solar products coming from Asia. The report also notes that several states are looking to increase their RPS requirements and exclude some existing resources such as municipal solid waste generators from Tier 1.[39]

Initial projections prior to detailed modeling indicate a long-term REC shortfall across the PJM region. Current REC pricing is consistent with the projected starting point at the Maryland Alternative Compliance Payment ("ACP"). The ACP represents a price that load serving entities may elect to pay back to the state for shortfall quantities rather than securing RECs to meet their compliance obligations. Given that Maryland's long-run ACP is set at $22.50/MWh (nominal), merchant generators may struggle to sell RECs without a long-term contract providing revenue certainty. Given these challenges and recent inflationary pressures, renewable projects are not expected to enter the market without long-term contracts. Under the balance shown below, Illinois and other PJM states would meet their compliance obligations while Maryland would likely see ACPs used for compliance so that costs are minimized.

Figure 11~~6~~: REC Balance and ACP Projection



The carbon emissions intensity for MISO in the 2043-2050 time period did not significantly increase since thermal generators and batteries were only added for resource adequacy.

[39] Viewpoint: PJM clean energy goals up for review | Argus Media

1.7.2 Candidate Retirements

Candidates for retirement are restricted to fossil generation which does not serve a cogen purpose. Smaller units (on the order of less than 20 MW) will be excluded from the candidate pool to reduce the solve iterations needed.

1.8 Policy Proposal Modeling Approach

The IPA's data requests to prospective developers and the legislation in the respective Senate and House bills were reviewed to determine the appropriate inputs for each policy proposal. To the extent information was not available from these sources, the modeling team relied on public sources of information to determine the appropriate inputs for the Aurora model. A 20-year contract life was assumed for the Offshore Wind and storage projects in order to levelize costs and benefits consistently across the 2030-2049 study period. While SB1587 and PA 103-0580 discuss contracts of "at least 15 year duration" for battery storage, applying a shorter contract life for battery storage would not have captured energy and capacity price increases, which are expected to be more favorable over the last five years of the study period. In comments on the draft Policy Study, Vistra supported the use of a 20-year contract, citing more favorable financial terms.[40] The SOO Green strike price is a levelized nominal value for a 25-year contract. Where the contracts are compared, the benefits and costs over the 2030-2049 study period are tabulated.

1.8.1 Offshore Wind Project in Lake Michigan

The modeling team assumed that the offshore wind ("OSW") project will be constructed with a 2030 in-service date, consistent with legislation. This assumption is aggressive relative to the expected development timelines but preserves a 20-year life of the project within the study period. Hourly output profiles were generated using the NREL's Wind Toolkit ("WTK") database, which includes wind resource data for the Great Lakes. WTK data for the 2011 weather year was utilized to preserve coincidence with the existing model database of renewable output profiles.

NREL's 5.5-MW reference land-based wind turbine from the NREL Annual Technology Baseline ("ATB") was utilized as the power curve input, consistent with the Current Cost Scenario in NREL's Great Lakes Wind Energy Challenges and Opportunities Assessment.[41] The Current Cost Scenario assumes that under the current technology, infrastructure and supply chain limitations, onshore wind turbines will be utilized in the Great Lakes. The OSW project was modeled with a nameplate capacity of 200 MW and with adjustments for losses (electrical, wake, availability, etc.) given this nameplate capacity to match the energy target in the legislation.

For the 200 MW OSW fixed-bottom projects, CapEx and OpEx data from the March 2023 Great Lakes Wind Energy Challenges and Opportunities Assessment from NREL was utilized.[42] The CapEx values had to be recalibrated to reflect the current technology scenario, rather than the advanced research technology

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[40] Vistra Corp.'s Comments on Illinois Power Agency's Draft 2024 Policy Study, see page 13.

20240213-vistra-corp.pdf (illinois.gov)

[41] https://www.nrel.gov/docs/fy23osti/84605.pdf See table 6 on page 99.

[42] https://www.nrel.gov/docs/fy23osti/84605.pdf

scenario (which reports far lower CapEx values). The cost values in the ensuing tables & charts reflect a fixed-bottom project option.

An alternative option would be to consider a floating OSW project. The NREL 2023 Annual Technology Baseline (ATB)[43] reports the Class 8 Offshore Wind (which reports an average water depth of 159 meters, the shallowest and least expensive of the floating projects), with a CapEx 23% higher than the deepest available fixed project (Class 7 Offshore Wind). The reported OpEx for floating projects in the NREL Great Lakes report is 15% higher than for fixed bottom projects. According to the NYSERDA Great Lakes Wind Energy Feasibility Study (which considers installations of fixed-bottom foundations in Lake Erie, and floating OSW in Ontario), estimated CapEx values are higher for OSW on Lake Ontario (median value of $4,140/kW in 2030) compared to $4,050/kW for fixed-bottom OSW on Lake Erie.[44] The increased costs, coupled with the additional uncertainty of employing a floating OSW platform, led to the use of a fixed platform for this analysis. Overall, cost estimates optimistically reflect fixed platforms despite likely siting at or near the maximum depths where fixed platforms are feasible. There is substantial uncertainty regarding the future costs of floating wind technology; the largest floating project currently in service is 88 MW.[45]

The OSW project is assumed to capture the 30% Investment Tax Credit (ITC), which will reduce the costs of investment.[46] Diamond Offshore Wind noted that if land-based turbines are used, they may contribute to meeting the 10% ITC domestic content bonus, which would further reduce capital costs.[47] Additional manufacturing for the onshore wind supply chain is being located in the United States, such as nacelle manufacturing for large turbines.[48] However, the domestic content requirements will grow to 55 percent for offshore wind projects which begin construction after 2027.[49] Given the uncertainty around whether large portions of the offshore wind project will utilize domestic content, this bonus was not part of the cost assumption. Based on the currently indicated points of interconnection, the 10% ITC bonus for brownfield site development is not expected to be captured.

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[43] https://atb.nrel.gov/electricity/2023/data

[44] NYSERDA. New York State Great Lakes Wind Energy Feasibility Study: Cost Analysis. December 2022. Page 40. https://www.nyserda.ny.gov/All-Programs/Clean-Energy-Standard/Clean-Energy-Standard-Resources/Great-Lakes-Wind-Feasibility-Study

[45] Offshore Wind Market Report: 2023 Edition, U.S Department of Energy Office of Energy Efficiency and Renewable Energy. Page 54. Offshore Wind Market Report: 2023 Edition (energy.gov)

[46] In the draft Policy Study released on January 22, 2024, the ITC was inadvertently excluded from the modeling. This has been corrected for the final Policy Study.

[47] Diamond Offshore Wind Comments, see page 6.

20240213-diamond-offshore-wind.pdf (illinois.gov)

[48] Inflation Reduction Act Spurs Breakthrough in Domestic Wind Production, U.S. Department of Energy Office of Energy Efficiency & Renewable Energy, December 14, 2023.

https://www.energy.gov/eere/articles/inflation-reduction-act-spurs-breakthrough-domestic-wind-production

[49] See IRS Notice 2023-38, page 5. https://www.irs.gov/pub/irs-drop/n-23-38.pdf

1.8.2 SOO Green Renewables and HVDC Transmission

SOO Green's supplemental response to the IPA's questions estimated commercial operation of the HVDC facility would occur in 2030, and renewable projects in Iowa serving the line would enter service in early 2029. For simplicity of modeling and reporting, all components of this policy option were assumed in service at the beginning of 2030. Based on responses in the initial response memorandum, the HVDC transmission is represented as a 2,100 MW one-way link between the Alliant West area in MISO LRZ 3 and the ComEd zone in PJM.[50] The line will have losses of about 3.1%; effectively about 2,035 MW will be received at maximum flow across the line.

SOO Green provided an optimized generation portfolio made up of wind, solar, and battery storage. Renewable generation profiles from the portfolio analysis were utilized, and storage dispatch reflected charging constraints on battery storage consistent with assumed restrictions. Battery storage is restricted to only charge when overgeneration from the supply portfolio is available, and to only discharge when transmission headroom is available.

A constraint ensures a minimum flow on the HVDC line at the hourly output of the green supply portfolio (up to the maximum capacity of the line). This constraint reflects the incentive to deliver renewable energy across the transmission line in order to receive Indexed REC revenues. Additional deliveries can be made into ComEd if the economics are warranted but are not counted as "clean." Incremental deliveries of system energy would not receive contract payments under an Indexed REC structure.

The SOO Green line bears many similarities to the Clean Path NY ("CPNY") transmission line, as demonstrated in the table below. CPNY was a selected project in NYISO's Tier 4 solicitation, which SOO Green has cited as an example of a potential approach for commercialization.[51] Rather than attempting to develop a ~~bottoms~~bottom-up estimate of the HVDC line cost and associated renewable energy, the CPNY strike price was adjusted to determine potential project costs.

[50] Though the line will have bi-directional capability, commercial obligations and grid limitations on the receiving end of the line will limit reversal of flow.

[51] Information on NYSERDA's Tier 4 solicitation, including public bid information and contracts, is on NYSERDA's web site: Solicitation and Award - NYSERDA

Table 3~~1~~: SOO Green & Clean Path NY Transmission Line Comparison

Clear Path & Soo Green Comparison

Items	Units	CPNY	Soo Green
CPNY Strike Price	$/MWh	129.75	115.08
HVDC Rating	MW	1,300	2,100
~~Transmission Line Length~~	~~Miles~~	~~178~~	~~350~~
How much of the lines are underground?	Miles	178	350
Building topology		Both primarily underground	
Design/operating life	Years	40	40
Expected life	Years	70	60
Line Utilization Factor	%	69.0%	69.4%

Items	Units	CPNY	Soo Green
CPNY Strike Price	$/MWh	129.75	115.39
HVDC Rating	MW	1,300	2,100
Transmission Line Length	Miles	178	350
How much of the lines are underground?	Miles	178	350
Building topology		Both primarily underground	
Design/operating life	Years	40	40
Expected life	Years	70	60
Line Utilization Factor	%	69.0%	69.4%

The reported strike price for the CPNY project is $129.75/MWh. Both CPNY, and the Champlain Hudson Power Express ("CHPE"), which was also selected in the Tier 4 procurement, petitioned for strike price adjustments via an inflation adjustment.[52] Given the run-up in inflation that occurred since the projects were bid in 2021, the CPNY strike price was adjusted upward by about 15% to reflect cost escalation. The inflation adjustment relied on the same index source and utilizes the same formula that NYSERDA has adopted for future onshore renewables procurements.[53] Comparisons were made between the historical Levelized Cost of Energy ("LCOE") of renewable (wind and solar projects) in both MISO and NYISO, to assist in deriving a corresponding value for SOO Green based on the recalibrated 20-year contract price for CPNY.[54] The SOO Green price was further adjusted by taking into account the cost of bringing 4-hour MISO

[52] See New York Department of Public Service Case 15-E-0302. CHPE filed a petition on August 28, 2023 and CPNY filed on June 7, 2023. Both petitions were withdrawn, but nevertheless indicate that strike prices are unlikely to support current costs.

[53] See Update to Renewable Energy Standard Purchase of New York Tier 1 Eligible Renewable Energy Certificates Request for Proposals (RFP) No. RESRFP22-1 RFP, released by NYSERDA on January 13, 2023. See page 53.

servlet.FileDownload (ny.gov)

Both Tier 4 projects cited this adjustment formula in their petitions.

[54] US DOE. Land-Based Wind Market Report. 2023 Edition. August 2023. Weblink: https://www.energy.gov/eere/wind/articles/land-based-wind-market-report-2023-edition. Lawrence Berkeley

battery capacity online for renewable supply balancing in 2030 (using similar cost assumptions for the MISO battery projects described above).[55] The strike price estimate did not account for changes in the cost of debt financing, given potential differences in the debt-equity structure and other considerations between SOO Green and CPNY. Interest rates have increased substantially since the Tier 4 projects' price submissions were made.

Given the large size and concentrated investment into a single contract, Illinois utilities may begin collections for the SOO Green project in advance of delivery of clean energy across the line. The magnitude, timing, and financial treatment of advance collections is uncertain, so near-term rate effects from such treatment were not quantified.

1.8.3 Energy Storage Systems Development

In October 2023, the modeling team met with representatives of energy storage associations to discuss assumptions and sources for the energy storage systems development timeline, cost, and operating characteristics. For the energy storage systems development targets, storage resources were added to meet the following procurement targets:

1. 3,000 MW by 2026,
2. 5,000 MW by 2028, and
3. 7,500 MW by 2030.

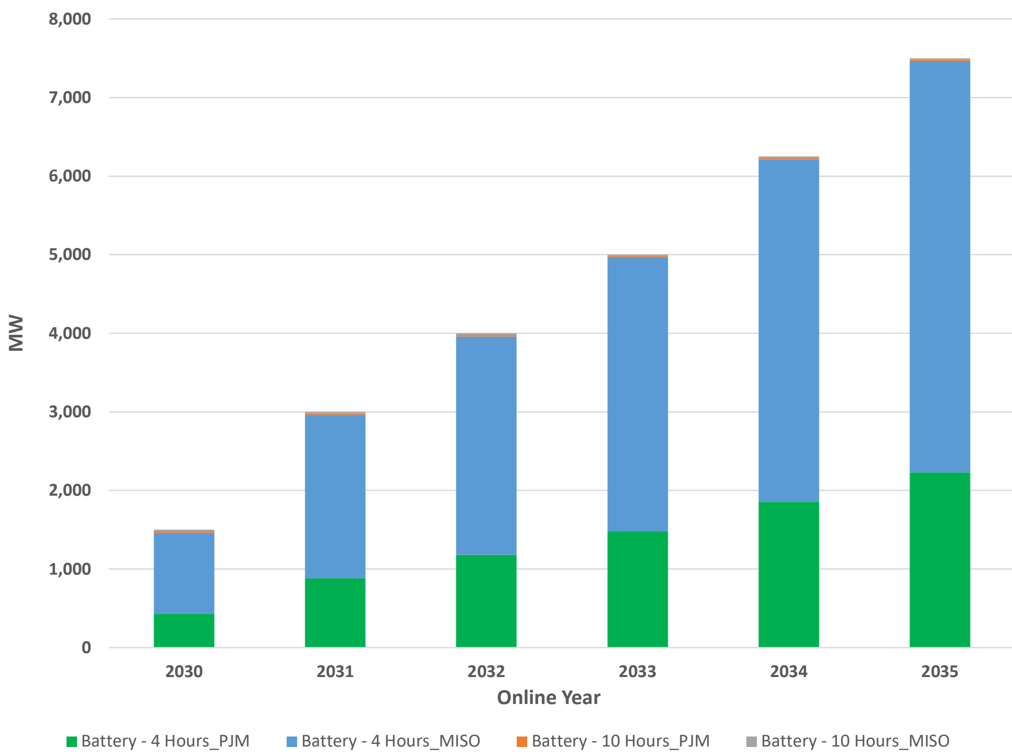
Accounting for development time and delays in implementing the legislation, deployment assumed was:

1. 3,000 MW by 2031
2. 5,000 MW by 2033, and
3. 7,500 MW by 2035

National Laboratory. Utility-Scale Solar, 2023 Edition. October2023. Weblink: https://emp.lbl.gov/publications/utility-scale-solar-2023-edition

[55] CPNY utilizes an existing pumped storage project for balancing, no incremental costs are associated with the change in pumped storage operations.

Figure ~~127~~: Deployment Schedule for Energy Storage Systems



Deployment targets were met at the beginning of the calendar year, rather than the delivery year, to simplify reporting processes. Development was phased in over intermediate years. SB 1587 prescribes that "[f]or all solicitations prior to the delivery year 2028, the Agency shall strive to procure at least 70% of energy storage credits from energy storage systems interconnected to MISO, and at least 10% of energy storage credits from energy storage systems located within a city with population of more than 1,000,000 people and interconnected to PJM Interconnection, LLC." From a zonal modeling perspective, those requirements translate to at least 70% in LRZ 4 and 10% in ComEd, with 20% unspecified. The additional 20% was sited in ComEd.

The duration of energy storage systems was assumed to be 4 hours, with the exception of two 20 MW, ten-hour units that will be developed under the long-duration/multi-day carveout in SB 1587.[56] Round-trip efficiency was assumed to be 85%, consistent with cost projections used in the NREL ATB.[57] Charging capacity is assumed to be identical to discharging capacity, and efficiency losses are "booked" as the

[56] SB 1587 gives the IPA discretion to adjust the duration requirements for solicitations in delivery year 2028 and later, but capacity accreditation factors for 4-hour resources in PJM and MISO are projected to be robust (75% or greater). Given that the main driver of cost for current energy storage systems is the storage capability, a 6-hour or 8-hour duration will not receive additional capacity revenue commensurate with costs.

[57] Cost Projections for Utility-Scale Battery Storage: 2023 Update, Cole and Karmakar, National Renewable Energy Laboratory issued June 2023. See page 8. https://www.nrel.gov/docs/fy23osti/85332.pdf

resource is charged.[58] Most battery storage resources reporting in Form 860 to the EIA have identical discharging and charging capacity, and interconnection studies typically model planned projects with the same grid withdrawal and injection amounts.

Operations were limited to reflect daily cycling limitations that may be part of long-term service agreements for maintenance. Under this constraint, discharge during a day was limited to the energy storage capability of the storage resource.

For the 4-hour and 10-hour MISO and PJM storage systems, CapEx and OpEx data from the NREL 2023 Annual Technology Baseline (ATB) database for utility scale battery storage was utilized.[59] The NREL ATB database provides CapEx and Fixed O&M estimates benchmarked with industry and historical data. The projects are planned to be built over several years – the costs per project decline by year. The conservative scenario (a 4-hour storage project built in 2030 has CapEx and FOM costs 29% and 19% lower respectively when compared to corresponding a 4-hour storage project built in 2023; future projects after 2030 observe an annual drop of 1.8% CapEx and 0.7% FOM) was selected.[60] The cost data is adjusted for location using data taken from the EIA Assumptions to the 2023 AEO: Electricity Market Module.[61]

1.8.4 Distributed Scale Paired Storage Sensitivity

Small-scale storage systems paired with distributed solar were considered as an additional policy option to consider incrementally with the 7,500 MW goal. ~~An additional~~ 1,000 MW of four-hour storage was modeled as in-service in 2030 to reflect additional storage realized by pairing with behind-the-meter solar.

Over the next two delivery years, the 2024 Long-Term Renewables Procurement Plan proposed 800 MW of program block capacity to be procured through Illinois Shines.[62] The block capacity for procurement was assumed to persist through the 2030 delivery year, which would incent about 5,600 MW of capacity to be procured to provide 8.3 million RECs. Of this quantity, about 20% is assumed to be small-scale solar, and the rest is assumed to be commercial scale solar.[63] Per NREL, battery nameplate for smaller residential scale systems is typically installed at a 5 kW battery to 8 kW PV and inverter size.[64] 200 MW of paired storage at smaller scale was assumed, which implies about a 30% adoption rate. Commercial

[58] For example, under these assumptions a four-hour battery with 80% round-trip efficiency takes five hours to charge.

[59] https://atb.nrel.gov/electricity/2023/data

[60] https://atb.nrel.gov/electricity/2023/utility-scale_battery_storage

[61] Published March 2023. https://www.eia.gov/outlooks/aeo/assumptions/

[62] 2024 Long-Term Plan, Illinois Power Agency, October 20, 2023. See Tables 7-1 and 7-2.

Microsoft Word - 2024 Long-Term Plan (20 Oct 2023 515pm).docx (illinois.gov)

[63] All of the Small Distributed Generation category, and one eighth of the Equity Eligible Contractor Category, is assume to be small scale solar. Large DG, community solar, and Public Schools were assumed to be commercial-scale systems.

[64] Ramasamy, Vignesh, Zuboy, Jarett, O'Shaughnessy, Eric, Feldman, David, Desai, Jal, Woodhouse, Michael, Basore, Paul, and Margolis, Robert. 2022. "U.S. Solar Photovoltaic System and Energy Storage Cost Benchmarks, With Minimum Sustainable Price Analysis: Q1 2022". United States. See Table 7. https://doi.org/10.2172/1891204. https://www.osti.gov/servlets/purl/1891204.

paired storage systems are more typically paired at a one to one ratio of battery to solar capacity.[65] The remaining 800 MW of paired storage was assumed at commercial scale, which implies about a 20% adoption rate. These adoption rates are optimistic relative to recent history, which suggests about a 10% attachment rate for residential and 5% for non-residential installations.[66]

Given that storage charging often occurs during hours with solar generation, charging was not restricted to a specific "paired" solar generator. Round trip efficiency was assumed to be identical to front-of-meter resources and cycling remained limited to once daily.

For the 4-hour MISO and PJM storage systems, CapEx and OpEx data from the NREL 2023 Annual Technology Baseline (ATB) database for residential (200 MW) and commercial (800 MW) battery storage was utilized.[67] The NREL ATB database provides CapEx and Fixed O&M estimates benchmarked with industry and historical data. The projects are planned to be built in 2030. The conservative scenario (both commercial and residential 4-hour storage projects built in 2030 have CapEx and FOM costs 19% and 19% lower respectively when compared to corresponding 4-hour storage projects built in 2023; future projects after 2030 observe an annual drop of 0.3% for both CapEx and FOM) was selected.[68] The cost data is adjusted for location using data taken from the EIA Assumptions to the 2023 AEO: Electricity Market Module.[69]

No cost synergies for paired storage were included in the cost modeling, but the Investment Tax Credit was applied to the cost values.

2 Production Cost Modeling Results

This section of the report provides a review of the Base Case results and compares the modeled benefits of the policy proposal cases to the potential costs.

2.1 Base Case Results

Simulation modeling showed that when the bulk of Illinois fossil plants retired due to CEJA in 2045, energy adequacy problems were created in the ComEd zone and LRZ4. The zones could not meet peak load with expected renewables and storage on hand, subject to transmission import limits. Given that storage is one of the policy options tested in but-for cases, the modeling team elected to "repower" about 8.5 GW of fossil capacity retired under CEJA to Zero Emissions Fuel (ZEF) units, the bulk of which is switched over in 2045. These units were assumed to have zero CO_2 emissions and maintain their emissions rates for other pollutants (assuming that these values are driven in part by air permit limits). ZEFs have a high fuel

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[65] *Id,* see table 9.

[66] Max Issokson, Distributed solar-plus-storage holds much promise, but where does it stand today? Published August 10, 2023 by Wood Mackenzie.

https://www.woodmac.com/news/opinion/distributed-solar-plus-storage-holds-potential/

[67] https://atb.nrel.gov/electricity/2023/data

[68] https://atb.nrel.gov/electricity/2023/commercial_battery_storage and https://atb.nrel.gov/electricity/2023/residential_battery_storage

[69] Published March 2023. https://www.eia.gov/outlooks/aeo/assumptions/

price (averaging about $45/MMBtu during the 2040-2050 period).[70] These resources are called on sparingly during the production cost modeling, which effectively represents a 50/50 peak condition, but would be critical to support Illinois during stressed system conditions. For production simulation modeling of long-term transitions to non-carbon emitting future generation mixes, in the outer years of the modeling horizon it is not unusual for the modeling to show generation shortfalls for limited periods of time (usually a few hours) during periods with high demand and sustained low renewable output, which limits storage ability to balance load and clean energy. Since the future peaking resources necessary to cover these shortfalls have not been determined, the modeling assumes that proxy peaking units that do not emit carbon will be used. In this instance ZEFs are dispatched (in only a handful of hours) to meet high demand when renewable output is low. This technique is consistent with modeling practices that system operators have adopted to consider a full transition away from fossil fuels. MISO utilized Flexible Attribute Unit, or "Flex" technology in their Futures report to manage energy shortfall issues that were identified during production cost modeling:

> These "Flex" units are proxy resources that refer to a non-exhaustive range of existing and nascent technologies, representing potential generation that is highly available, highly accredited, low- or non-carbon emitting, and long in duration. As a proxy, potential Flex resources could be, but are not limited to: reciprocating internal combustion engines (RICE units), long-duration battery (>4 hours), traditional peaking resources, combined-cycle with carbon capture and sequestration, nuclear SMRs, green hydrogen, enhanced geothermal systems, and other emerging technologies.[71]

Certain costs related to these systems, cited from the NREL ATB, are provided below for illustrative purposes.

[70] The fuel costs for zero emissions fuel units is based on hydrogen. The Hydrogen price was derived from NYSERDA's Climate Action Council Scoping Plan and the associated Integration Analysis. See data annex:

https://www.nyserda.ny.gov/-/media/Project/Nyserda/Files/Publications/Energy-Analysis/IA-Annex-1-Inputs-and-Assumptions-2022-revised.xlsx

[71] MISO Futures Report, Series 1A, published November 1, 2023. See pages 2-3. Series1A_Futures_Report630735.pdf (misoenergy.org)

Table 4: Cost Parameters for Potential ZEF Technologies

Technology	Overnight Capital Costs ($/kW)	Fixed O&M ($/kW-yr)	Fixed O&M ($/MW-day)	Variable O&M ($/MWh)	LCOE ($/MWh)	Maturity
NG Combined Cycle H-Class integrated retrofit 95%-CCS	1046	58	158	4.33	Not Reported	N
NG Combined Cycle (H-Frame) 97% CCS	2122	56	153	4.26	Not Reported	N
Nuclear - Small Modular Reactor	7483	119	325	3.13	88	N
Utility-Scale Battery Storage - 10Hr	3263	82	223	0.00	Not Reported	Y

Notably, most of these technologies are not considered mature and face significant uncertainty around siting and commercialization. While storage is an available technology, it may not be able to cover sustained lulls in renewable generation. In addition, CCS and Nuclear SMRs represent baseload technologies that would run at a high capacity factor and reduce energy prices if included. ZEFs have a limited impact on energy price formation and ensure that modeled energy market pricing is almost entirely set by commercially mature technologies with better-known costs and operational regimes.

In comments on the Policy Study, the Energy Storage Associations argued that the introduction of ZEFs "may be suppressing the projected overall value of energy storage in the Draft Study by as much as hundreds of millions of dollars a year."[72] Given that the capacity factor for ZEFs averages 0.11% from 2040-2044, and 0.56% from 2045-2049, and the dispatch costs of ZEFs are high per the fuel price assumptions noted above, the ZEFs as formulated are meant to affect energy market dispatch as little as possible. The potential reductions in the use of ZEFs attributable to the policy options are shown in ensuing sections.

The state of New York has similar mandates to eliminate emissions from the electric grid via the Climate Leadership and Community Protection Act as Illinois has under CEJA. The New York Independent System Operator (NYISO) has therefore faced similar challenges to MISO in its economic planning forecasts regarding reliability during the clean energy transition, and has adopted a similar modeling approach to MISO~~.~~ by including a category of "dispatchable emissions-free resources" in their modeling that are functionally equivalent to ZEFs used in the modeling for this study.[73] Ameren Missouri's 2023 IRP Preferred Plan includes "… 1,200 MW of as-yet-unspecified clean dispatchable generation in each of 2040 and 2043."[74] Pacificorp's 2023 IRP included in its preferred portfolio "non-emitting peaking" resources,

[72] Energy Storage Associations Comments to the IPA Draft Policy Study, page 10.

[73] "Substantial dispatchable emission-free resources (DEFR) will be required to fully replace fossil fueled generation, which currently serves as the primary balancing resource. Long-duration, dispatchable, and emission-free resources will be necessary to maintain reliability and meet the objectives of the CLCPA." 2021-2040 System & Resource Outlook (The Outlook), New York Independent System Operator, September 22, 2022. See pages 29-30.

a6ed272a-bc16-110b-c3f8-0e0910129ade (nyiso.com)

[74] 2023 Integrated Resource Plan, Ameren Missouri. See page 4.

https://s21.q4cdn.com/448935352/files/doc_downloads/2023/09/25/Chapter-1-Executive-Summary.pdf that "…are designed to run infrequently to support system reliability by dispatching only when needed to meet shortfalls."[75]

Idaho Power's 2023 IRP included hydrogen peaking units in the preferred portfolio, which was modeled in Aurora:

> While Idaho Power does not know which hydrogen technology may become commercially dominant, the company needed to select a technology profile to model within AURORA and, informed by available technology research, chose to model hydrogen as a SCCT with similar operating characteristics to natural gas units except for the fuel they burn and the emissions they produce.[76]

Energy and Environmental Economics utilized their PATHWAYS model to determine economy-wide decarbonization trajectories for Illinois. All PATHWAYS scenarios include hydrogen fuel cell build "… as clean firm resources to meet system need after gas generation is retired."[77] ISO-NE's Economic Planning for the Clean Energy Transition (EPCET) Pilot Study did not include full retirement of fossil generation in its base policy scenario, but has discussed [Synthetic Natural Gas] and Biodiesel sensitivities that would allow for repowering of existing units in a similar manner to ZEFs in order to further reduce fossil generation.[78] The Virginia Clean Economy act provides similar pressures on decarbonization as CEJA does for Illinois. Dominion Virginia Power avoided using a proxy technology in their Integrated Resource Plan, but it required that nuclear small modular reactors be built to retire existing fossil generation.[79] Likewise, the Eugene Water and Electric Board included SMR capacity in its 2023 IRP.[80]

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[75] ~~"Substantial dispatchable emission-free resources (DEFR) will be required to fully replace fossil fueled generation, which currently serves as the primary balancing resource. Long-duration, dispatchable, and emission-free resources will be necessary to maintain reliability and meet the objectives of the CLCPA." 2021-2040 System & Resource Outlook (The Outlook), New York Independent System Operator, September 22, 2022. See pages 29-30.~~

~~a6ed272a-bc16-110b-c3f8-0e0910129ade (nyiso.com)~~ 2023 Integrated Resource Plan Volume I, PacifiCorp, March 31, 2023. 2023_IRP_Volume_I.pdf (pacificorp.com)

[76] September 2023 Integrated Resource Plan, Idaho Power. See page 63.

2023 Integrated Resource Plan (idahopower.com)

[77] Illinois Decarbonization Study: Climate and Equitable Jobs Act and Net Zero by 2050, December 2022, see page 26.

[78] ISO-NE did not assume a binding zero carbon amount but rather a high carbon price. Economic Planning for the Clean Energy Transition (EPCET) Pilot Study: Additional Sensitivity Results, October 18, 2023 presentation to the NEPOOL Planning Advisory Committee, see slides 34-44.

a06_2023_10_18_pac_epcet_additional_sensitivity_analysis_results.pdf (iso-ne.com)

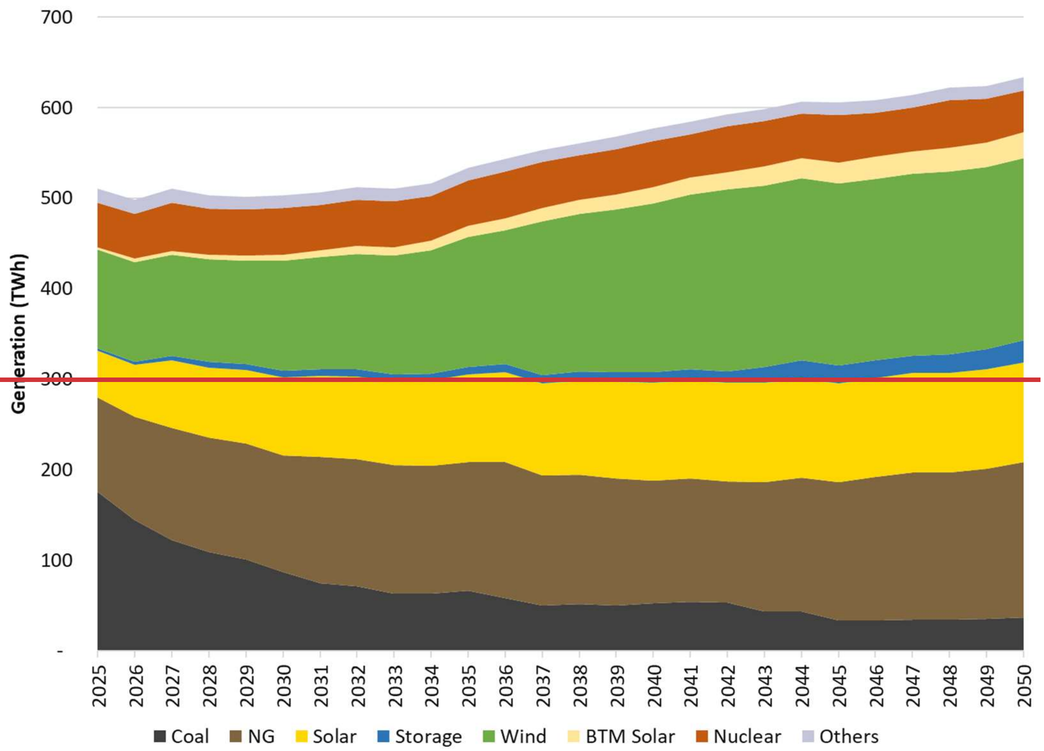
[79] Virginia Electric and Power Company's Report of Its 2023 Integrated Resource Plan, Filed May 1, 2023 in Virginia SCC Case No. PUR-2023-00066 Docket No. E-100, Sub 192, filed May 1, 2023. See pages 4-5.

2023 Virginia Integrated Resource Plan (azureedge.net)

[80] 2023 Integrated Resource Plan, Eugene Water and Electric Board, July 2023.

https://www.eweb.org/documents/energy-division/2022-IRP/2023-EWEB-IRP.pdf

Figure ~~13~~8 MISO Generation by Fuel Type



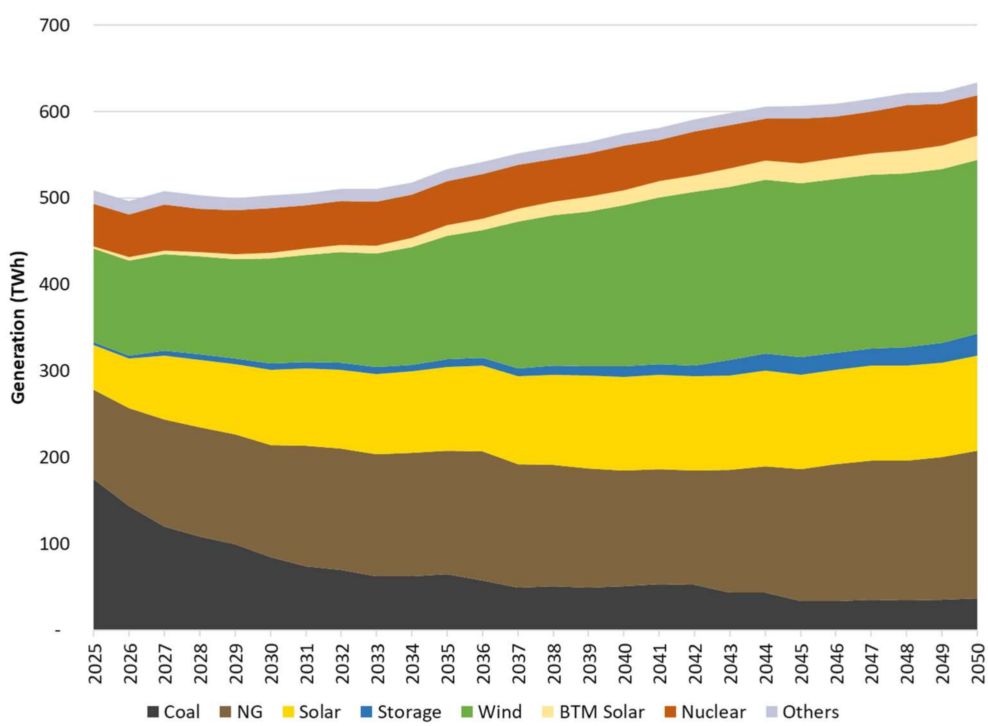
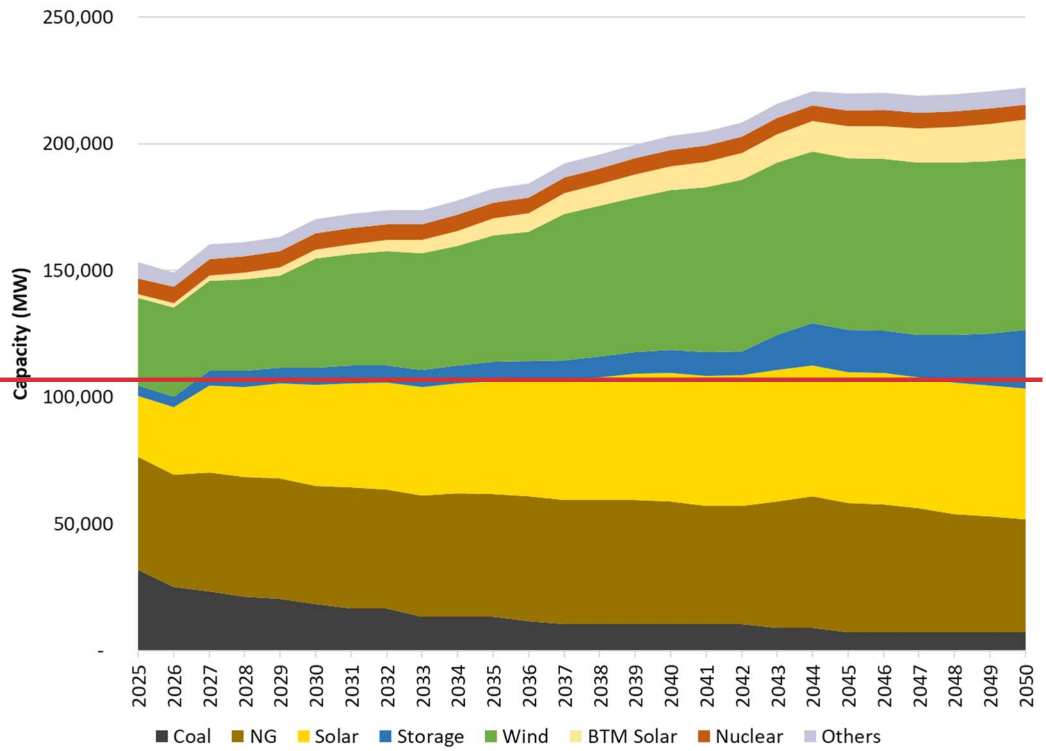
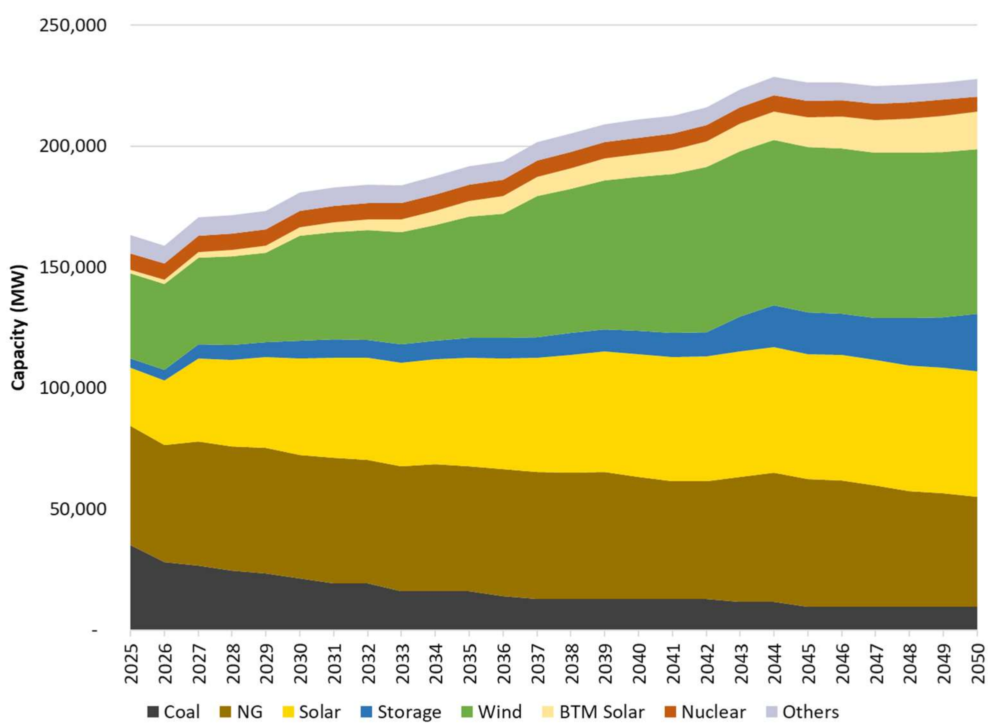


Figure 14~~9~~ MISO Capacity by Fuel Type

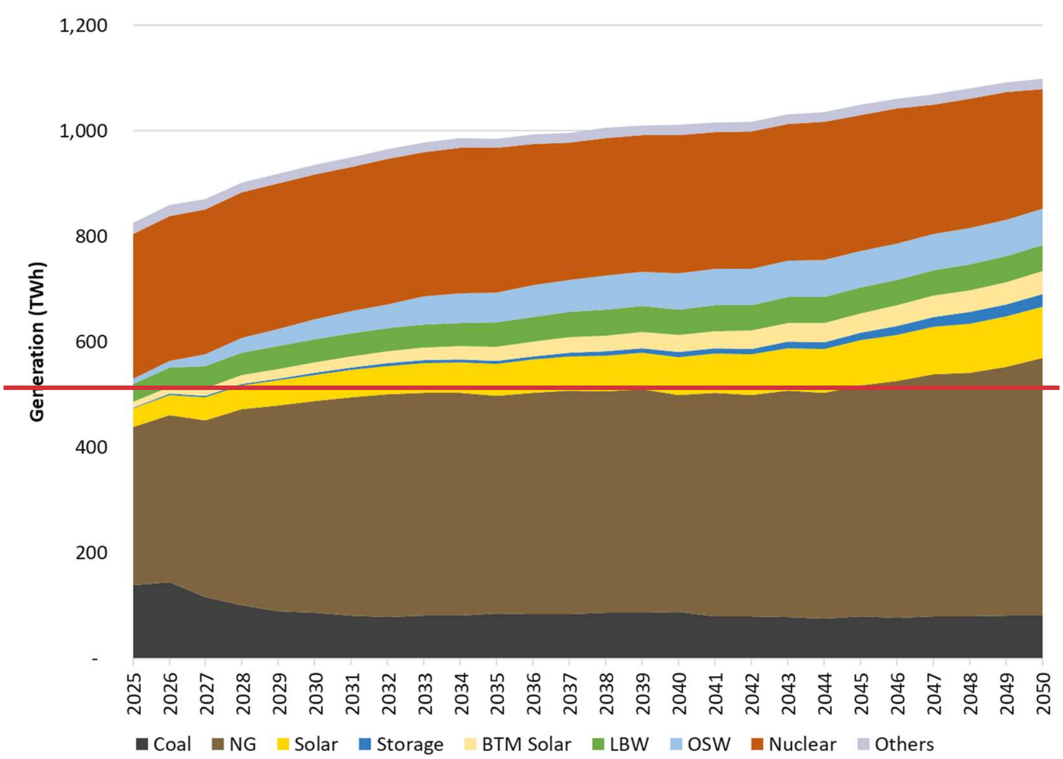




During the study period, there is a decline in the generation of fossil fuels, particularly coal, as mandated by utility planning, and the Illinois CEJA requirements. Concurrently, the generation from solar, wind, and storage increases to compensate for the diminishing capacity of fossil fuel units and to meet the growing energy demand in the region. Nuclear generation remains constant over the study period.

The introduction of ZEFs as an energy source in Illinois ~~occurs~~is phased in with some repowering occurring by 2040, and the majority after the complete retirement of all remaining fossil ~~units~~EGUs in Illinois in 2045. The "Others" category includes ZEFs, Oil, Hydro, Jet Fuel, Biomass, and Refuse.

Figure 15~~10~~ PJM Generation by Fuel Type



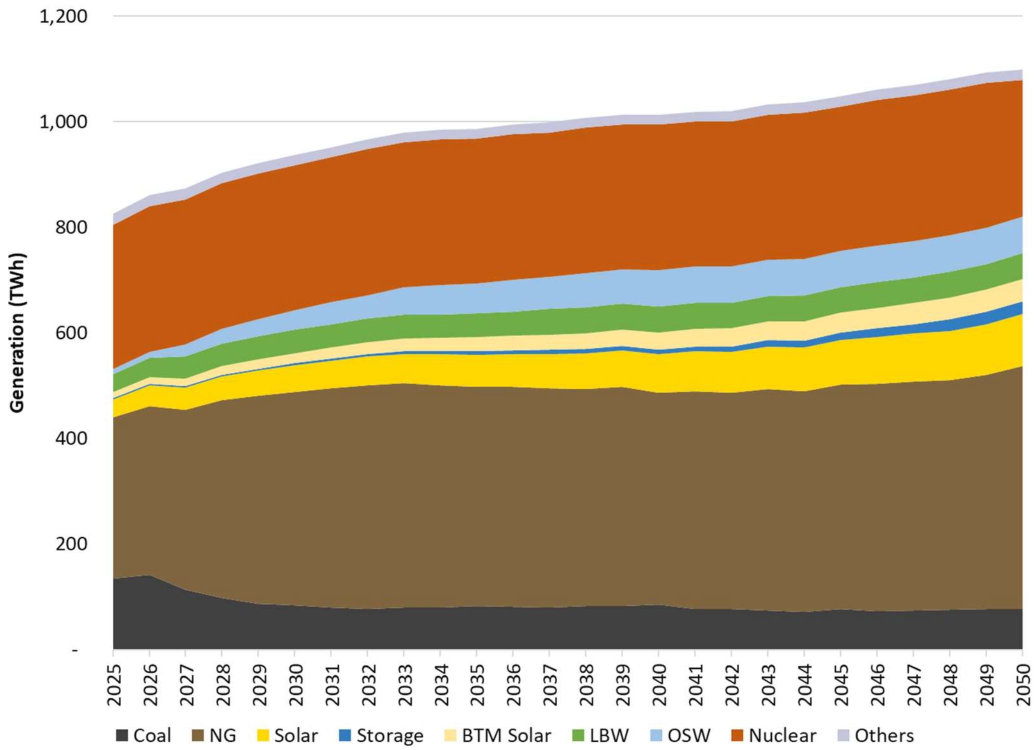
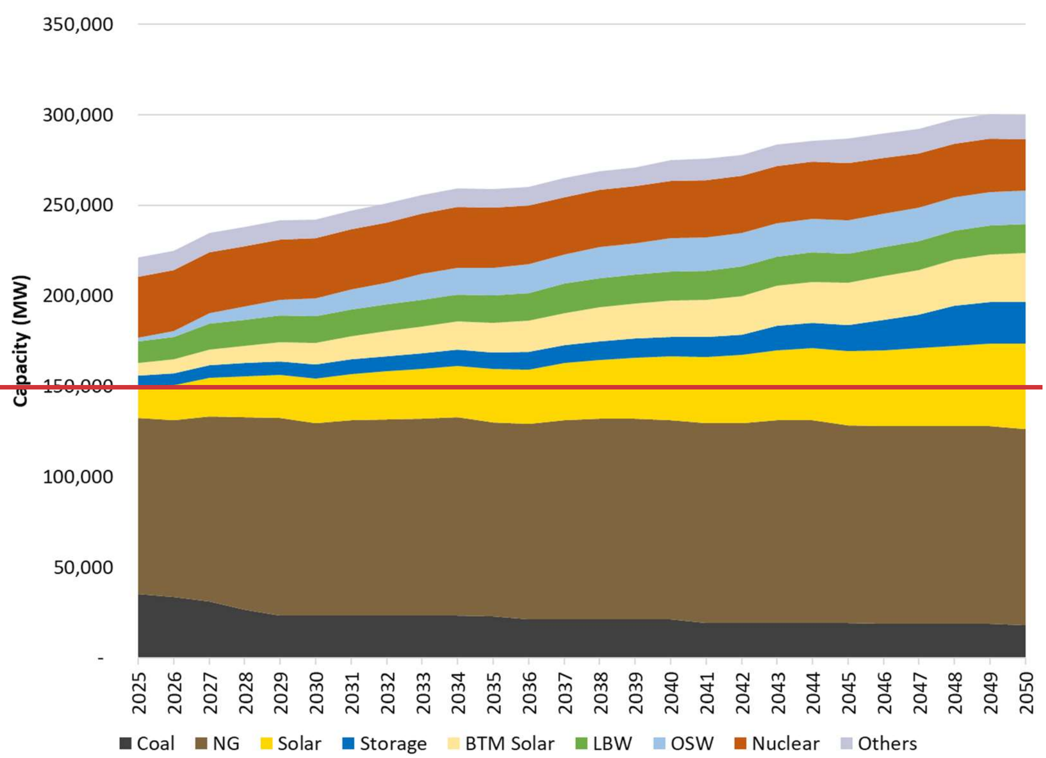


Figure <u>16</u>~~11~~ PJM Capacity by Fuel Type



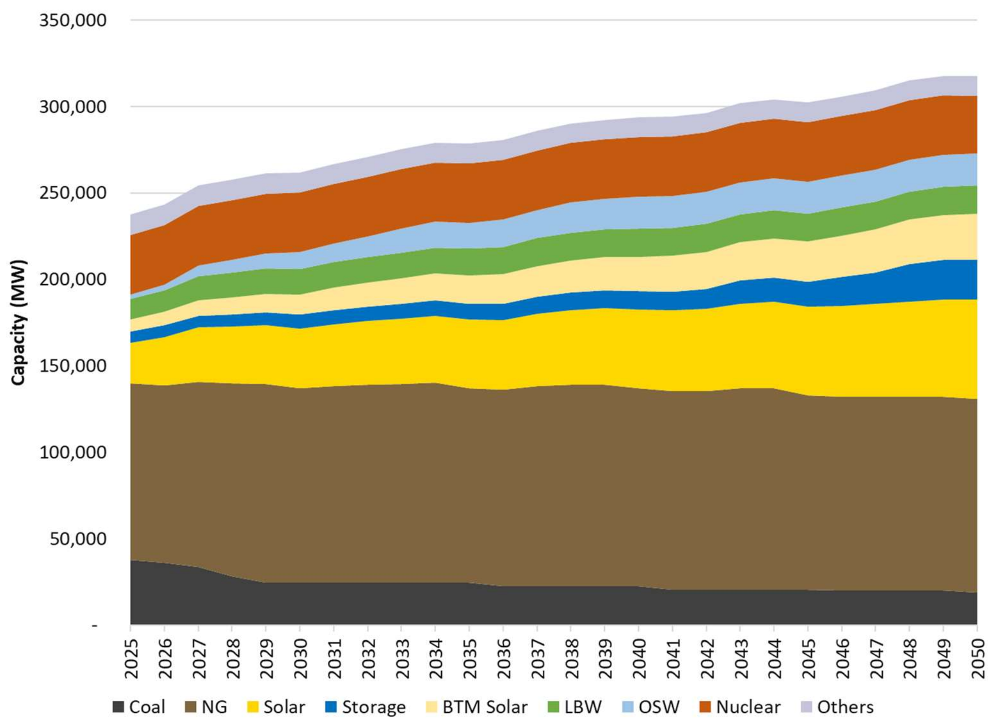


Figure 17~~12~~ **Illinois Capacity by Fuel Type**

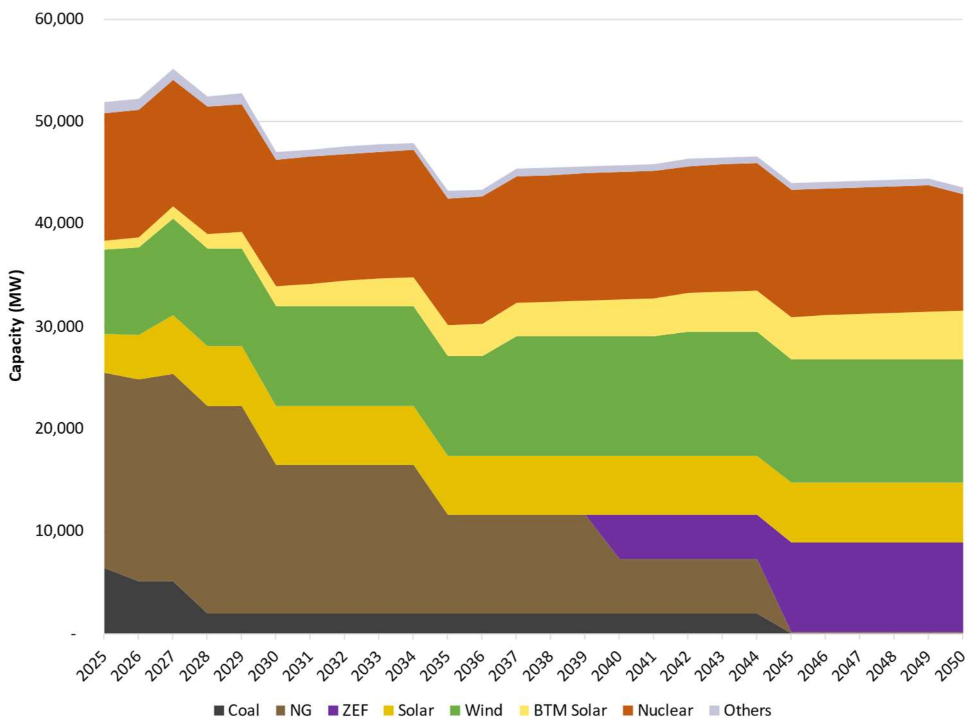
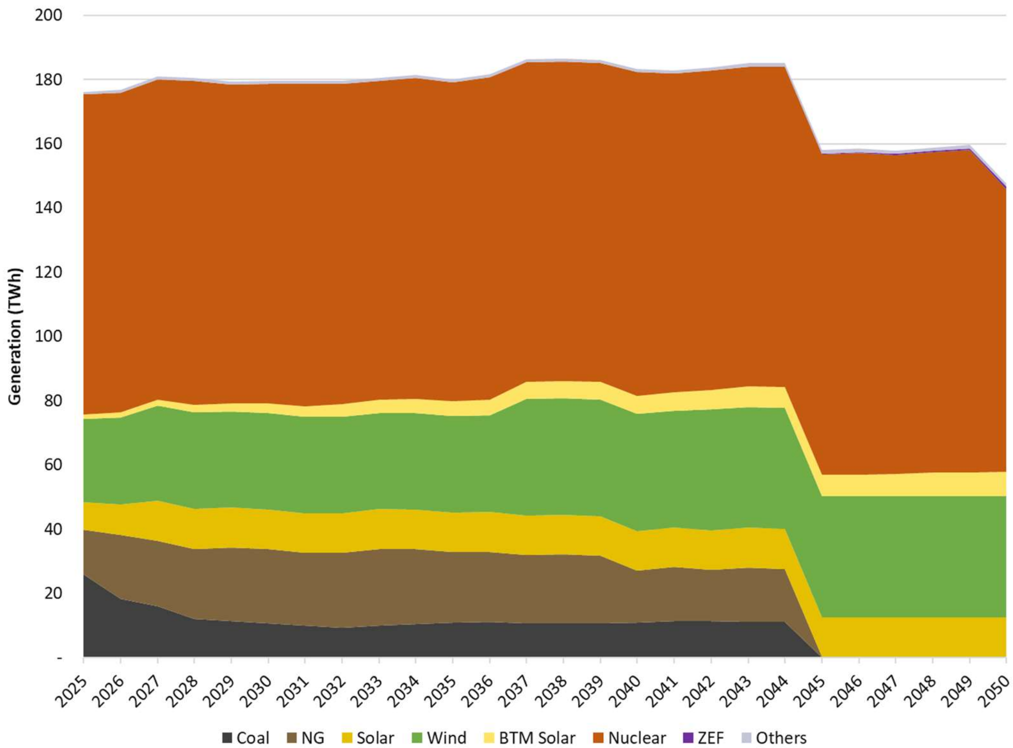


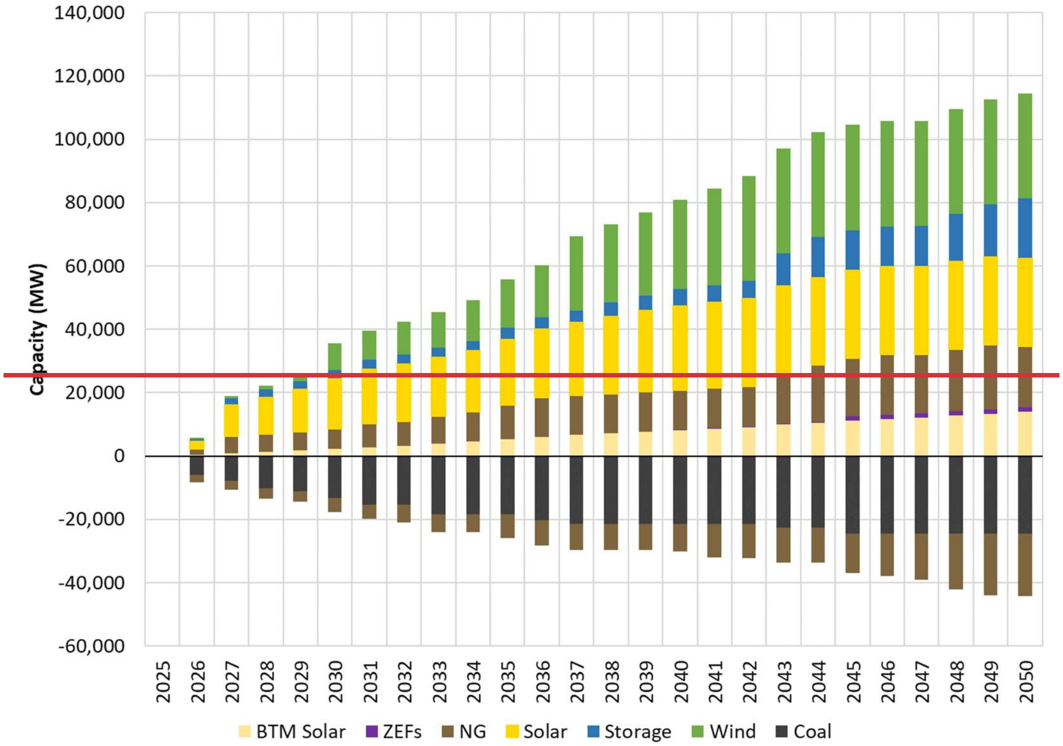
Figure 18 Illinois Generation by Fuel Type



The "Others" category includes Storage, Oil, Hydro, Jet Fuel, Biomass, and Refuse. Per the emission reduction mandates of CEJA, approximately 6.2 GW of gas and oil capacity would be retired by 2030. Another 4.9 GW of gas capacity would be retired by 2035, another 4.3 GW by 2040, and then the remaining 7.2 GW of fossil EGUs retired in 2045. Storage modeled as supply only accounts for 173 MW in the Base Case. An additional behind the meter storage generation value of 120 MW in 2038 is assumed in PJM's 2023 Load Forecast Report.[81] No specific storage forecast was extrapolated for future years, though reductions in peak demand are embedded in the load forecast values. 4.3 GW of ZEFs are added by 2040, though dispatch from 2040-2045 is limited. 8.8 GW of ZEFs are part of the resource mix from 2045 on.

[81] See materials from PJM's Load Analysis Subcommittee, November 29, 2022 presentation. https://www.pjm.com/-/media/committees-groups/subcommittees/las/2022/20221129/item-03d---state-zonal-breakdown---ihs-capacityatpeak-solar-battery.ashx

Figure 19 Cumulative MISO Resource Addition and Retirement



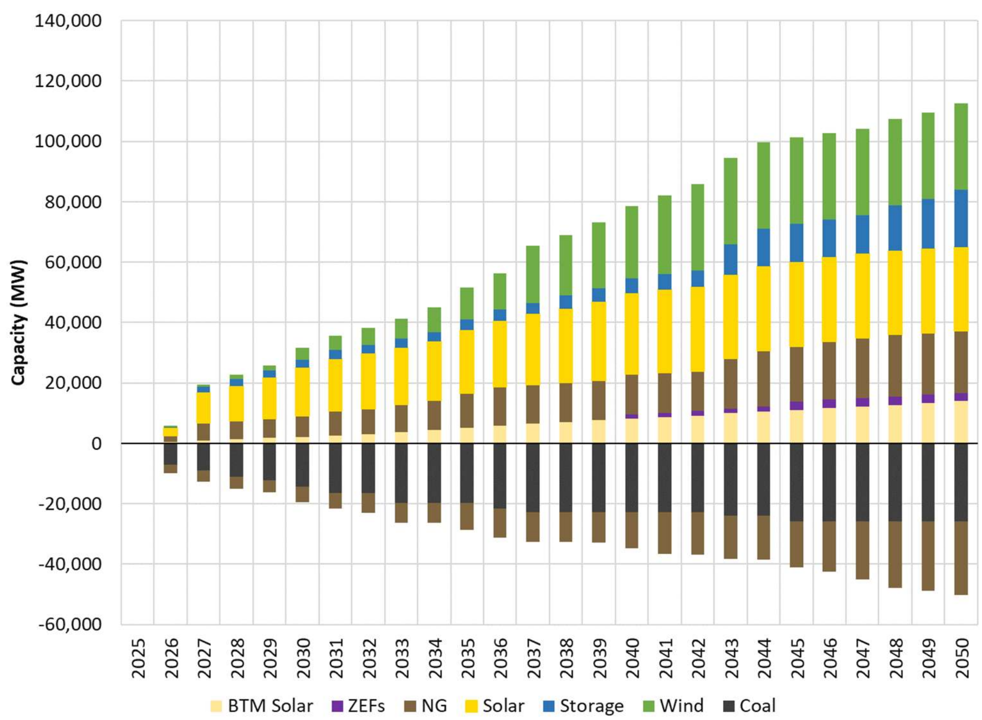
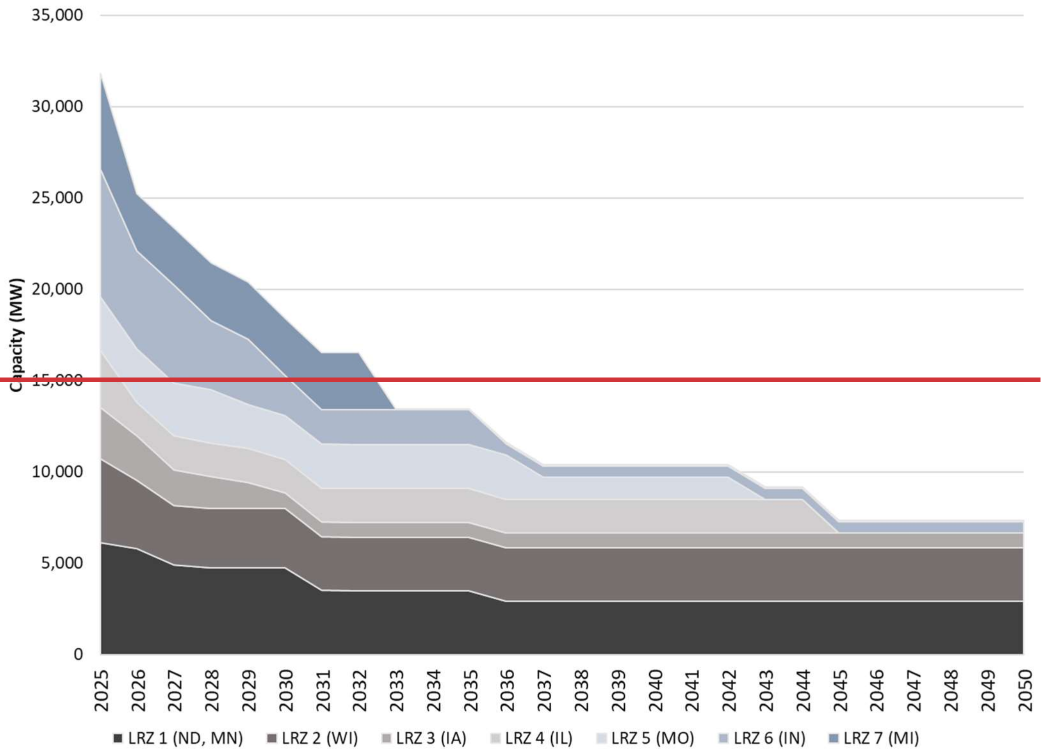
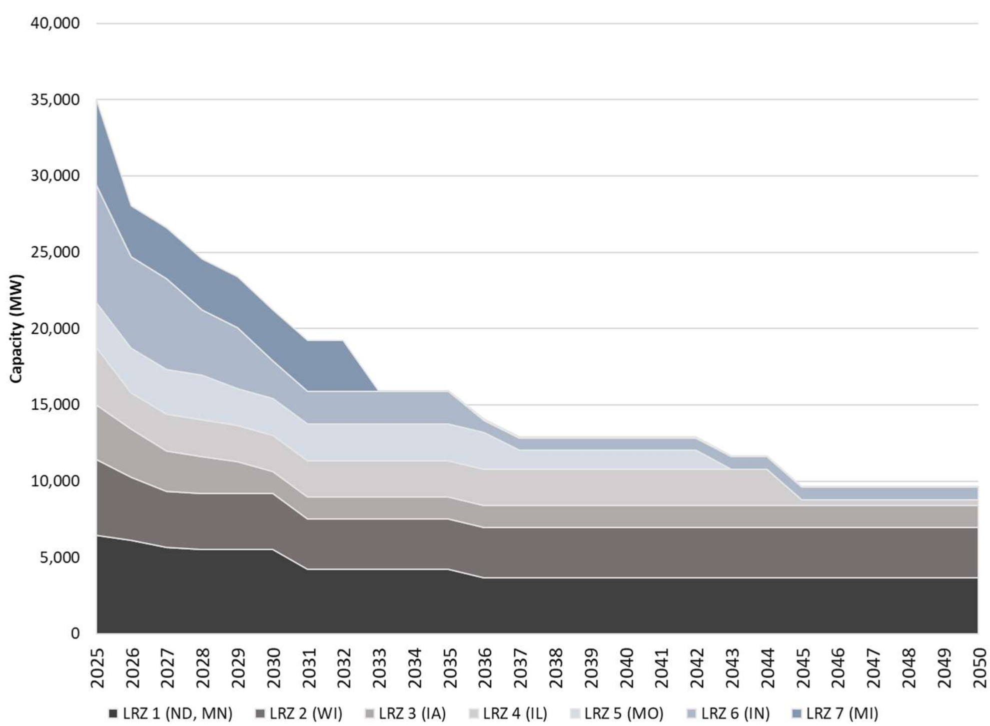


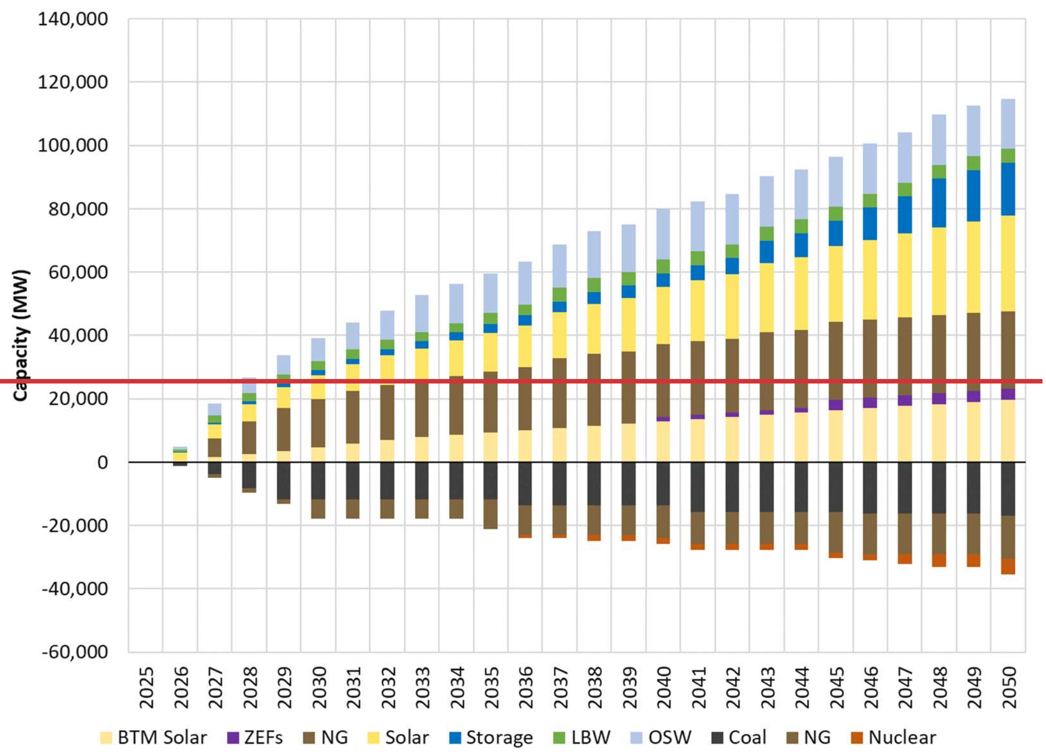
Figure 20~~13~~ Coal Capacity in MISO

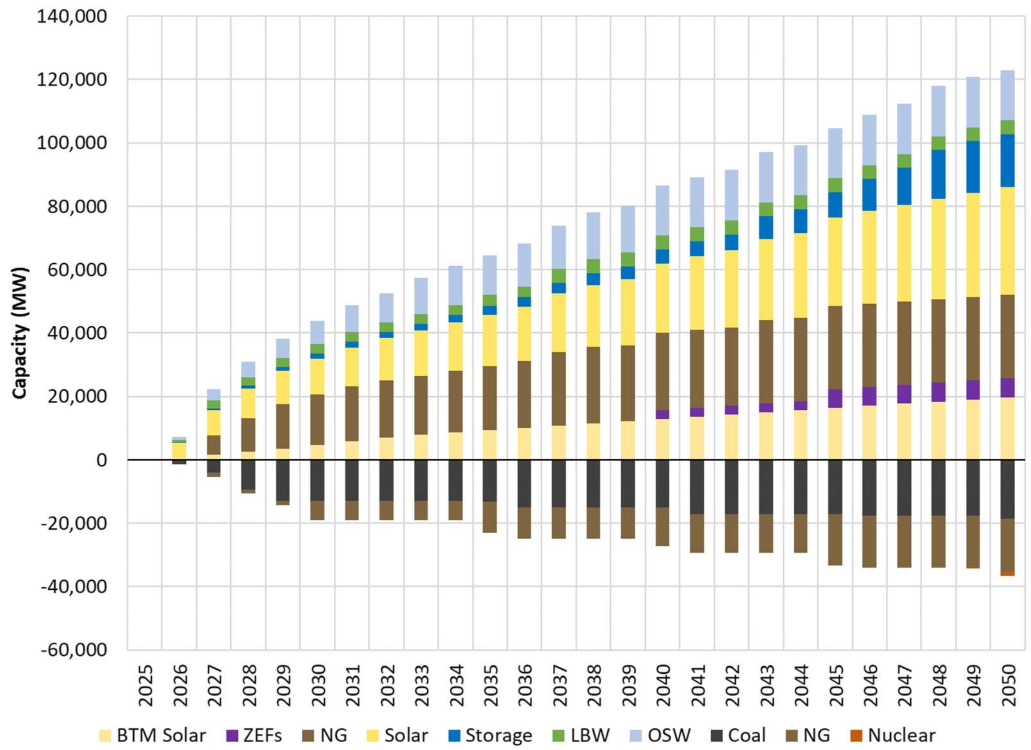




Renewable energy resources, such as solar, wind, storage, and behind-the-meter solar, make up a large portion of the additions to MISO's resource portfolio. Following the conclusion of the MISO Future Study period in 2042, the Long-Term ("LT") model selects storage and CONE units (CC and CT units) to maintain resource adequacy in the region. Toward the end of the study period, the retirement and addition of gas plants nearly balance out, although these dynamics vary significantly across different locations. During the studied period, all MISO LRZs phase out some portion of coal generation. MISO North (LRZs 1 and 2) deactivates a smaller portion of coal resources, while MISO Central (LRZs 3-7) deactivate the lion's share of their coal resources. Net storage capacity exhibits a positive trend across all zones save for LRZ 4 (Illinois), where storage expansion was not considered in order to properly test the storage policy implementation. Although older and less efficient gas units are replaced with planned and Futures model-built, and Aurora expansion gas units, zones 1, 3, 5, and 6 experience more additions of gas units, while in 2050, zones 2, 4, and 7 face more retirements than additions of gas units.

Figure 21~~14~~ Cumulative PJM Resource Addition and Retirement

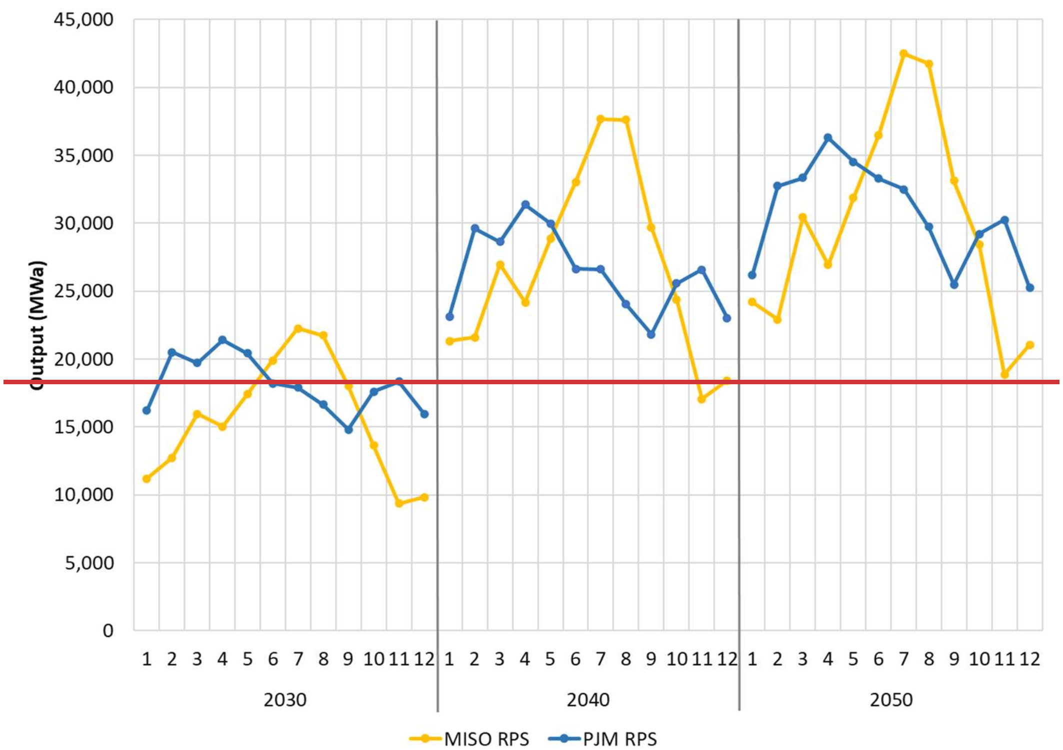




In the PJM region, there is a substantial surge in both behind-the-meter solar and utility-scale solar, amounting to a 50 GW increase by the year 2050. Additionally, there is a cumulative addition of 15.9 GW in offshore wind capacity by the same year.

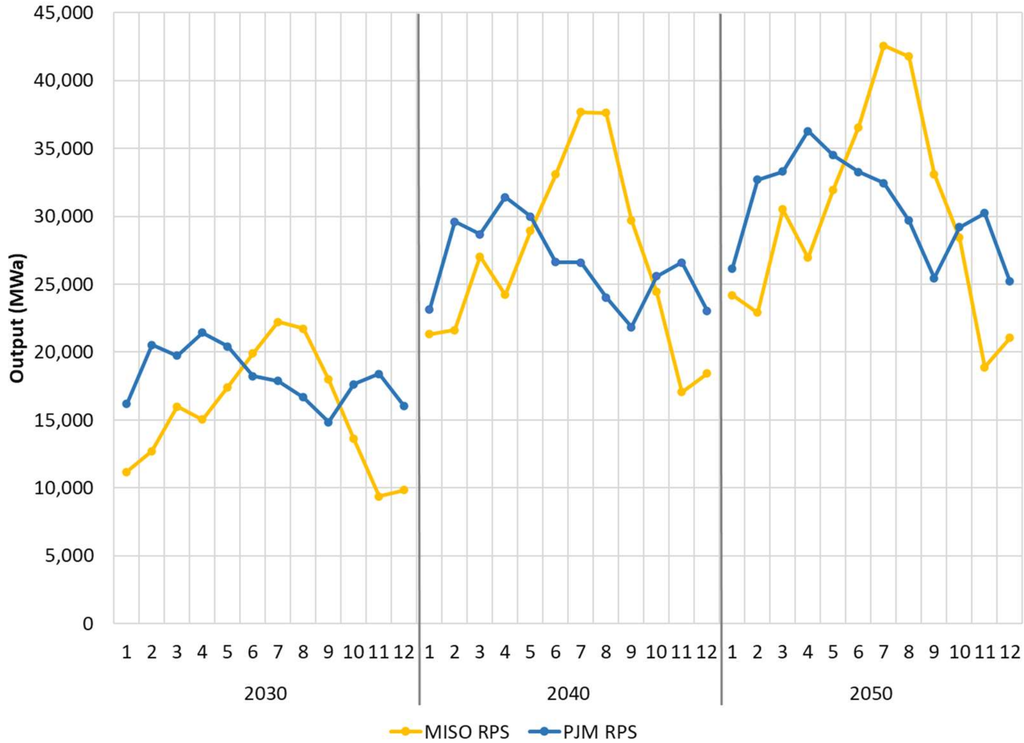
2.2 Renewables and Emissions

~~Figure 15 Monthly Average RPS Output by RTOs~~



The average RPS resource output in the studied regions of MISO and PJM exhibits a consistent upward trend over time. Throughout the months of June, July, August, and September, the average RPS output in MISO consistently surpasses that of PJM, with a margin ranging from 3.7 GW to 10.2 GW.

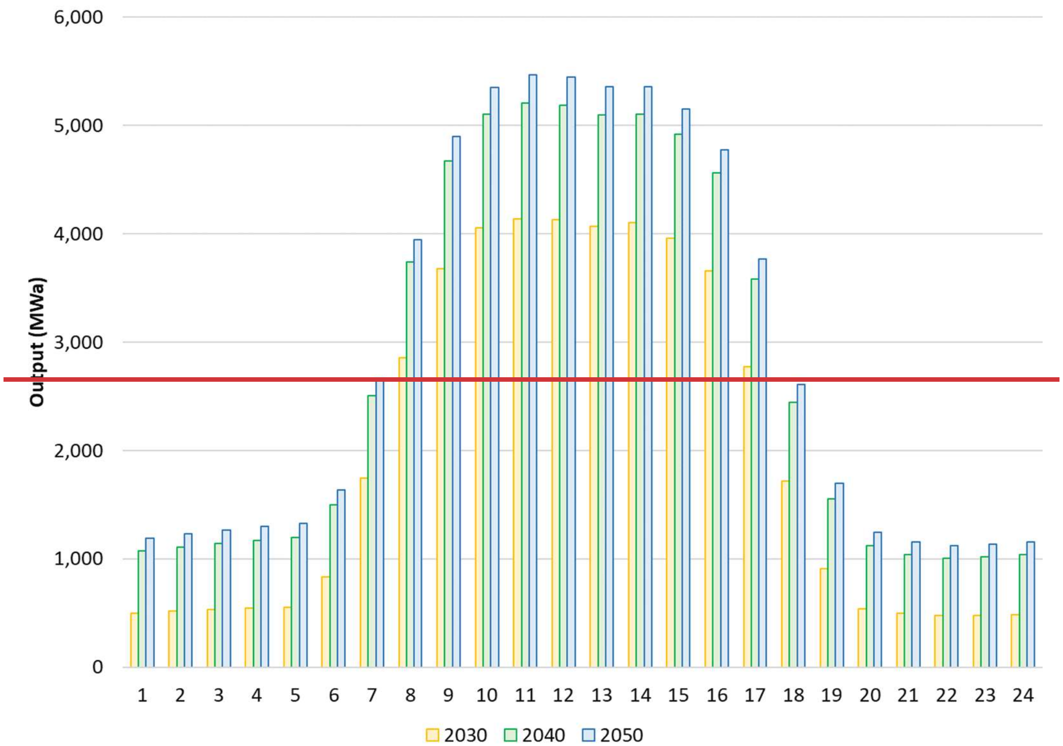
Figure 22 Monthly Average RPS Output by RTOs



MISO LRZ 4 consistently maintains an even hourly average RPS output throughout the entire study period. This pattern is primarily influenced by the addition of RPS resources, specifically solar, which exhibits its peak output in the middle of the day.

In the PJM ComEd zone, a dual peak system is consistently observed. This system is governed by RPS resources, with solar contributing to a peak in the middle of the day and wind reaching its peak later in the evening and overnight. The heightened magnitude of the midday peak indicates that the pace of solar additions is faster compared to other types of RPS resources.

Figure 23~~16~~ Hourly Average RPS Output MISO LRZ 4



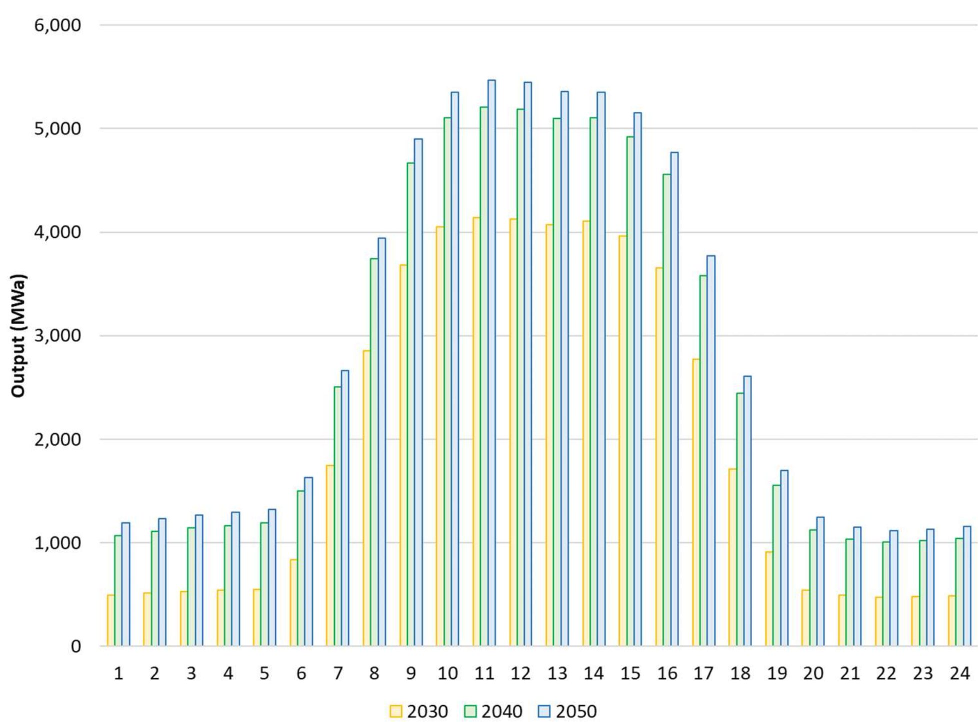
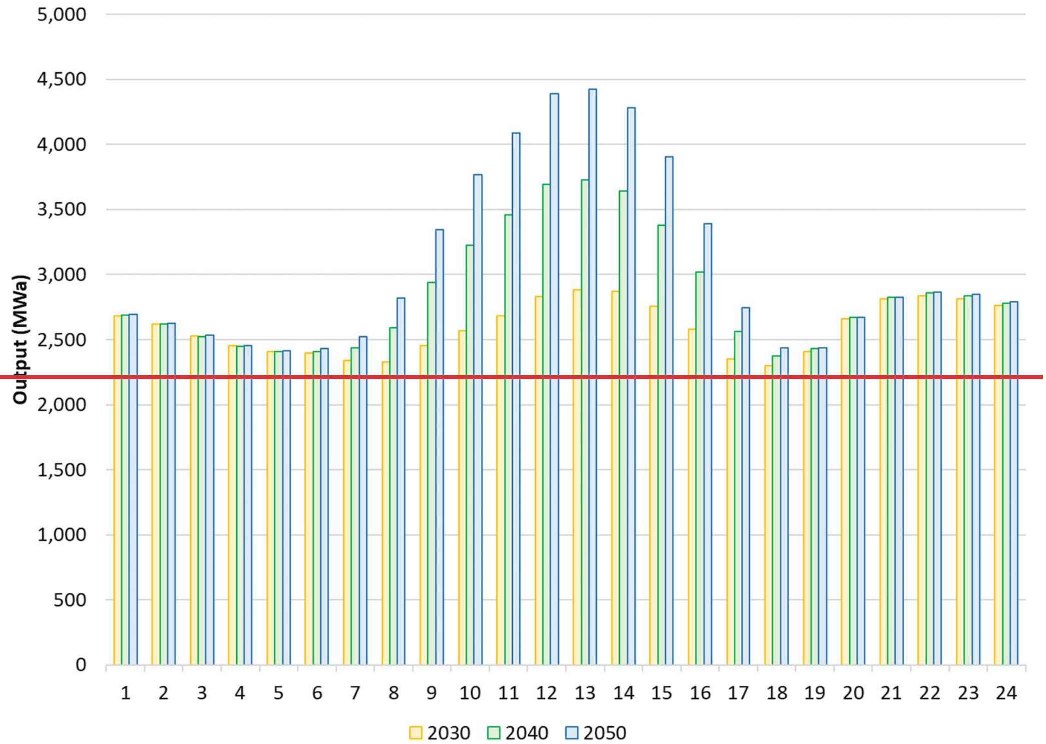


Figure 24~~17~~ Hourly Average RPS Output PJM ComEd



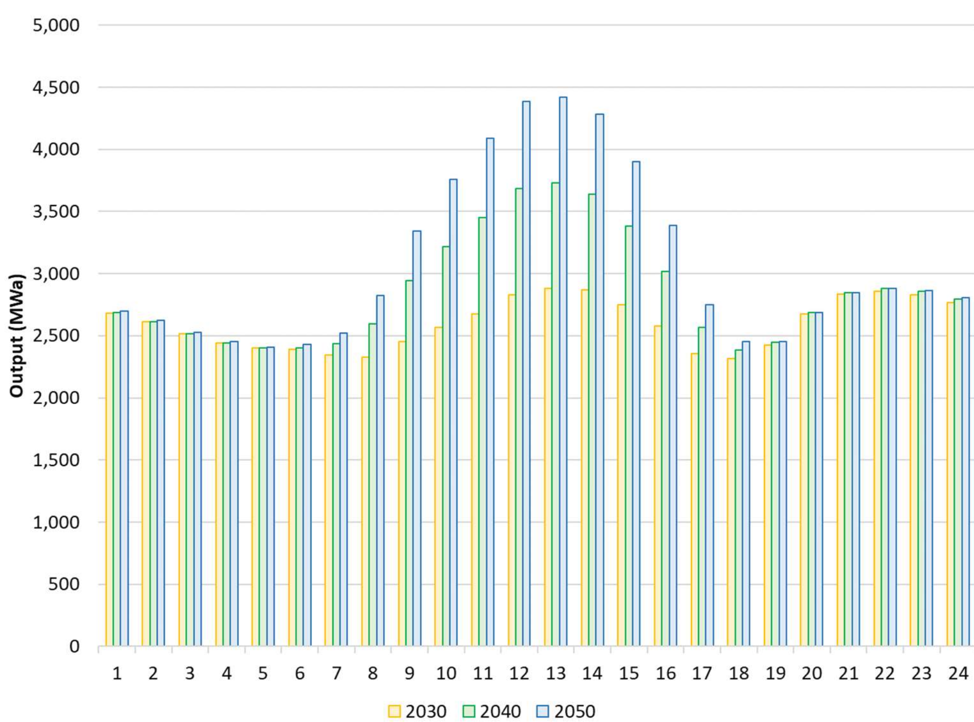
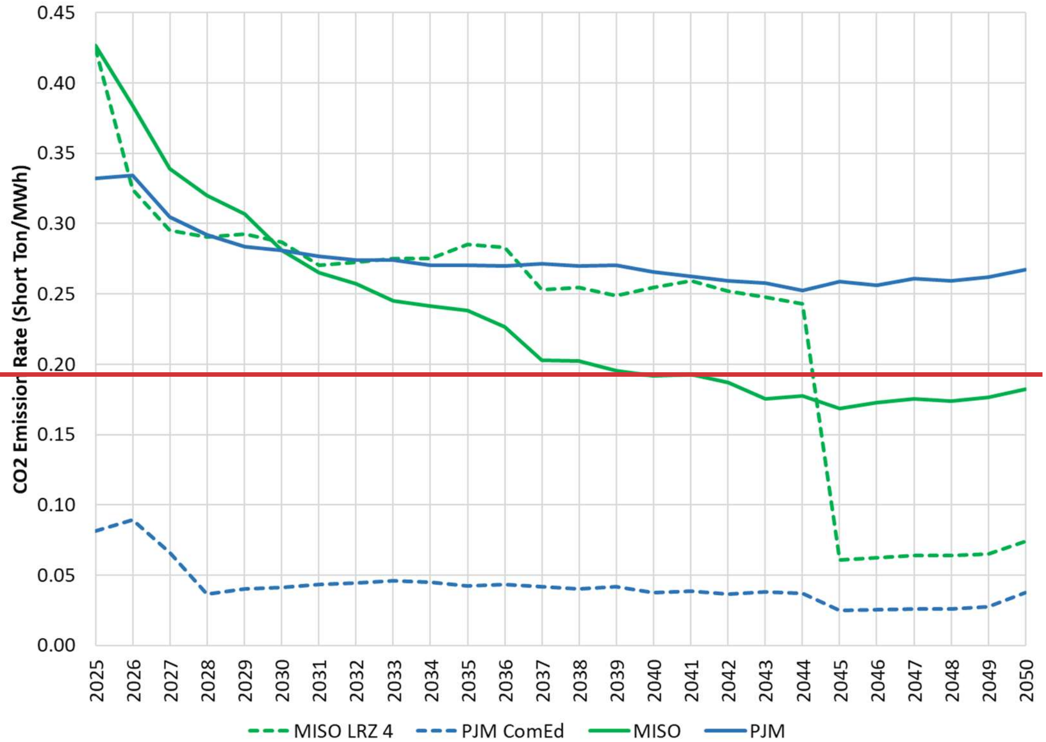
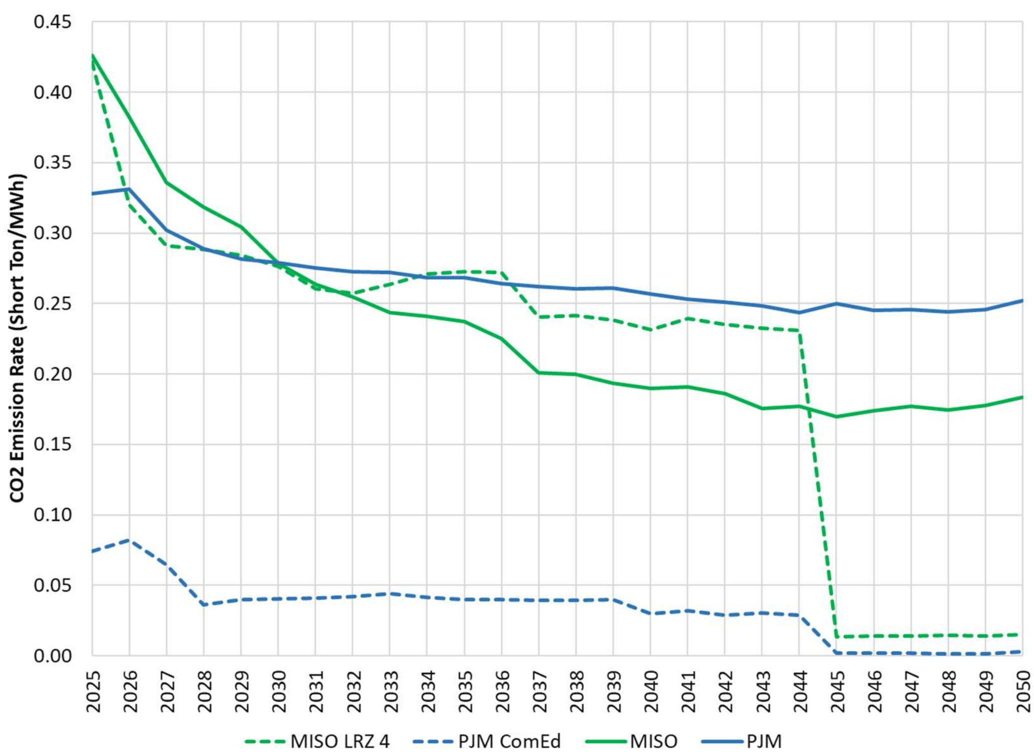


Figure 25~~18~~ CO_2 Emission Rate





Due to the shift in the resource mix towards cleaner energy sources, the CO_2 emission rate has shown a consistent decline over the studied period. MISO exhibits a more pronounced and steeper decline compared to PJM due to a more aggressive postulated renewable buildout. In MISO LRZ 4, there is a step change in 2045, attributed to the phased-out fossil plants, particularly coal-fired generators that are allowed to remain in system. The CO_2 emissions rate for MISO LRZ4 shown in Figure 25 has decreased relative to the draft Policy Study due to an error in Energy Exemplar's database, which mis-classified the location of one fossil plant as in-state, and has since been corrected. The remaining emissions in MISO and PJM after 2045 are attributable to smaller generators that do not meet the size requirements for CEJA and therefore are not closed.

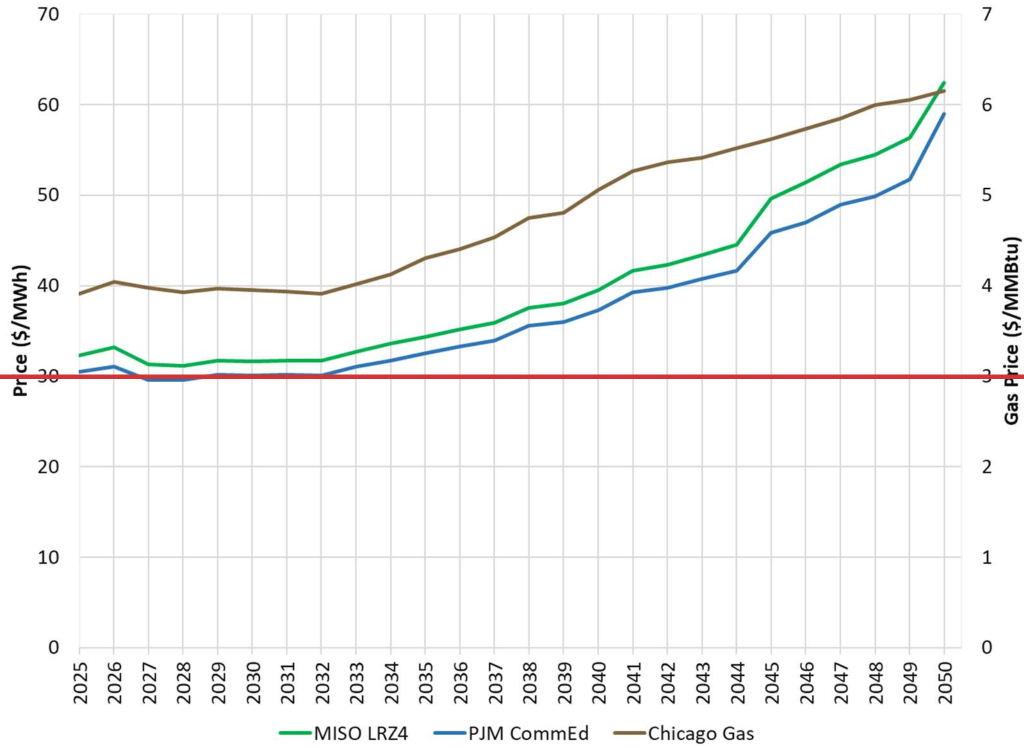
~~However, as the study period concludes, there is a slight uptick in both CO_2 emission amount and rate in both RTOs. This increase is attributed to a higher utilization of gas generation, necessary for meeting baseload and peak-hour demands and ensuring grid reliability. The rise in gas generation is particularly crucial in light of the substantial penetration of intermittent renewable resources in both MISO and PJM.~~

2.2.1 Energy Prices

Throughout the study period, the relationship in the annual average energy prices remains consistent among MISO LRZ 4, ComEd, and Chicago gas prices. Specifically, the price in MISO Zone 4 tends to be approximately $2.5/MWh higher than in the ComEd zone. Following the retirement of fossil generation under CEJA, there is a widening of the price gap, reaching $4.~~3~~2 per MWh. MISO LRZ 4 and PJM ComEd both undergo a comparable average annual price increase of approximately ~~2.7~~3%. However, there is a significant spike in the annual power price growth rate in 2045 to ~~10~~11%, attributed to the impact of CEJA which makes import constraints into Illinois zones bind more often, and takes gas generation off the margin. In contrast, the Chicago gas price sees a slightly lower average annual increase, specifically at 1.8%. Energy prices projected for 2030 are similar to the last 12 months of power prices at the PJM Chicago Hub, which averaged $30/MWh, or the ~~MIS~~MISO Illinois Hub, which averaged $33/MWh.[82] Power prices increase with gas commodity from 2025-2040, and experience further pressure from load growth and fossil retirements by the end of the Study Period.

[82] Prices sourced from S&P Capital IQ.

Figure 26~~19~~ Zonal Energy Price



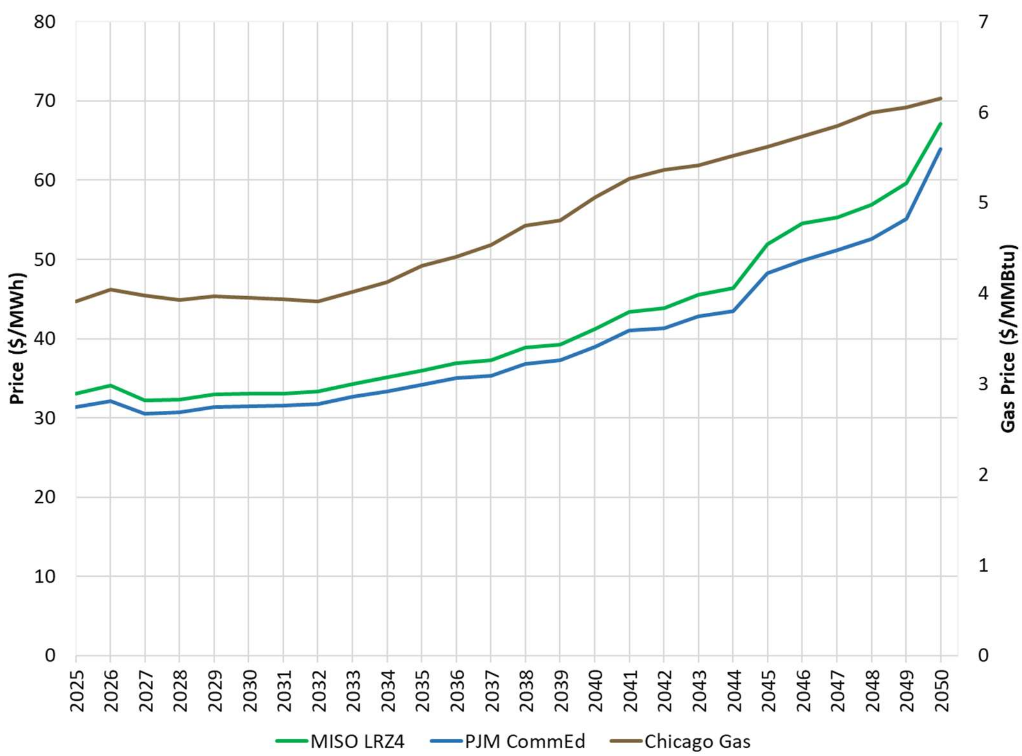
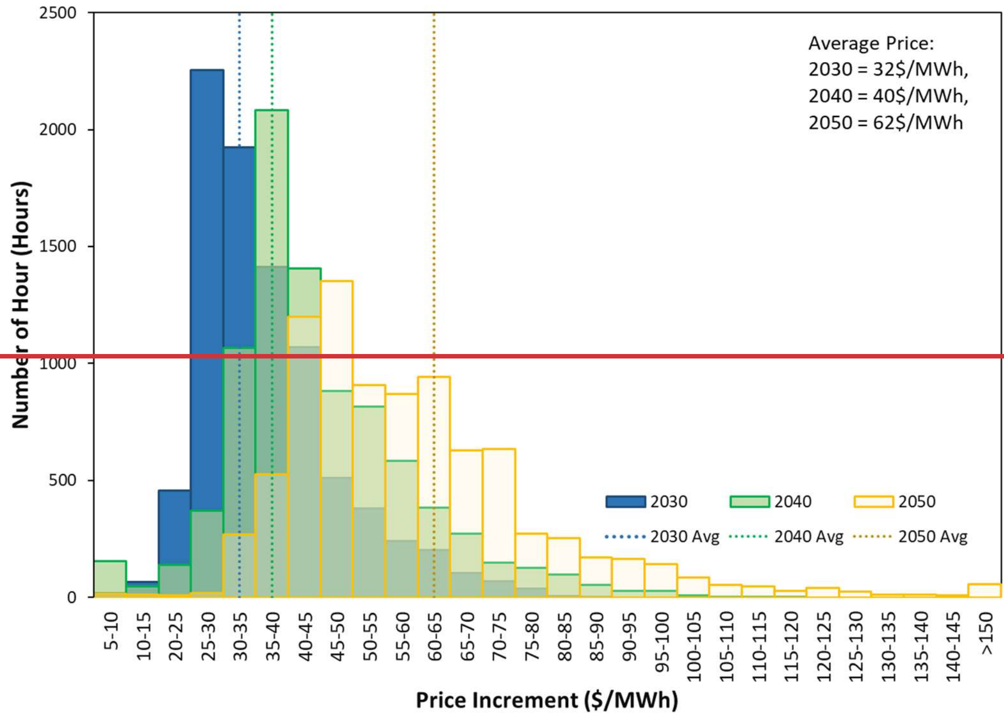
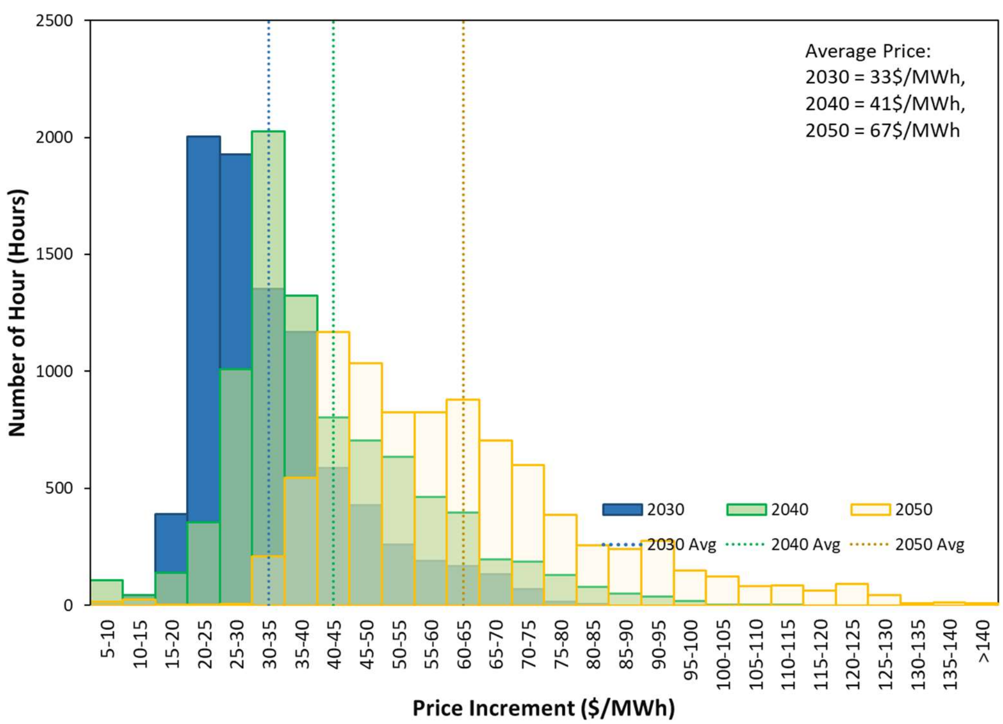


Figure ~~20~~ 27 Hourly Energy Price Distribution in MISO LRZ4



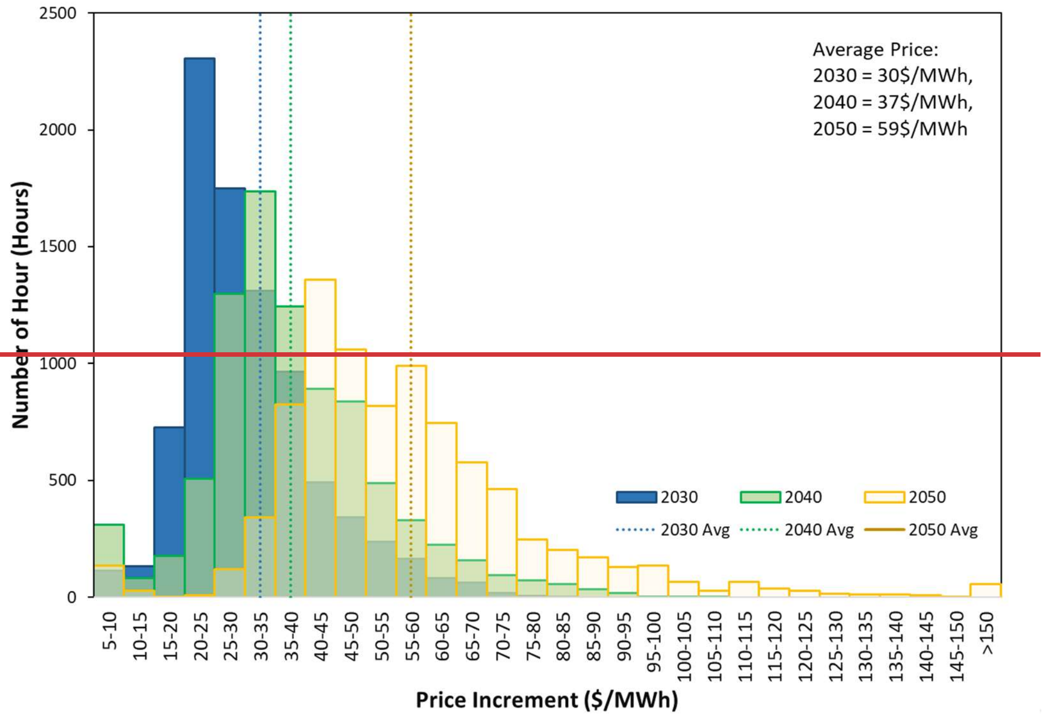


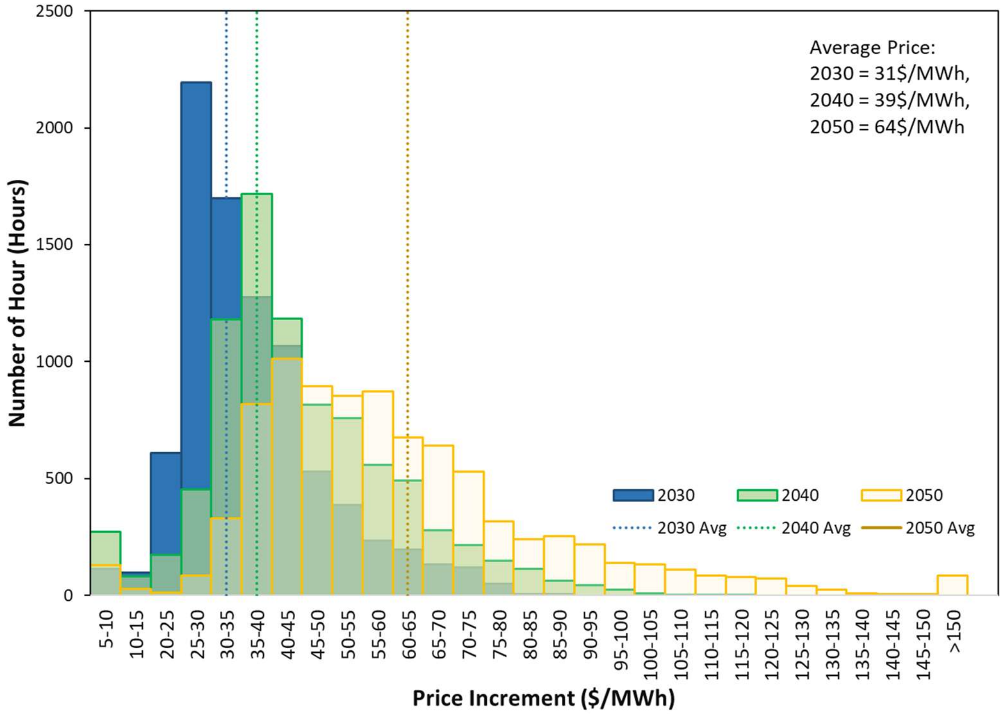
Plotting the frequency of prices in five-dollar ranges in snapshots for specific years (2030, 2040, and 2050) in MISO LRZ 4 reveals a notable shift in the distribution of hourly prices over the study period. In 2030, the distribution exhibits a strong positive skew to the right, suggesting a concentration of lower prices with a few higher-priced outliers. This distribution tendency evolves toward a more central distribution in 2050, indicating a balance between lower and higher prices.

Examining specific price ranges, the largest share of hours falls within the \$20 to \$25/MWh bin in 2030, shifts to the \$~~35~~30 to \$~~40~~35/MWh bin in 2040, and further increases to the \$~~45~~40 to \$~~50~~45/MWh bin in 2050. This progression reflects a trend of increasing hourly prices over the years.

In 2050, hourly prices exhibit greater variability, spanning a wider range from \$30/MWh to \$~~80~~95/MWh. This increased variability reflects the volatility created by intermittent renewable resources and indicates stronger benefits for energy storage.

Figure 28~~21~~ Hourly Energy Price Distribution in PJM ComEd



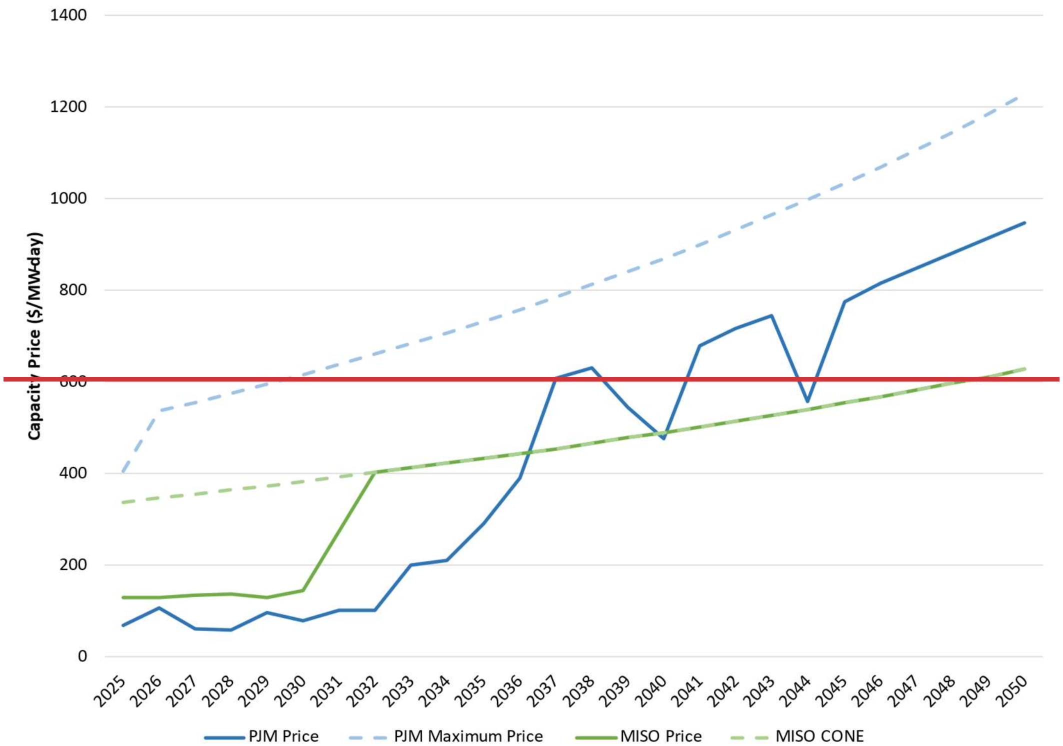


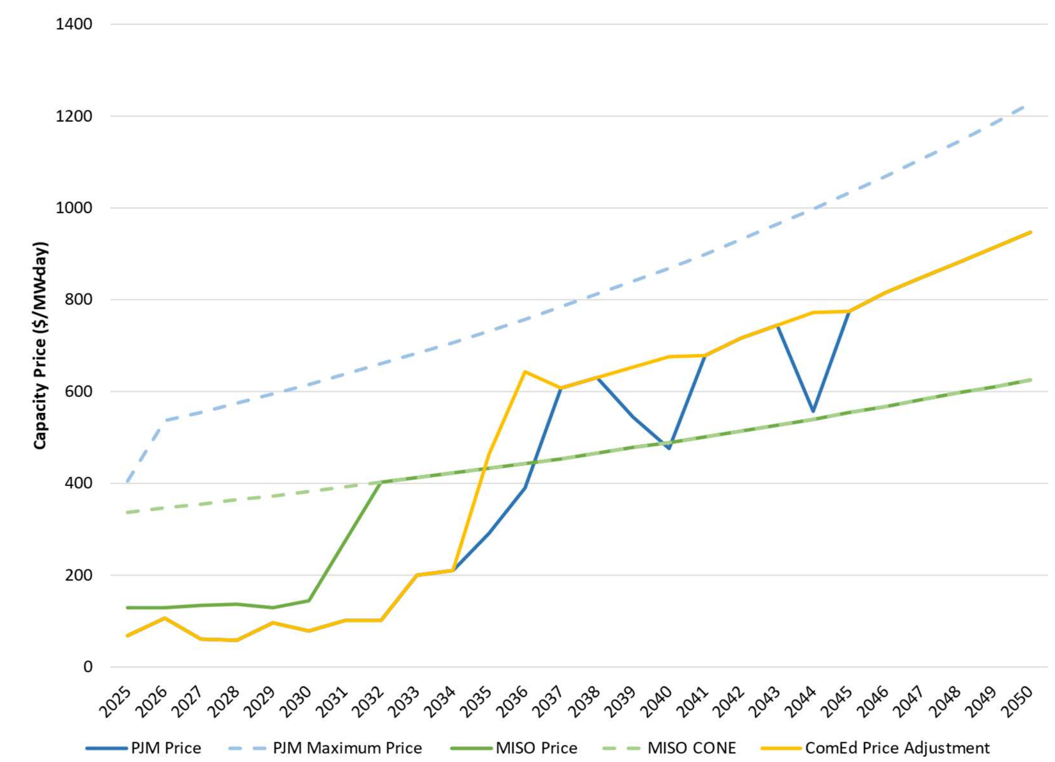
Similarly, analyzing the hourly prices in PJM ComEd reveals a pattern of distribution changes over the study period. In 2030, the distribution has a strong positive skew to the right, indicating a concentration of lower prices with a few higher-priced outliers. Examining specific price ranges, the largest share of hours falls within the $~~20~~25 to $~~25~~30/MWh bin in 2030, shifts to the $~~30~~35 to $~~35~~40/MWh bin in 2040, and further increases to the $40 to $45/MWh bin in 2050. In 2050, hourly prices exhibit greater variability, spanning a wider range from $30/MWh to $~~80~~95/MWh.

2.2.2 Capacity Prices

Capacity prices are very difficult to forecast past the prompt year (i.e. the next delivery year that will be cleared via auction). PJM and MISO are continually changing the market rules in their tariff. Both RTOs have recently added seasonal components to their capacity markets, and MISO has currently made a proposal to add a sloped demand curve to their capacity auctions. Both markets utilize the CONE, the projected costs of a generic new unit, as a guidepost for the market price when resource margins are tight or deficient. Since capacity is supposed to represent the “missing money” to secure investment in new (and existing) resources to provide resource adequacy, the logic is that the price cannot be higher than the cost of a new generating unit that is well-suited to provide capacity. As a first approximation, it follows that when an RTO faces tight capacity supply conditions (i.e. just enough resources to meet peak demand and reserve margin), the capacity price will rise to be CONE or net CONE after other revenues from wholesale markets (energy and ancillary services) are credited out.

Figure 29~~22~~: Capacity Price Forecast





Aurora's capacity expansion functionality was utilized to determine capacity prices for PJM. For MISO, no long-term case was modeled to determine capacity prices, since the forecast started with a static resource expansion from MISO Future 1 modeling results. However, MISO Futures modeling indicates that surplus accredited capacity will dwindle over time, with the RTO becoming tight starting in 2032.[83] Prices were assumed to clear at CONE, MISO's administrative price ceiling, thereafter and CONE was escalated at inflation. Both RTOs will need to add capacity to counterbalance fossil unit attrition, particularly coal-fired steam turbines facing new environmental rules and state and utility initiatives.

In comments on the draft Policy Study, the Energy Storage Associations recommended including "… a historically-based price escalator to ComEd Zone capacity prices." [84] The report cited the average differential between the RTO and ComEd clearing prices from the 2018-2019 to 2023-2024 delivery years, which averaged $56.52/MW-day.[85] It is unclear why the clearing price from the 2024-2025 BRA was omitted from this analysis; the most recent BRA cleared at $28.92/MW-day in RTO, and ComEd did not separate in price.[86] Over the last two years, the ComEd price has not separated from the RTO, and in 2022-2023 the premium was relatively small ($18.96/MW-day). In that year, several nuclear facilities failed to clear the BRA which have since appeared to clear.[87,88] More recent auction outcomes do not suggest that price separation should be factored in using a historical escalator. The assumed CONE values that drive the forecasts are conservative in nature, as CONE may become more expensive in the face of decarbonization initiatives. ~~As an example, NYISO has previously~~However, some adjustments to the forecasted capacity price are warranted. Most directly in this case, on January 19, 2024 FERC issued an order accepting PJM's tariff revisions to separate ComEd into a new CONE Area 5 from CONE Area 3.[89] Due to the recency of that order, the draft Study was not updated to reflect that new CONE. To account for the expected retirement of the CONE combined-cycle unit in 2045 under CEJA, the assumed asset life of the resource will be stepped down from the 20-year default value. In that proceeding, a PJM witness estimated that by 2029/2030, the CONE Area 5 would have an 8.2% higher Gross CONE value due to the reduction in asset life to 15.5 years from the standard 20-year assumption.[90] Based on a review of the workpaper source for those calculations, by the 2034/2035 delivery year (10.5 year asset life, ComEd

[83] MISO Futures Report, Figure 51.

20231002 LRTP Workshop - Draft Series1A Futures Report630365.pdf (misoenergy.org)

[84] Energy Storage Associations Comments to the IPA Draft Policy Study, page 10.

[85] *Id.* page 9, table 3.

[86] PJM BRA Report, see page 5, table 2.

https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2024-2025/2024-2025-base-residual-auction-report.ashx

[87] S&P Global Market Intelligence, "3 Exelon nuclear plants fail to clear PJM Capacity Auction", accessed Feburary 27, 2024. 3 Exelon nuclear plants fail to clear PJM capacity auction | S&P Global Market Intelligence (spglobal.com)

[88] See BRA Report, page 11, Table 7.

[89] See Order Accepting Tariff Revisions, issued January 19, 2024 in FERC Docket ER24-462-000. FERC Order Accepting CONE Filing in ER24-462-000.docx (pjm.com)

[90] See affidavit of Gary Helm, filed November 21, 2023 in FERC Docket ER24-462-000, Table 1 on page 6.

20241121-er24-462-000.pdf (pjm.com)

would have an 28.6% higher CONE than the neighboring regions.[91] Given the higher CONE value (and hence higher VRR curve assumptions) utilized in the Area 5 filing, the modeling team re-assessed whether ComEd would separate from the RTO forecast before PJM at large required new build and the final Policy Study includes the use of an adjusted CONE for ComEd. The VRR curves were estimated using the escalating CONE adjustment per economic life, and the supply demand balance indicated that the ComEd price would separate following the second wave of fossil fuel retirements in 2035. The clearing price was not assumed to separate indefinitely as PJM at large clears around its reserve margin from 2037 on and the Area 5 CONE premium eventually would be replaced by another reference unit calculation. The reductions in capacity price seen in 2038-2040 and 2044 were eliminated, as ComEd would not be in a surplus condition as the RTO was in those periods.

As the economic life of the combined cycle reference unit used in the Area 5 CONE calculation dwindles, it is likely that capacity prices are benchmarked by a clean energy asset in PJM that becomes more competitive. NYISO has also utilized a short amortization period for its CONE calculation for fossil generators to account for Climate Act compliance, which requires a zero-emissions power grid by 2040. NYISO is currently considering battery storage technologies and zero-emissions retrofits for gas turbines in its current CONE review cycle.[92] As battery storage may become the "reference" CONE unit in PJM or MISO in the future, capacity markets will provide a strong revenue stream to make prospective storage projects viable.

Indirect (market price) impacts of adding incremental capacity into MISO and PJM were not estimated. Perturbing the capacity expansion model makes creating a "but for" test for energy and environmental effects difficult. Resource additions may be deferred and retirements accelerated in response to a new addition, which may lead to limited or no net change in prices. Changes to the resource mix besides the policy cases considered would also reduce the energy market impacts. While there is some indirect capacity market benefit, counting such a benefit to be wholly additive against a "but-for" energy market test inflates the combined value of energy and capacity market impacts. In comments on the draft Policy Study, SOO Green raised the indirect capacity price benefit of the project and touted the use of PA Consulting's RPM model in bid advocacy for various clean energy projects.[93] While bidders may have adopted these price impacts in proposal narratives supporting project selection, state commissions have not used them as the basis for project selection or the calculation of rate impacts. The New York State Public Service Commission did not include capacity price benefits in their calculation of rate impacts.[94]

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[91] See CONE workpapers: https://www.pjm.com/-/media/committees-groups/committees/mic/2022/20220520-special-session/pjm-2022-cone-workbook-ct-cc-battery-storage----public-version----informational-only.ashx after adjusting the debt and equity rates to match footnote 11 of the Helm affidavit, the asset life factor calculation could be reasonably approximated.

[92] NYISO 2025-2029 ICAP Demand Curve Reset, November 8, 2023 presentation to the ICAP Working Group Meeting by 1898 Co. PowerPoint Presentation (nyiso.com)

[93] PA Consulting identified the potential wholesale capacity cost savings of the SOO Green project as approximately $4.02 billion in nominal dollars from 2030-2049 using its RPM model. The modeling team does not have a separate Reliability Pricing Model (RPM) simulation model in place.

See SOO Green comments, pages 5-6.

[94] Order Approving Contracts for the Purchase of Tier 4 Renewable Energy Certificates, New York Public Service Commission Case 15-E-0302, issued April 14, 2022. See page 131: "The Commission does not agree with CPNY and

The New Jersey Board of Public Utilities does not use capacity price suppression as a basis for their selection of offshore wind projects.[95] The Maryland Public Service Commission did consider reductions in energy and capacity prices, but consultants for Maryland Staff and Skipjack did not place any value on capacity price reduction in their impact calculations.[96] Project developers have a strong incentive to estimate large energy and capacity benefit calculations to support project selection and contract approvals, but policy makers generally take a more conservative approach.

2.3 Policy Proposal Case Results

Case results are presented with benefits quantified and compared against potential costs. As explained in section 1.8, costs were estimated and levelized over 20 years for the offshore wind and storage projects. For SOO Green, annual contract costs are posited for a 25-year term. The policy proposals would be commercialized in procurements oriented around an indexed product, RECs in the case of offshore wind and SOO Green and Energy storage credits in the case of storage. Developers offer the costs of the policy proposals, plus return on investment as a "strike price". Ratepayers then cover the difference between the strike price and energy and capacity revenues from the wholesale market.

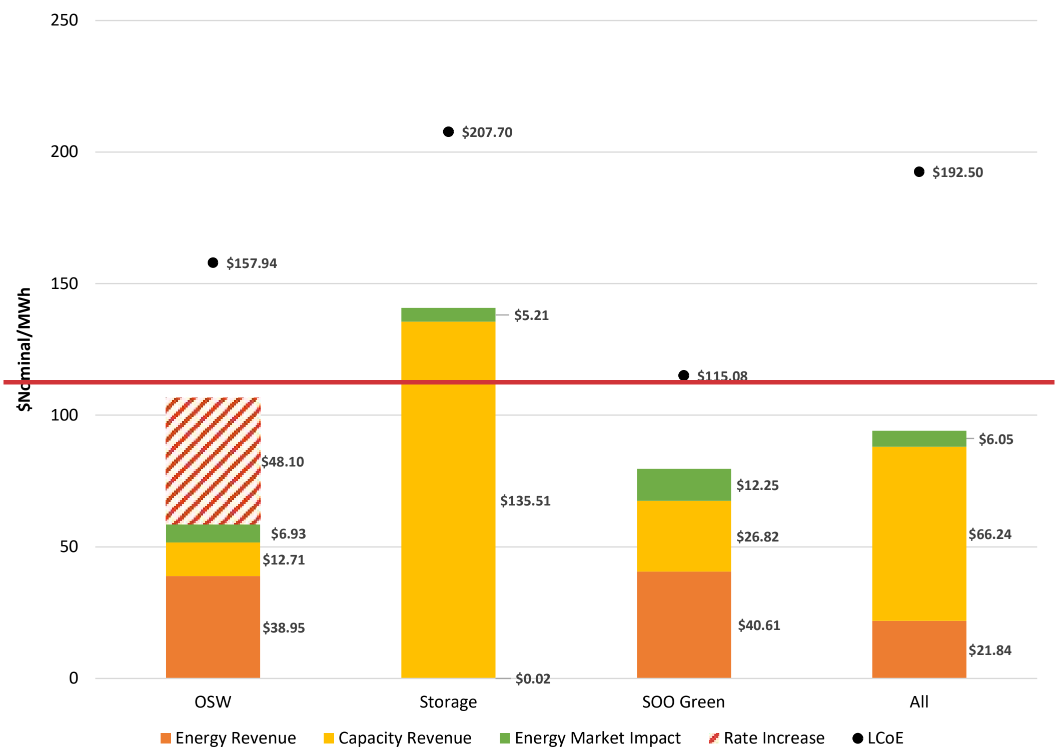
To place the strike prices estimated for the policy projects in context, the average winning bid price for the December 2023 procurement for utility scale wind and solar projects was about $75/MWh. The June 2023 procurement averaged about $70/MWh. The LCoEs shown below indicate that the strike prices for the policy projects would range from about $115/MWh to $210/MWh. For SOO Green the market forecasts indicate that ratepayers will need to pay indexed RECs at an average of $50/MWh over the 20-year modeled period. The rate increase of 0.25% posited under ~~SB1699~~HB 2132 to fund the offshore wind pilot program is shown for comparison in the futures below; as posited it falls ~~far~~ short of meeting the costs to make a pilot project commercially viable, but only price discovery through commercial negotiations can reveal the actual costs of the project. The wholesale energy cost reduction for electric demand in Illinois, which is calculated as the product sum of hourly energy prices multiplied by hourly demand, represents an indirect benefit of the project. Wholesale energy cost reduction is calculated for both ComEd and MISO LRZ4 in all policy cases. The reduction in wholesale energy costs caused by adding ~~the~~ SOO Green is $~~12.25~~22.80/MWh. The figures below summarize the revenues, wholesale energy cost reduction (energy market impact), and LCOE. Figure 30~~Figure 23~~ and Figure 31~~Figure 24~~ are reported in nominal and 2022 real dollars ("$2022"), respectively. Figure 32~~Figure 25~~ discounts the values using a 2% discount rate (which represents a societal discount rate based on long-term Treasury bond yields).

HQUS that the wholesale market price suppression caused by these projects would be so large, and so permanent, that signing contracts with a strike price of up to around $94 per MWh would actually save ratepayers money."

[95] The latest Board orders approving Offshore Wind Solicitation 3 are here: Board of Public Utilities | January 24, 2024 (Wednesday) (nj.gov)

[96] Order Granting Offshore Wind Renewable Energy Credits, Maryland Public Service Commission Case 9666, issued December 17, 2021.

Figure 30~~23~~: Summary Projections, 2030-2049 (Nominal)



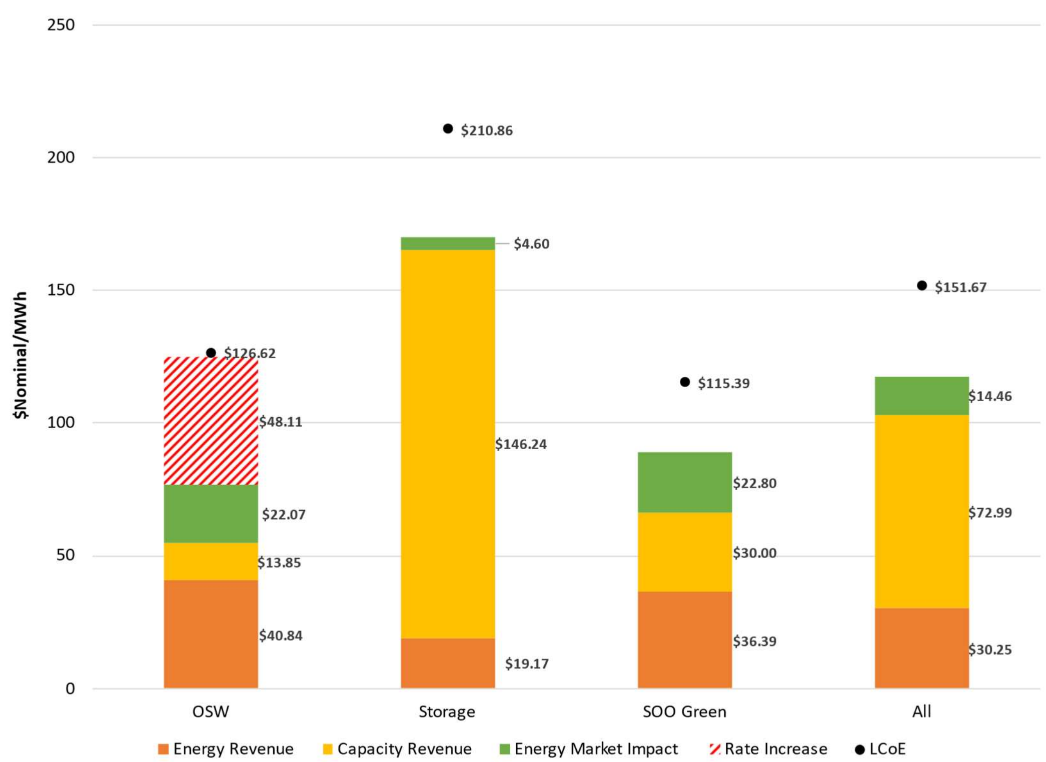
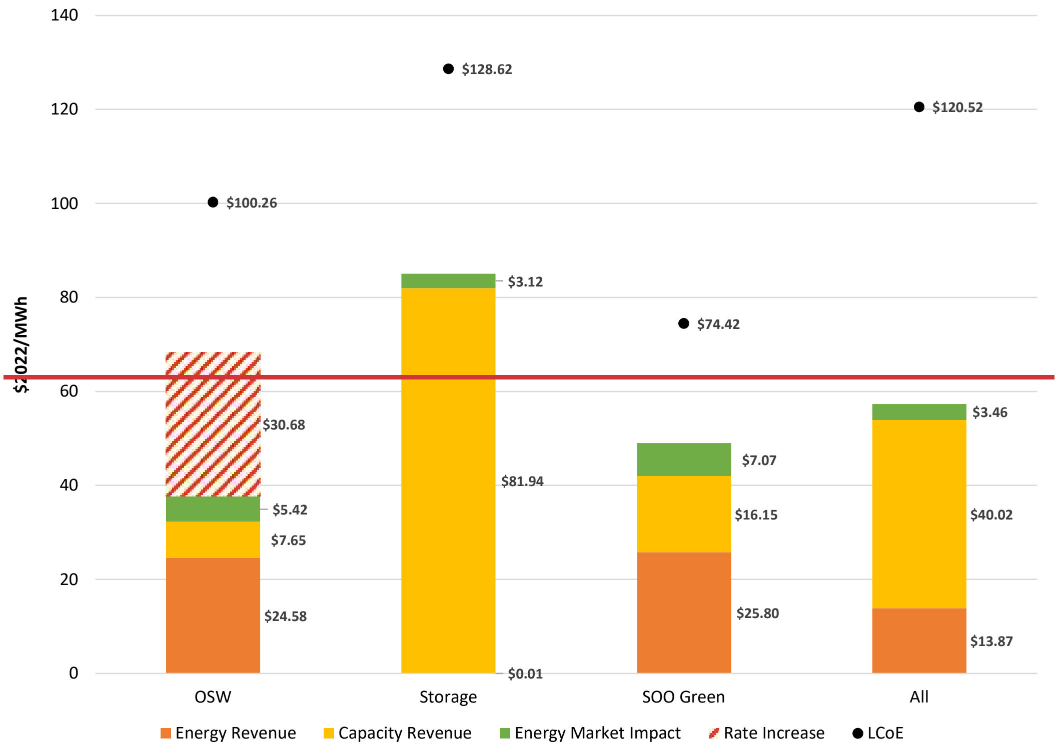


Figure 31~~24~~: Summary Projections, 2030-2049 ($2022)



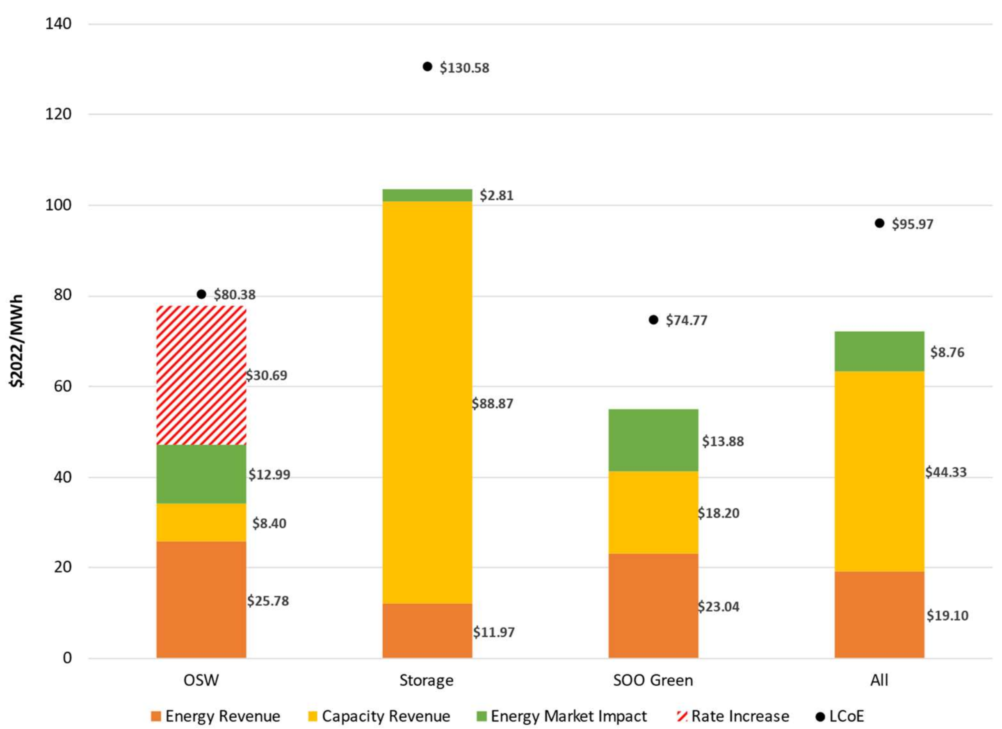
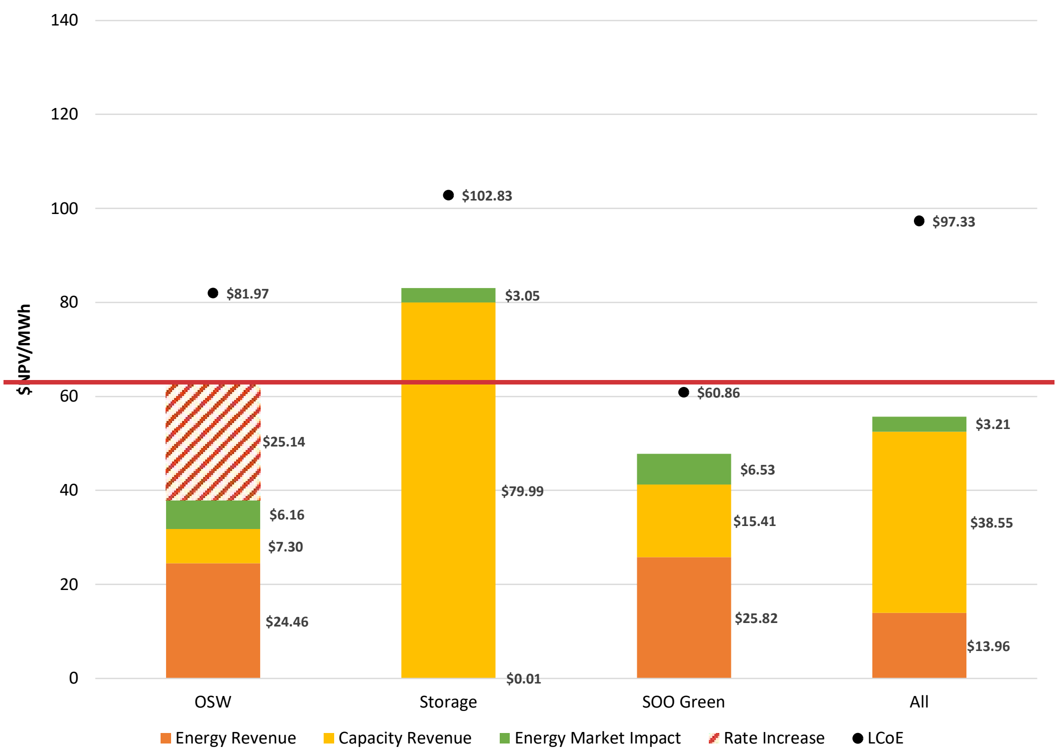
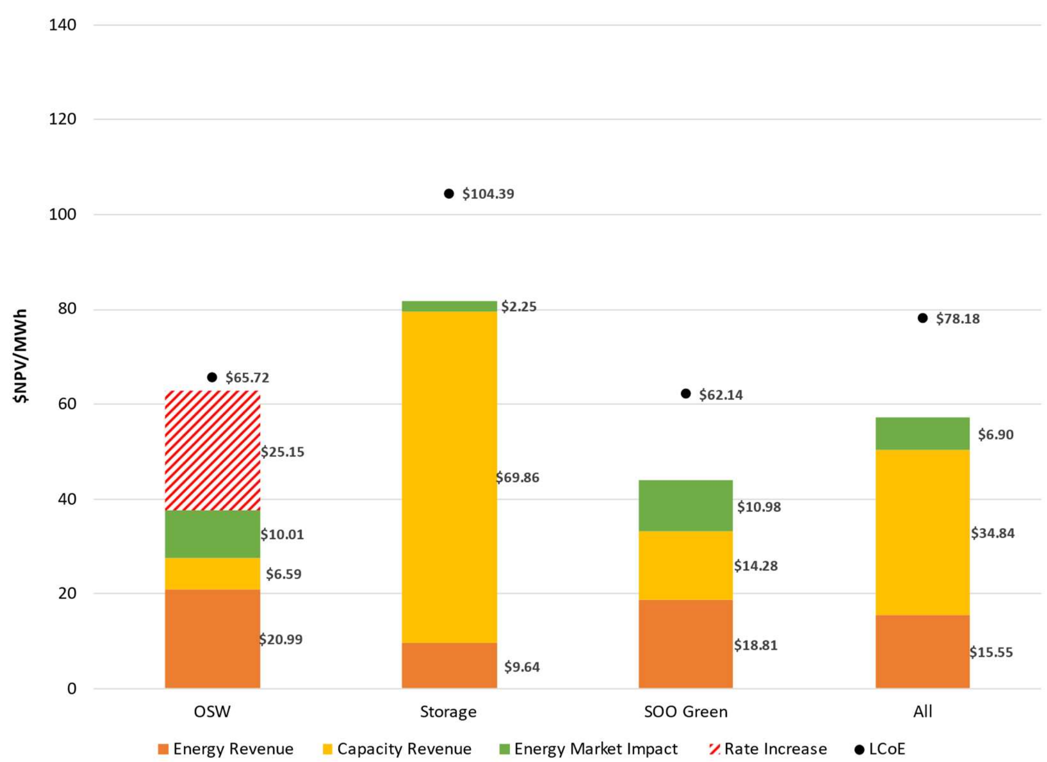


Figure ~~25~~32: Summary Projections, 2030-2049 (NPV with 2% Discount Rate)





The costs of these policy options will all represent an increase relative to current costs of power for Illinois ratepayers. Per EIA data, Illinois ratepayers paid about 10 cents per kWh, or $100/MWh of electricity, which includes charges for transmissions and distribution. Energy-only providers billed about 6 cents per kWh, or $60/MWh.[97] As shown in ~~Figures 23, 24 and 25,~~Figure 30, Figure 31 and Figure 32, the levelized cost of electricity under each initiative exceeds the energy and capacity revenue and market impact offsets, so the proposals would contribute to increasing electricity costs in Illinois if implemented. The net rate impact of the proposals is the shortfall between the LCoE and the stacked bars. Illinois ratepayers will have to directly pay the shortfall between the strike price and revenue offsets, but that index REC cost will be indirectly reduced via wholesale price reductions in the Energy Market Impact. ~~Figure 26~~Table 5 summarizes energy revenues, capacity revenues, and energy market impact by individual case. ~~Figure 27~~

Table 6 summarizes CO_2, SO_2, NO_x and $PM_{2.5}$ emissions reductions by case. CO2 reductions impacts are calculated for the entire Study Region. Criteria pollutants are calculated in-state to better estimate damages for Illinois residents. The emissions impacts attributable to each policy have changed relative to the draft study, due to modeling corrections for the retirement of gas-fired generation in Illinois and the retirement of nuclear plants outside of Illinois. Some criteria pollutant results have changed from the initial workpaper release due to a mis-classification of a fossil unit as in-state. For the offshore wind case, criteria emissions increased slightly from the base case. This is a departure from the results presented in the Draft Study, which showed SO_2 and NO_x decreasing with the introduction of offshore wind. While offshore wind decreases the dispatch of fossil units in the study region at large, most of the reduction in fossil dispatch (and associated CO_2 reduction) occurs outside of Illinois. The intermittent profile of incremental offshore wind causes increased dispatch of flexible peaking resources to follow load net renewable energy, which creates a very small increase in SO_2 and NO_x emissions within Illinois.

Table 5~~2~~: Summary Projections, 2030-2049 Contract Period ($1,000 Nominal)

Case	*Costs*	*Energy Revenue*	*Capacity Revenue*	*Net Market Revenues* $1,000 Nominal	*Energy Market Impact*	*Total*	*Energy Output* GWh
OSW	2,158,740	532,408	173,669	-$1,452,663	94,711	-1,357,952	13,668
Storage	33,916,273	2,650	22,127,646	-$11,785,977	850,151	-10,935,826	163,294
SOO Green	39,633,821	10,786,691	7,123,211	-$21,723,920	3,254,217	-18,469,703	265,620
All	85,115,605	9,656,633	29,288,778	-$46,170,194	2,676,269	-43,493,925	442,148

Case	*Costs*	*Energy Revenue*	*Capacity Revenue*	*Net Market Revenues* $1,000 Nominal	*Energy Market Impact*	*Total*	*Energy Output* GWh
OSW	1,730,410	558,104	189,265	-$983,041	301,629	-681,412	13,666
Storage	33,916,273	3,082,900	23,522,586	-$7,310,787	739,111	-6,571,676	160,849
SOO Green	29,643,047	9,348,275	7,707,964	-$12,586,808	5,858,042	-6,728,767	256,891
All	65,289,730	13,023,447	31,419,815	-$20,846,468	6,224,719	-14,621,749	430,469

[97] See EIA form 861.

Table 6~~3~~: Emissions Impact Summary, 2030-2049 Contract Period

Case	*CO2*	*SO2* (Tons)	*NOx*	*PM2.5*
OSW	7,805,663	1,139	598	47
Storage	29,620,394	12,392	28,976	800
SOO Green	145,123,573	38,539	63,871	2,102
All	167,678,290	44,612	91,395	2,740
Case	***CO2* (tons/MWh)**	***SO2***	***NOx* (lbs/MWh)**	***PM2.5***
OSW	0.57	0.17	0.09	0.01
Storage	0.18	0.15	0.35	0.01
SOO Green	0.55	0.29	0.48	0.02
All	0.38	0.20	0.41	0.01

Case	*CO2*	*SO2* (Tons)	*NOx*	*PM2.5*
OSW	7,488,714	-137	-129	21
Storage	27,309,080	8,223	15,528	701
SOO Green	152,660,227	7,722	6,172	975
All	187,073,709	18,367	20,872	1,725
Case	***CO2* (tons/MWh)**	***SO2***	***NOx* (lbs/MWh)**	***PM2.5***
OSW	0.55	-0.02	-0.02	0.00
Storage	0.17	0.10	0.19	0.01
SOO Green	0.59	0.06	0.05	0.01
All	0.43	0.09	0.10	0.01

The environmental benefits associated with the policy proposals stem from the additional renewable energy generation that the proposals would make possible. These benefits primarily involve avoiding the pollutants that would have been emitted from electricity generated by the combustion of fossil fuels in the absence of additional renewable generation made possible by the policy proposals. Emissions from the combustion of fossil fuels—specifically, particulate matter ($PM_{2.5}$),[98] sulfur dioxide (SO_2) and nitrogen

[98] PM emissions are generally reported as either PM_{10}, particulates that have diameters of 10 micrometers or less, or $PM_{2.5}$, particulates of 2.5 micrometers or less.

oxides (NO_x)—are linked to a wide range of adverse health effects. These pollutant emissions can also damage the surfaces of agricultural crops adversely affecting growth rates and yields. Carbon dioxide (CO_2), emitted by the combustion of fossil fuels, contributes to climate change. CO_2 also indirectly impacts public health concerns through reduced agricultural production, increased waterborne and pest-related diseases, increased storm severity, and ocean acidification.[99]

Emissions that are displaced by renewable generation can be determined with reasonable specificity, however, assigning monetary values to these emissions benefits is subject to significant uncertainty. Considering this uncertainty, in this report, the monetary benefits of the emissions displaced by ~~the additional wind and solar generation that would result from~~ the implementation of the policy proposals are reported as ranges.

Several studies[100,101,102] developed estimates for the marginal costs from electricity generation emissions. The ranges of costs in dollars per ton emitted are based on the monetary values reported in these studies converted to 2022 dollars:[103]

Table 74: Ranges for ~~Criteria~~ Pollutant Damages (2022 $/ton)

Pollutant	Costs (2022 $/ton)	
	Minimum	Maximum
~~SO_2~~	~~7,900~~	~~35,000~~
NO_2	2,200	16,700
$PM_{2.5}$	12,900	120,700

99 U.S. Environmental Protection Agency, Air Pollution: Current and Future Challenges, www.epa.gov/clean-air-act-overview/air-pollution-current-and-future-challenges, updated October 23, 2023, accessed November 11, 2023.

100 Jaramillo, P. and Muller, N., "Air pollution emissions and damages from energy production in the U.S.: 2002-2011, Energy Policy 90 (2016) pp.202-211.

101 Goodkind, A.L. et al, "Fine-scale damage estimates of particulate matter air pollution reveal opportunities for location-specific mitigation of emissions," PNAS, April 30, 2019, vol. 116, no. 18, 8775-8780, www.pnas.org/cgi/doi/10.1073/pnas.1816102116.

102 Holland, S.P.; Mansur, E.T.; Muller, N.; Yates, A.J.; Decompositions and Policy Consequences of an Extraordinary Decline in Air Pollution from Electricity Generation, NBER Working Paper 25339, December 2018.

103 Prices escalated using St. Louis Reserve Bank Price Indexes for Domestic Product. Release Tables, Table 1.1.4 Annual~~-~~, https://fred.stlouisfed.org

Pollutant	Costs (2022 \$/ton)	
	Minimum	Maximum
CO_2	15.5	152
SO_2	7,900	35,000
NO_2	2,200	16,700
$PM_{2.5}$	12,900	120,700

The differences among the ~~studies~~studies' cost estimates highlight the considerable uncertainties associated with the estimation of monetary values for emission costs. These estimations are dependent on a varying range of assumptions and inputs between studies.

Estimates of the avoided costs from displaced CO_2 emissions are based on the social cost of carbon. The U.S. EPA defines the social cost of carbon (social cost of greenhouse gases) as the "monetary value of the future stream of net damages associated with adding one ton of greenhouse gas to the atmosphere". This metric includes: "the value of all climate change impacts (both negative and positive) including (but not limited to) changes in net agricultural productivity, human health effects, property damage from increased flood risk, changes in the frequency and severity of natural disasters, disruption of energy systems, risk of conflict, environmental migration, and the value of ecosystem services." From the EPA's perspective, the social cost of carbon includes the costs and benefits associated with CO_2 emissions that can be quantified. Each ton of CO_2 emitted results in both local and global impacts. While CO_2 emissions have global impacts, the EPA's quantification of the costs is focused on the costs and benefits that affect individuals and accrue to entities in the U.S.

The social cost of carbon is typically presented in terms of dollars per ton of CO_2. The social cost of carbon measures the estimated future costs from carbon emissions in terms of present value using a discount rate. Since 2008 the estimated values for the social cost of carbon have evolved based on growing scientific data that improved the understanding of the impacts of greenhouse gas emissions. This evolution generated considerable political controversy as the values of the social cost of carbon changed.

The Agency took into consideration a range of values for the social cost of carbon used to determine the benefits of displaced CO_2 emissions. The lower end of the range reflects the domestic social cost of carbon (in 2020 dollars escalated to 2022 dollars) of \$15.50/ton determined using a 5% discount rate.[104,105] This value for the social cost of carbon is based on estimates and calculations by the Interagency Working Group ("IWG") developed in 2016. The U.S. EPA's most recent social cost of carbon estimate (November 2023) uses a 2.5 percent discount rate to arrive at a value of \$120/metric ton for 2020. Following the EPA's estimate of the real annual rate of increase of 1.55 percent for this cost, converting the value to 2022\$

[104] Interagency Working Group on Social Cost of Greenhouse Gases, United States Government, February 2021, Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide, Interim Estimates under Executive Order 13990.

[105] For context the \$16.50/MWH Social Cost of Carbon used for the development of the Zero Emission Standard Procurement Plan translates to \$31.37/ton based on a CO_2 emissions factor of 1,052 lbs./MWh.

and converting to tons gives an equivalent social cost of carbon of $152/ton. This is the value that the Agency is using as the upper end of the range of social cost of carbon values for the calculation of displaced CO_2 emissions benefits. Older sources make up the lower-end values for social cost of carbon, and the IPA notes that the damage cost estimates have increased in more recent studies.

The IPA's estimates of the monetized benefits associated with the avoided emissions that would result from the policy initiatives cover a wide range of values to reflect the uncertainties associated with such estimates. These estimates are based on the studies noted in the footnotes. As noted by SOO Green in their comments on the draft Policy Study, other estimates for monetizing emissions benefits, such as those developed using the U.S. EPA's CO-Benefits Risk Assessment (COBRA) tool, are available.[106] Estimates from COBRA are also subject to significant uncertainties affecting the monetized values and are reported as ranges similar to the IPA's ranges of values. A review of the web edition of the COBRA tool using the avoided emissions (tons) determined in the Policy Study analysis shows that the COBRA monetized values overlap or fall within the ranges of the IPA's monetized benefits values.

The IPA estimated the monetized benefits associated with policy proposals based on the estimated emissions avoided as calculated by the Aurora modeling and the costs presented in the previous table. These benefits are shown in millions of 2022$. The monetized emissions benefits attributable to each policy have changed relative to the draft study, due to modeling corrections for the retirement of gas-fired generation in Illinois and the retirement of nuclear plants outside of Illinois. Some criteria pollutant results have changed from the initial workpaper release due to a mis-classification of a fossil unit as in-state, as noted in section 2.1. Monetized benefits become slightly negative for SO_2 and NO_x in the offshore wind case due to a net increase in emissions. This is a departure from the results presented in the Draft Study, which showed SO_2 and NO_x decreasing with the introduction of offshore wind. While offshore wind decreases the dispatch of fossil units in the study region at large, most of the reduction in fossil dispatch (and associated CO_2 reduction) occurs outside of Illinois. The intermittent profile of offshore wind causes increased dispatch of flexible peaking resources to follow load net renewable energy, which creates a very small increase in SO_2 and NO_x emissions within Illinois.

Table 8~~5~~: Monetized Benefits Associated with Policy Proposals (2022 $Millions)

Case	CO_2 Low	CO_2 High	SO_2 Low	SO_2 High	NO_2 Low	NO_2 High	$PM_{2.5}$ Low	$PM_{2.5}$ High
~~OSW~~	~~121~~	~~1,186~~	~~9~~	~~40~~	~~1~~	~~10~~	~~1~~	~~6~~
ESS	459	4,502	98	434	64	484	10	97
HVDC	2,249	22,059	304	1,349	141	1,067	27	254
All	2,599	25,487	352	1,561	201	1,526	35	331

[106] SOO Green Comments on Illinois Power Agency Policy Study, see page 14.

Case	CO_2 Low	CO_2 High	SO_2 Low	SO_2 High	NO_x Low	NO_x High	$PM_{2.5}$ Low	$PM_{2.5}$ High
OSW	116	1,138	-1	-5	0	-2	0	3
ESS	423	4,151	65	288	34	259	9	85
HVDC	2,366	23,204	61	270	14	103	13	118
All	2,900	28,435	145	643	46	349	22	208

The offshore wind resource, which is targeted to represent about 700 GWh annually per HB 2132, would represent about 0.5% of Illinois load when it enters service in 2030. The SOO Green project, which the model estimates would deliver about ~~13,300~~12,800 GWh annually, would represent about ~~9.2~~8.8% of Illinois load.[107] Energy storage systems would not represent incremental energy supply but help mitigate the system peak and balance demand and renewable energy. Compared to approximately 30 GW projected system peak projected in 2030, storage systems would meet about 25% of the peak.

The renewable policy projects are likely to continue operations after the 20-year period examined. Energy storage technologies, particularly batteries, may require significant ongoing investment to counter the degradation of storage capability. Once the assumed 20-year contract expires, Illinois would no longer hold title to environmental attributes from the policy projects. The modeling team conservatively did not count benefits that may accrue after the contracts contemplated in the policy proposals expire.

2.3.1 Offshore Wind in Lake Michigan

Offshore Wind receives a comparable energy revenue (in unit terms) to SOO Green. Unit capacity revenue is relatively lower than other policy options due to the lower Unforced Capacity (UCAP) contribution, which is the MW value of the resource as cleared in the capacity market, ~~-~~compared to Installed Capacity (ICAP), which generally reflects the nameplate value.[108] Unit energy market impact scales similarly to other policy options.

Capacity market benefits for offshore wind are limited. PJM has identified declining UCAP expectations for renewable resources as development becomes more saturated.[109] PJM's ELCC calculations cannot be directly reproduced, but Aurora has some functionality to capture renewable resources' declining contributions to meeting peak demand. OSW averaged a 22.5% UCAP factor (as a percentage of ICAP) during the procurement period (2030-2049), which compares well with GE ELCC results (29% in 2030, 20% in 2040).

Offshore wind is an intermittent resource and has stronger output in the winter. The winter output profile does track load fairly well. The summer output profile does complement solar output as generation is lowest during the middle of the day but does not help to mitigate the loss of solar production with a strong evening ramp. Under the current RTO load forecast, Illinois (and the RTOs at large) are still summer-

[107] Total load, as forecasted by the RTOs as sourced in the inputs section, is about 144.5 GWh.

[108] See PJM Glossary https://www.pjm.com/Glossary

[109] December 2022 Effective Load Carrying Capability Report, PJM Interconnection, January 6, 2023.
elcc-report-december-2022.ashx (pjm.com)

peaking, but if electrification of building heating grows then the seasonality of offshore wind will better match the seasonality of load.

PJM's February 2024 ELCC stakeholder education materials reveal that oceanic offshore wind demonstrates an average deliverability of 27% during summer and 92% during winter, covering daytime, morning, and evening peaks.[110] This finding suggests potential benefits for Illinois, as the offshore wind complements solar output during the summer season and evening ramp. This finding supports an assertion from Union of Concerned Scientists, Environmental Defense Fund, and Sierra Club Illinois in comments on the draft Policy Study that the seasonal capacity contribution of offshore wind could be substantially higher.[111] Based on PJM's July 2023 material, offshore wind could have a winter accreditation value of 68%, which is four times greater than its projected summer values of 17%.[112] Notably though, the cohort of units included in PJM's analysis likely does not include any pilot projects in the Great Lakes and is representative of ocean-sited projects with higher overall capacity factors.

PJM has observed that winter risks predominate across all risk metrics, accounting for 54.8% for LOLE and 70.3% for Loss-of-Load Hours (LOLH), with corresponding summer risks at 45.2% and 29.7% respectively. Moreover, Expected Unserved Energy (EUE) exhibits 87.2% winter risk and 12.8% summer risk.[113] Previously, PJM indicated that roughly 64% of EUE occurred in winter, with 36% in summer, while about 65% of LOLE happened in summer, with the remaining 35% in winter.[114] These shifts in seasonal risk distribution are attributed to changes in the resource mix and the 2024 load forecast.

PJM proposed adopting the "marginal" ELCC approach, accrediting resources based on their marginal contribution to system resource adequacy within the target resource mix, rather than the "adjusted class average." FERC approved this new methodology on January 30th, 2024, under Docket No. ER24-99. At the time of the IPA study, PJM has not yet released a long-term forecast for ELCC class ratings.

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[110] PJM ELCC Education, page 14, February 16 & 21

https://www.pjm.com/-/media/committees-groups/committees/pc/2024/20240221-special/elcc-education.ashx

[111] Union of Concerned Scientists/Environmental Defense Fund/Sierra Club, February 12, 2024. See page 1.

https://ipa.illinois.gov/content/dam/soi/en/web/ipa/documents/20240213-ucs-edf-sierra-club.pdf

[112] PJM Update on Reliability Risk Modeling Presentation, July 17, 2023. See page 8.

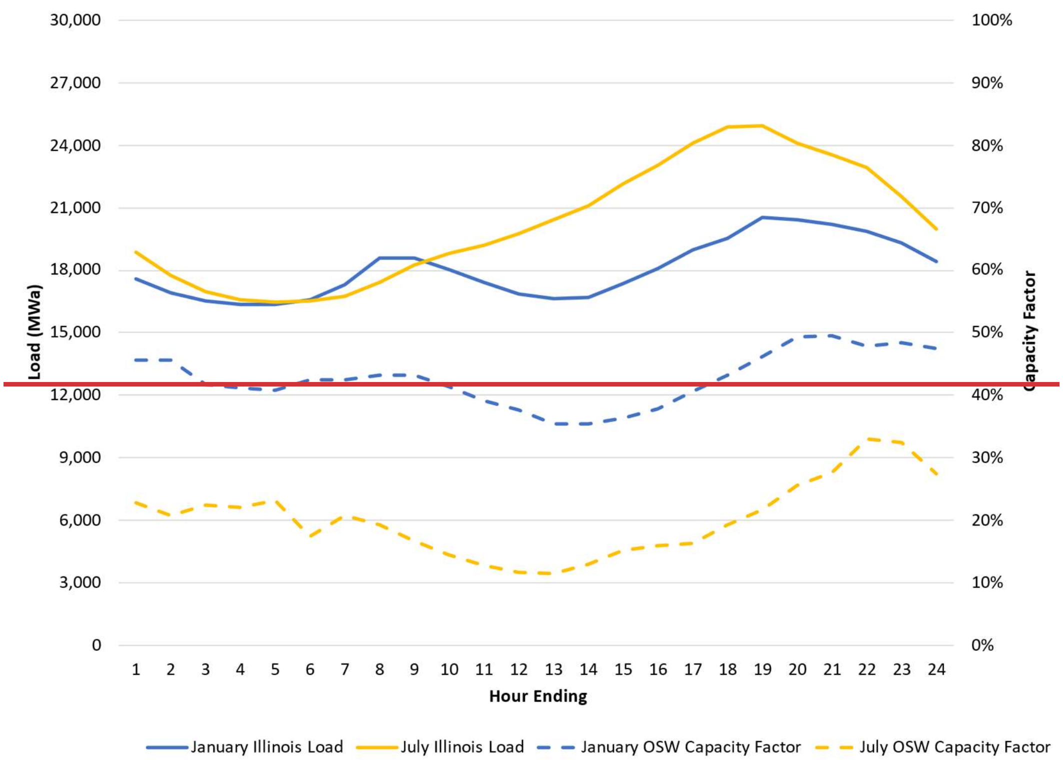
https://pjm.com/-/media/committees-groups/cifp-ra/2023/20230717/20230717-item-03---reliability-risk-modeling---july-update-v2-copy.ashx#Page=8

[113] PJM ELCC Education, February 16 & 21, 2024. See page 21,38

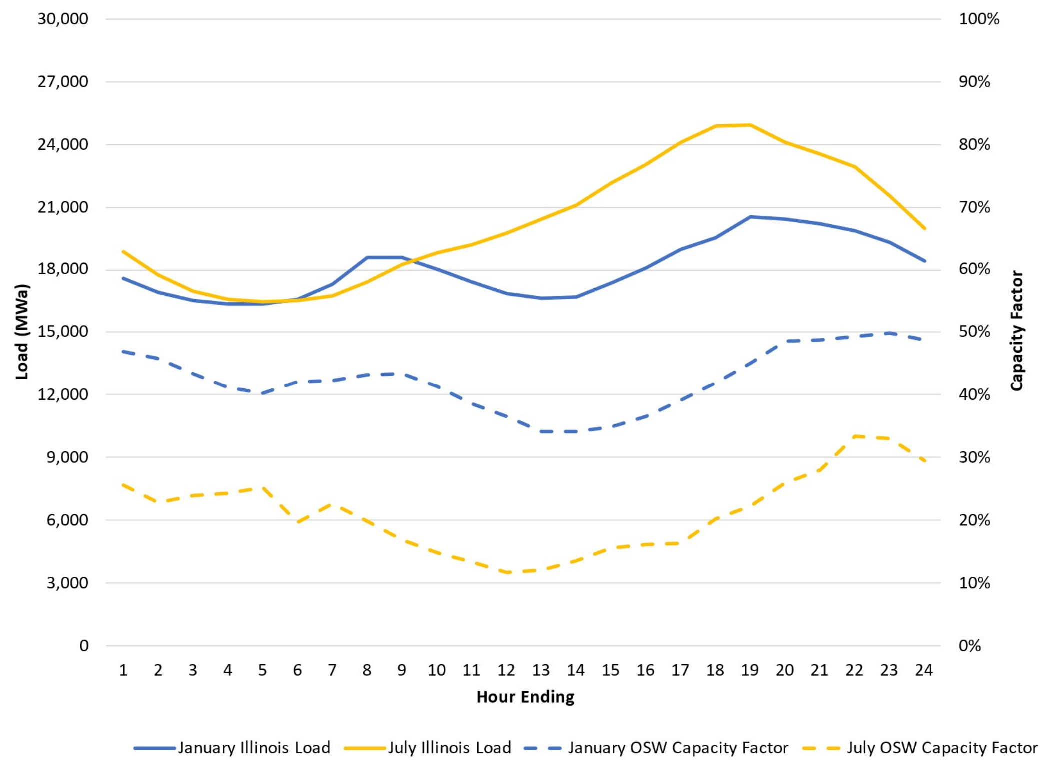
https://www.pjm.com/-/media/committees-groups/committees/pc/2024/20240221-special/elcc-education.ashx

[114] FERC Docket No. ER24-99, page 116

Figure 33~~28~~: Load and Offshore Wind Average Profiles[115]



[115] Load from 2050 averaged.



The introduction of the Offshore Wind pilot project had a small impact on the amount of ZEF output dispatched, on the order of 1% decrease. ZEF output is clustered around peak hours rather than spread across the year.

2.3.2 Energy Storage Systems Development

For energy storage systems development, energy revenue represents the revenue net the cost of charging the storage with grid power. ~~Energy~~That energy revenue effectively represents the difference between high-priced hours and low-priced hours in a given day, further dampened by efficiency losses. Therefore, energy storage systems receive ~~minimal~~less energy revenue over the 20-year period~~.~~ relative to generating resources on a $/MWh basis. Energy margins are also somewhat narrowed with the introduction of large quantities of storage, as storage charging increases prices and discharge reduces them. This dynamic is captured in the energy market impact. Energy storage systems' unit revenues and costs are calculated based on the discharge MWh of the facilities.

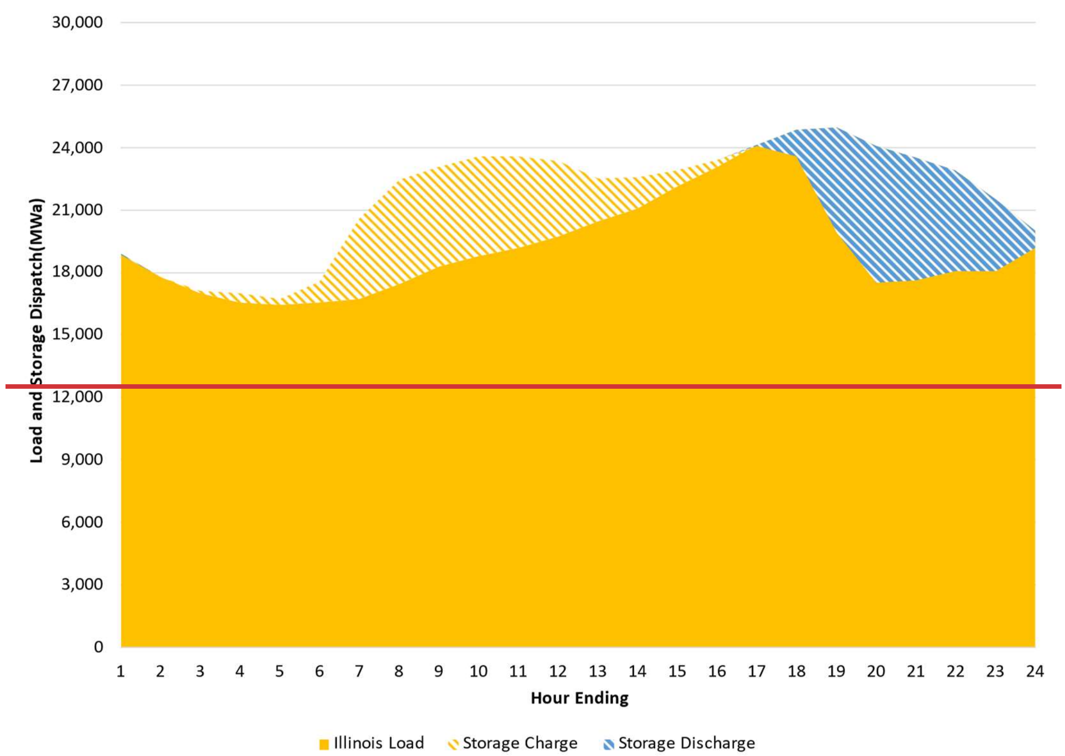
Capacity market benefits make up the lion's share of benefits for the energy storage systems proposal. Per the duration assumptions chosen, the 7,500 MW energy systems storage portfolio modeled had a weighted average UCAP factor of 82.6%. Ten-hour duration storage in each RTO was modeled at 100% UCAP, and four-hour duration storage in MISO and PJM were modeled with long-term UCAP factors of 75% and 100% respectively.[116] The energy storage systems ELCC values compare to 94% and 65% in GE's

[116] MISO UCAP factors were modeled annually using accreditation values from the Futures Refresh Assumptions Book:

ELCC modeling for 2030 and 2040, but notably GE's ELCC values were modeled based on an isolated Illinois system. The renewable resource build assumed was limited to planned capacity in the GE MARS run, but storage resources may also have the opportunity to charge from surplus power if Illinois is receiving imports. PJM's ELCC Class Ratings for the 2025/2026 BRA provide 59% and 78% class ratings for 4-hour and 10-hour storage, respectively.[117] However, no long-term forecast of Marginal ELCC given expected changes to PJM's capacity mix is presently available. With additional renewable power development, 4-hour storage ELCC may improve, as it did in PJM's previous ELCC reports.[118]

Storage is active in peak shaving and renewable balancing in the production cost modeling. During the summer storage helps to mitigate the evening peak as solar generation ramps down. During the winter, some discharging is done during the morning ramp to help mitigate the morning peak, charging occurs midday to store solar output, and then batteries discharge to mitigate the evening peak.

Figure 34~~29~~: Load and Storage Profile, July 2050



20231002 LRTP Workshop - Futures Refresh Assumptions Book630366.pdf (misoenergy.org)

PJM UCAP factors were modeled based on the December 2022 ELCC Report, which estimates 4-hour ELCC at 100% by 2030. See page 8.

[117] 2025-26-bra-elcc-class-ratings.ashx (pjm.com)

[118] PJM December 2022 Effective Load Carrying Capability (ELCC) Report, see Figure 4. 4-hour storage ELCC increased from 77% in 2025 to 100% by 2031. elcc-report-december-2022.ashx (pjm.com)

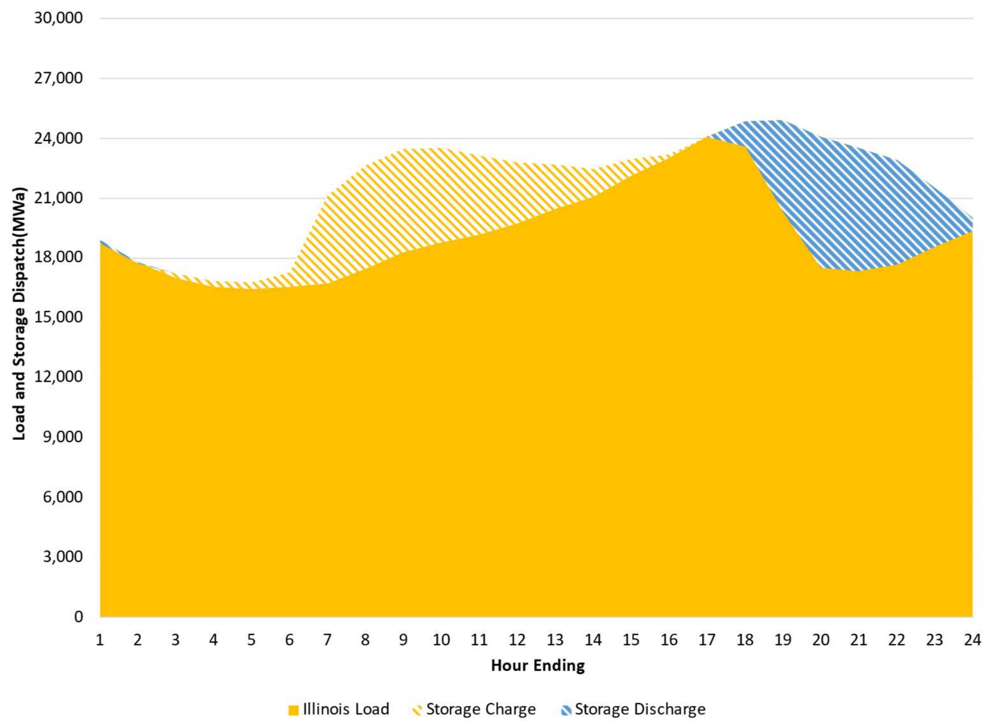
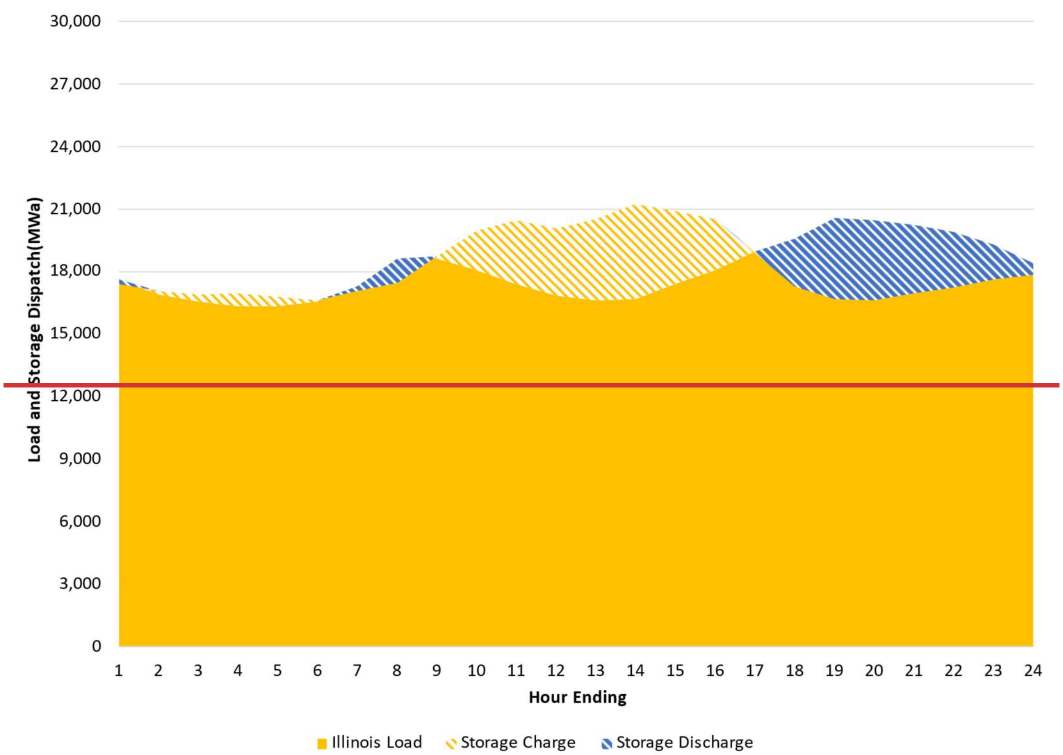
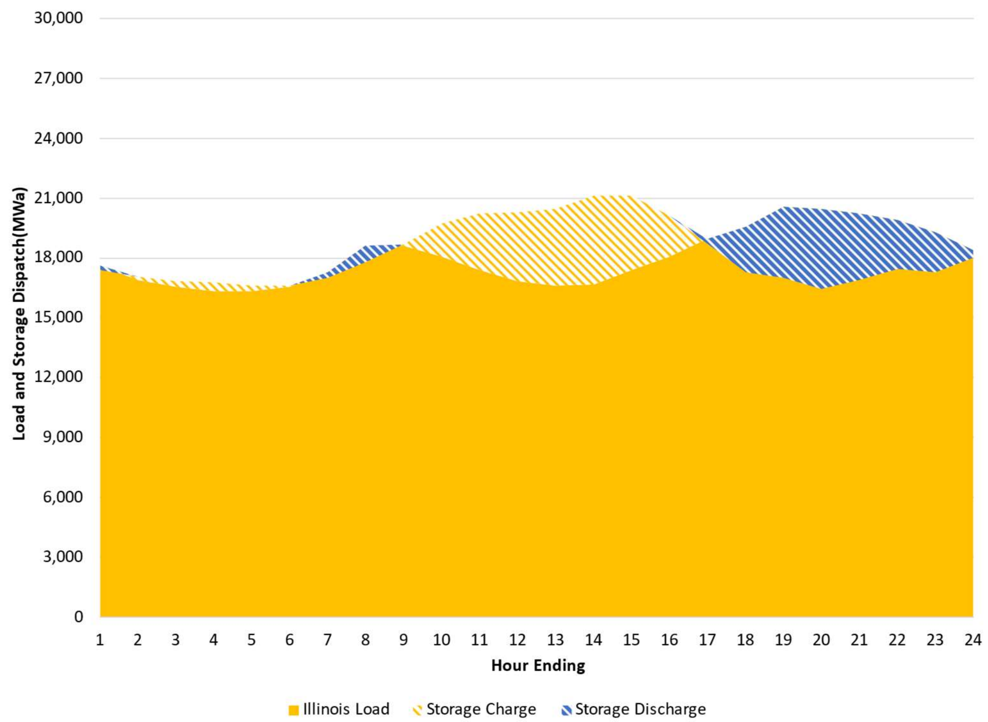


Figure ~~30~~35: Load and Storage Profile, January 2050





The introduction of storage resources had a significant impact on the dispatch of ZEFs. Storage reduced the output of ZEFs by 63%. The introduction of storage resources also effectively "idled" approximately 2,100 MW of ZEF capacity that was included in the Base case. The idled units had zero output in the second half of the study period (2040-2049) in the Storage case.

Ancillary services were not quantified in the Aurora modeling but represent additional revenue opportunities for energy storage systems. MISO and PJM generally procure ancillary services through separate products: (1) spinning reserves (2) supplemental non-spinning reserves, (3) synchronized/non-synchronized reserve services, and (4) regulation. PJM and MISO define ancillary services are those "services necessary to support the transmission of power from generators to retail customers given the obligations of control areas and transmitting utilities within those control areas to maintain reliable operations of the transmission system.[119,120] Energy storage resources do not need to deep charge or discharge to provide ancillary services, which reduces cell degradation.[121] PJM and MISO may need to procure additional quantities of traditional reserve products (reserves, regulation) in order to mitigate renewable output forecast error as more wind and solar come online.

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119 MISO, Redefining Energy and Ancillary Services Markets, December 2020. Available at https://cdn.misoenergy.org/Redefining%20Energy%20and%20Ancillary%20Services%20Markets505270.pdf

120 PJM, Ancillary Services. Available at https://www.pjm.com/-/media/about-pjm/newsroom/fact-sheets/ancillary-services-fact-sheet.ashx

121 CAISO, Special Report on Battery Storage, July 7, 2023, p. 21. Available at https://www.caiso.com/Documents/2022-Special-Report-on-Battery-Storage-Jul-7-2023.pdf

In comments on the draft Policy Study, the Energy Storage Associations requested that IPA quantify the reduction in ancillary service cost due to storage.[122] Those comments cited the all-in value of PJM ancillary services markets,[123] but several of these services are not market-based, but cost-based where generators (or PJM, in the case of control room services) are assessed on a cost of service basis. Therefore storage would have a limited impact on these costs, which are negotiated between PJM and individual generators. Ancillary services costs in PJM are shown below:

Table 9: Services Cost per MWH of Load, 2022[124]

Regulation	Scheduling, Dispatch, & System Control	Reactive	Synchronized Reserve	Total
$0.38	$0.46	$0.50	$0.12	$1.46

The Scheduling, Dispatch, and System cost category is largely made up of PJM costs and black start services, which storage is unlikely to compete for. PJM's market monitor defines black start as "… the ability of a generating unit to start without an outside electrical supply, or the demonstrated ability of a generating unit to automatically remain operating at reduced levels when disconnected from the grid (automatic load rejection or ALR)." The market monitor notes that "PJM does not have a market to provide black start service, but compensates black start resource owners on the basis of cost of service rates defined in the tariff." In 2022, ComEd was assessed about $9 million in black start charges.[125] PJM's Market Monitor notes that "Reactive capability charges are based on FERC approved filings for individual unit revenue requirements that are typically black box settlements. Reactive service charges are paid to units that operate in real time outside of their normal range at the direction of PJM for the purpose of providing reactive service." Reactive capability charges are represented about $384 million out of $385.5 million total reactive power charges in 2022.[126] However, this market is spread across 800 resources within PJM. Given that the vast majority of the Regulation is a market-based product, but the quantities sold are so small (500-800 MW) that the CONE study did not recommend that units be assumed to capture new revenue.[127] Storage may also provide reserves, which are a market-based product, but the average primary reserve MW requirement was about 3,700 MW in 2022.[128] Some of the reserve market is also cleared locationally, so ComEd zone resources cannot capture some portion of revenues or defer costs. The value of *market-based* ancillary services products to the ComEd zone, assuming that costs are

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[122] Energy Storage Associations Comments to the IPA Draft Policy Study, page 11.

[123] Monitoring Analytics, 2023 State of the Market Report for PJM, January Through June, See Table 10-4. 2023 Quarterly State of the Market Report for PJM: January through June (monitoringanalytics.com)

[124] Monitoring Analytics, 2022 State of the Market Report for PJM, See Table 10-6. 2022 State of the Market Report for PJM (monitoringanalytics.com)

[125] Monitoring Analytics, 2022 State of the Market Report for PJM, see page 610 and Table 10-71.

[126] *Id*, see page 545, Tables 10-75 and 10-78.

[127] "Regarding ancillary services, we determined that regulation revenues should not be included in the calculation because the market is too small at only 500-800 MW (some of which is already absorbed by BESS plants providing the premium RegD product)." The Brattle Group, Sargent & Lundy, PJM CONE 2026.2027 Report, page 52. PJM CONE 2026/2027 Report

[128] Monitoring Analytics, 2022 State of the Market Report for PJM, See Table 10-9.

assigned by load share similarly to the Energy Storage Associations' comments, is closer to $40 million a year, and increased storage capability will have to compete with other resources in PJM's markets.

The size of Ameren's ancillary services obligations is also overstated in the comments of the Energy Storage Associations. It appears that prices for regulation and reserves were added together, but these services are not assessed on the same quantities and therefore are not additive. MISO's 2022 State of the Market Report notes that the "all-in" price of electricity, where all products (energy, capacity, ancillary services, and uplift) are spread across demand, was only $0.16/MWh for ancillary services.[129] The true cost of ancillary services, if estimated by load share, for Ameren customers would be about $5-6 million. The current markets for ancillary services are small, though need for ancillary products may grow in the future.

MISO has also been considering the effect of the "duck curve." This phenomenon is characterized by a change in net load caused by increased large penetrations of intermittent resources (e.g., solar), where net load drops around mid-day due to the impact of renewable resources (i.e., solar) and then in the evening as the solar production decreases and electricity consumption increases. This all causes a significant need for a rapid ramp-up of production from dispatchable generation resources. MISO has indicated that energy storage and paired solar and storage resources may assist in mitigating the effects of the duck curve on system reliability by helping reduce the evening peak net load by shifting demand to off peak hours.[130] Going forward, PJM and MISO may require flexible ramping products, as CAISO has established.[131] Ramping is upward or downward control by resources over a period of time needed to maintain load-generation balance. This is most needed at times of major load shifts, especially during the winter evening ramps, when increases in load coincide with decreases in solar output and are potentially amplified by wind output changes.

2.3.3 SOO Green HVDC Line

SOO Green has a similar unit energy market revenue to the offshore wind development. The energy market impact is higher than for other policy options due to the stronger "around the clock" profile of the clean energy imports. In addition, headroom on the HVDC transmission line may be used for economic imports of system energy.

Capacity benefits of the SOO Green line were estimated based on the average clean energy flows over the HVDC transmission line during peak hours of the observed system peak for PJM. Based on this calculation, a ~~90.1~~87.3% UCAP factor was estimated for the SOO Green HVDC transmission project. Any incremental flows from "system" energy that is not secured by SOO Green as clean energy supplied to Illinois via contract is not assumed to provide capacity value. The renewable supply portfolio contracted for transport via SOO Green is not assumed to provide any residual capacity to MISO; these contracted resources would likely be required to "de-list" from the MISO market in order to become qualified as

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[129] Potomac Economics, 2022 State of the Market for the MISO Electricity Markets, June 15, 2023. See page 4. 2022 STATE OF THE MARKET REPORT (potomaceconomics.com)

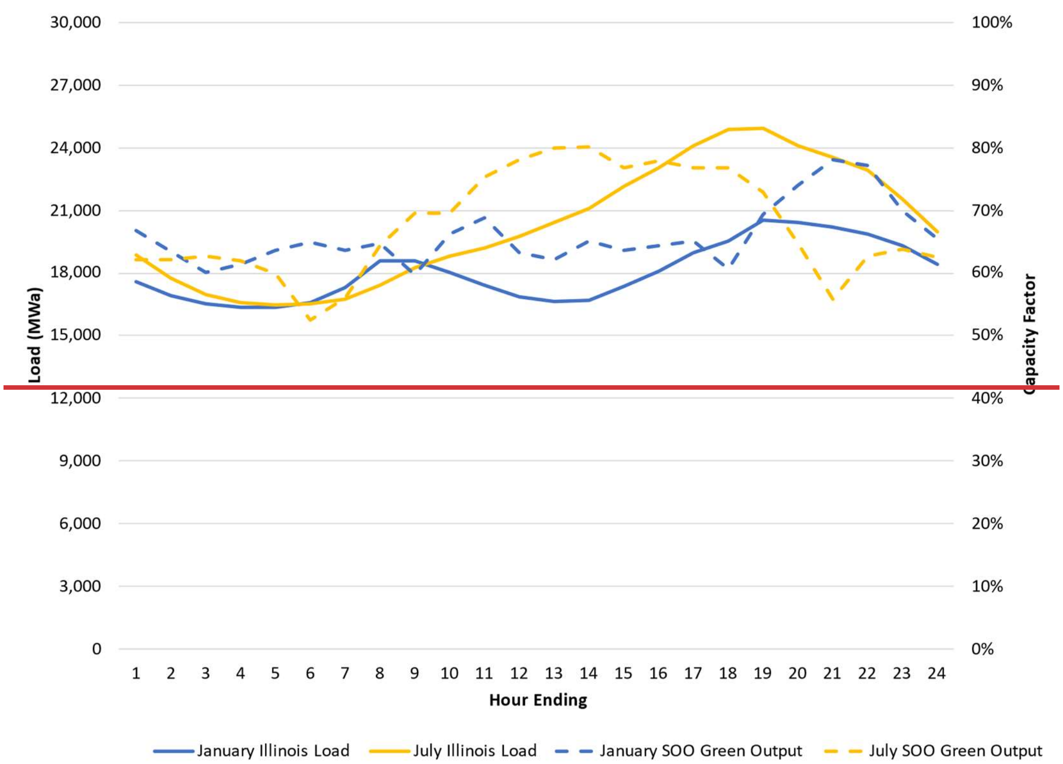
[130] MISO, 2022 Regional Resource Assessment, November 2022, p. 28-30. Available at https://cdn.misoenergy.org/2022%20Regional%20Resource%20Assessment%20Report627163.pdf

[131] CAISO 2022 Annual Report on Market Issues & Performance, July 11, 2023. See page 107. 2022-Annual-Report-on-Market-Issues-and-Performance-Jul-11-2023.pdf (caiso.com)

external resources in the PJM capacity market. This UCAP estimate is similar to GE's MARS ELCC results of 96% in 2030 and 92% in 2040. In comments on the draft Policy Study, Invenergy Transmission noted that if the combined class ratings of the clean energy portfolio were accredited per the most recently posted ELCC ratings PJM has posted, the total accredited capacity would be 1,589 MW, or 76%.[132] The modeling team notes that SOO Green would not be placed into service in time for the 2025/2026 BRA, and that PJM has not yet released a long-term load forecast under the new Marginal ELCC methodology.

SOO Green has a ~~consistently~~relatively high capacity factor (about ~~72~~70% over the study period) due to the "overbuild" of renewable supply needed to energize the HVDC line, as well as the storage resource that helps to bank surplus energy for later delivery over the line. The influence of solar on high delivery volumes can be seen in the summer delivery profile. The facility essentially performs as a baseload or efficient intermediate level generator for the ComEd zone.

Figure 36~~31~~: Illinois Load and SOO Green Output Profiles, 2050



[132] Invenergy Transmission Response to IPA Draft Policy Study, page 9. 20240213-invenergy-transmission.pdf (illinois.gov)

The introduction of SOO Green had a significant impact on the dispatch of ZEFs. SOO Green reduced the output of ZEFs by 29%. The introduction of SOO Green also effectively "idled" approximately 700 MW of ZEF capacity that was included in the Base case.

In order to capture the 25-year contract term identified in P.A. 103-0580, costs, revenue offsets, and energy market impacts were extrapolated to cover the remaining 5-year period (2050-2054). The strike price is in nominal level terms, consistent with the CPNY contract, so no growth was applied. The energy revenue was extrapolated based on the average growth rate over 2045-2049. Capacity revenue was expected to grow at the rate of CONE escalation (3.5%). Energy market impacts were conservatively extrapolated in the same manner as energy revenue but given that market impacts are greater after retirement of the fossil fleet, the additional energy market impacts estimated are substantial. Clean flows over the line were assumed to be the five-year average across 2045-2049.

Table 10: SOO Green Summary Projections, 2030-2054 Contract Period

Case	*Costs*	*Energy Revenue*	*Capacity Revenue*	*Net Market Revenues*	*Energy Market Impact*	*Total*	*Energy Output*
				$1,000 Nominal			**GWh**
($1,000 Nominal)	37,025,252	12,800,308	11,105,160	-$13,119,784	9,268,046	-3,851,737	320,866
($1,000 2022) - Annualized	907,502	301,753	250,918	-$354,831	206,814	-148,017	12,835

2.3.4 All Policies Adopted

The unit benefits of the All Policies case are driven by the energy storage systems and SOO Green impacts, given the relatively small size of the offshore wind project in relation to these projects. The energy storage systems and SOO Green projects deliver similar amounts of energy, so the relative size of each benefit category reflects this balance.

The UCAP contribution for the combined portfolio of offshore wind, energy storage systems, and the SOO Green project totals 8,~~094~~070 MW, or 82.~~6~~3% of nameplate offshore wind, Illinois energy storage systems, and SOO Green HVDC transmission capacity. The calculated UCAP contribution for the SOO Green project ~~drops to 88.4~~remains at 87.3% in the All Policies case~~ due to slightly less flow over the line during peak conditions, in part due to the other~~.

The introduction of all policy resources ~~being available to meet peak~~had a significant impact on the dispatch of ZEFs. ZEF output was reduced by 76%. The introduction of all policy resources also effectively "idled" approximately 2,200 MW of ZEF capacity that was included in the Base Case.

2.3.5 Distributed Scale Paired Storage Sensitivity

The distributed scale paired storage sensitivity was not run through production cost modeling. However, to provide a sense of expected costs, revenues, and benefits, the modeling team scaled modeling results from the Storage case to provide a first-cut estimate. The scaled results from the Storage case, combined with the Residential and Commercial Storage cost data (briefly discussed above), are summarized below in Table 11~~Table 4.~~.

Table 11: Distributed Project Annualized ($2022) Summary

Description	*Costs*	*Energy Revenue*	*Capacity Revenue*	*Net Market Revenues*	*Energy Market Impact*	*Total*
Storage ($1,000 2022)	$253,129	$13	$94,471	-$158,645	$4,335	-$154,310
Storage ($2022/MWh)	$10.13	$0.00	$3.78	-$6.35	$0.17	-$6.17

Description	*Costs*	*Energy Revenue*	*Capacity Revenue*	*Net Market Revenues*	*Energy Market Impact*	*Total*
Storage ($1,000 2022)	$197,891	$15,141	$100,567	-$82,182	$4,057	-$78,125
Storage ($2022/MWh)	$8.00	$0.61	$4.06	-$3.32	$0.16	-$3.16

2.4 Estimated Bill Impacts

In response to a recommendation on the draft Policy Study made by Vistra,[133] the modeling team conducted an additional analysis to estimate the bill impact for the average residential Ameren or ComEd customer of the policies studied. The bill impacts were estimated by unitizing net costs (costs net market

[133] Vistra Corp.'s Comments on Illinois Power Agency's Draft 2024 Policy Study, see page 5.
20240213-vistra-corp.pdf (illinois.gov)

revenues) across retail load, as found in Appendix B of the filed 2024 Long-Term Renewable Resources Procurement Plan.[134] The unitized cost is then multiplied by the current average annual residential usage of Ameren and ComEd customers, which are 11,355 kWh and 7,302 kWh, respectively.[135] The "Net Market Revenues" bill impacts represent the cost to the consumer to support the given policy.

Table 12: Average Monthly Residential Bill Impact (2030-2049)

Bill Impact (2030 - 2049)	Offshore Wind	Energy Storage	HVDC
Ameren (Real 2022 dollars)	$0.25	$1.89	$3.42
Ameren (Nominal dollars)	$0.39	$2.88	$4.99
ComEd (Real 2022 dollars)	$0.16	$1.21	$2.20
ComEd (Nominal dollars)	$0.25	$1.85	$3.21

~~2.4~~2.5 Conclusions

Aurora production cost modeling results show that market energy and capacity revenues fall short of the costs of the policy proposals. Thus, each of these policy projects individually, as well as if all three were to be operated together, would result in higher electricity costs for Illinois. The net difference between the annualized costs, offsets, and energy market benefit would result in net costs which would be reflected in higher electricity rates in the state. Under the costs and revenues contemplated, SOO Green would result in net annual costs of $~~337~~252 million while the storage proposal would result in net annual costs of $~~356~~216 million. The OSW system would result in net annual costs of $~~43~~23 million. In terms of impacts on the Illinois power market, the state's clean energy policies, and electricity costs, the storage initiative offers the greatest benefits, slightly greater than SOO Green, but also has the highest costs. Offshore wind has ~~the highest cost on a $/MWh of energy output but~~ the lowest net annual cost, which is reasonable given the relatively small scale of the project size ~~and substantial uncertainty over development in the Great Lakes.~~. Only the offshore wind subsidy value has been capped in the legislature's directions to the IPA; this analysis shows that the proposed subsidy value ~~is unlikely to~~will not quite ~~lead to~~fully support a commercialized pilot project at the costs and revenues projected.

[134] See sheet "Collections and ACP". Retail load is assumed to stay constant following the last reported year.

https://ipa.illinois.gov/content/dam/soi/en/web/ipa/documents/appendix-b-20-oct-2023-11am.xlsx

[135] Illinois Commerce Commission, Illinois Electric Utilities Comparison of Electric Sales Statistics For Calendar Years 2022 and 2021, page 8. 22-21 Comparison of Electric Sales Statistics-.pdf (illinois.gov)

Table 13 - Project Annualized ($1,000 2022) Summary

Case	*Costs*	*Energy Revenue*	*Capacity Revenue*	*Net Market Revenues*	*Energy Market Impact*	*Total*
OSW	$54,923	$17,618	$5,739	-$31,565	$8,875	-$22,690
Storage	$1,050,160	$96,276	$714,742	-$239,142	$22,616	-$216,525
SOO Green	$960,437	$295,990	$233,739	-$430,708	$178,305	-$252,403
All	$2,065,520	$411,169	$954,221	-$700,130	$188,490	-$511,640

Case	*Costs*	*Energy Revenue*	*Capacity Revenue*	*Net Market Revenues*	*Energy Market Impact*	*Total*
~~OSW~~	~~$68,518~~	~~$16,799~~	~~$5,229~~	~~$46,490~~	~~$3,704~~	~~$42,786~~
Storage	$1,050,160	$83	$669,025	-$381,052	$25,450	-$355,602
SOO Green	$988,425	$342,697	$214,476	-$431,253	$93,896	-$337,356
All	$2,664,275	$306,547	$884,643	-$1,473,085	$76,566	-$1,396,519

While reflecting increased costs of electricity, each policy initiative would offer significant environmental benefits in terms of reductions in the emissions of CO2~~, SO2, NOx and PM2.5~~ than would occur if these initiatives were not implemented. When considering electric system wide operations (including other states in PJM and MISO), SOO Green has the greatest impact with estimated 20-year CO2 of ~~145~~153 million tons followed by the storage reductions of ~~30~~27 million tons and the OSW project with ~~8~~7 million tons. In Illinois, SOO Green would reduce SO2 emissions by ~~39~~8 thousand tons, NOx emissions by ~~64~~6 thousand tons and PM2.5 emissions by ~~2~~one thousand tons. The storage initiative would reduce SO2 emissions by ~~12~~8 thousand tons, NOx emissions by ~~29~~15 thousand tons and PM2.5 emissions by ~~800~~700 tons. The OSW project ~~would have a much smaller~~ results in a small increase~~impact on~~ in in-state SO2 and NOx emissions of about 100 tons each. PM2.5 emissions are reduced by 21 tons.~~ with reductions of SO2 emissions by 1 thousand tons, NOX by 600 tons and PM2.5 of 47 tons~~.

The electricity cost impacts reflect the status of technology and markets based on currently available information and assumptions. Capital and operating costs may decline more rapidly than the Conservative case assumed in the ATB. The recent cost pressures resulting from inflation and the supply chain issues plaguing renewable power sources which have led to increased costs and many renewable project cancellations are likely to abate. Wholesale power market rules and federal policy may also shift the relative costs and benefits of the policy proposals. Interconnection costs, subject to changing Federal and ISO regulations and policies, also represent a source of uncertainty. Interest rates represent another source of uncertainty that affects financing costs. Storage costs may also be reduced by pairing the facilities with renewable generation to receive the ITC, though these projects may have reduced operational benefits due to restrictions on grid charging necessary to obtain the credit. Deeper decarbonization of other economic sectors would increase load and could put upward pressure on market prices.

The production cost modeling only considers a portion of the benefits of the policy proposals. Reductions in carbon emissions may reduce long-term damages due to climate change, and reductions in other criteria pollutants benefit Illinois and its neighbors through better health outcomes. The clean energy investments made also have indirect and induced economic benefits associated with local spending, which are captured in IMPLAN modeling.