2025

ILLINOIS POWER AGENCY

ELECTRICITY PROCUREMENT PLAN

2025 Plan

Filed for Illinois Commerce Commission Approval

September 30, 2024

Prepared in accordance with the Illinois Power Agency Act (20 ILCS 3855) and the Illinois Public Utilities Act (220 ILCS 5)

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Appendices are available separately at https://ipa.illinois.gov/energy-procurement/2025-appendices.html

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1 Executive Summary

This is the seventeenth electricity procurement plan (the "Plan," "Procurement Plan," "2025 Plan," or "2025 Procurement Plan") prepared by the Illinois Power Agency ("IPA" or "Agency") under the authority granted to it under the Illinois Power Agency Act ("IPA Act") and the Illinois Public Utilities Act ("PUA"). Chapter 2 of this Plan describes the specific legislative authority and requirements to be included in the plan, including those set forth in previous orders of the Illinois Commerce Commission ("Commission" or "ICC").

The Plan addresses the provision of electricity for the "eligible retail customers" of Ameren Illinois Company ("Ameren Illinois"), Commonwealth Edison Company ("ComEd"), and MidAmerican Energy Company ("MidAmerican"). Following MidAmerican's participation for its ninth time in the 2024 IPA Procurement Plan, MidAmerican has again elected to have the IPA procure power and energy for a portion of its eligible Illinois customers through the 2025 Plan.[1]

As defined in Section 16-111.5(a) of the PUA, "eligible retail customers" are for Ameren Illinois and ComEd generally residential and small commercial fixed price customers who have not chosen service from an alternate supplier. For MidAmerican, eligible retail customers include residential, commercial, industrial, street lighting, and public authority customers that purchase power and energy from MidAmerican under fixed-price bundled service tariffs. The Plan considers a 5-year planning horizon that begins with the 2025-2026 Delivery Year[2] and lasts through the 2029-2030 Delivery Year.

The 2024 Procurement Plan, as approved by the Commission in Docket No. 23-0665, called for the energy requirements for Ameren Illinois, ComEd, and MidAmerican to be procured by the IPA through two block energy procurements (Spring 2024 and Fall 2024). In addition, the 2024 Plan included two capacity procurements for Ameren Illinois (Spring 2024 and Fall 2024).

This Plan proposes to continue the approach first approved by the Commission in the 2023 Plan which recognizes the offsetting price impacts for ComEd's eligible retail customers created by ComEd's Carbon Mitigation Credit ("CMC") contracts, which run through the end of the 2026-2027 Delivery Year, with a modification for the non-summer period (the delivery months of October through May). Under this approach, the IPA hedges 50% of ComEd's forecasted eligible retail customer load during the summer delivery months and 30% during the non-summer delivery months. The price volatility of the remaining load is offset by month to month changes in the CMC price.[3] As this Plan addresses the procurement of electricity through the 2027-2028 Delivery Year, this Plan includes a ramping up of procurement volumes in anticipation of returning to hedging 100% of ComEd's forecasted eligible retail customer load starting in the 2027-2028 Delivery Year.

In the draft Plan released for stakeholder feedback on August 15, 2024, the Agency sought feedback on (1) adding a financial swap contract option to Ameren Illinois capacity procurements and (2) whether the IPA should consider hedging capacity for ComEd in light of recent PJM capacity price volatility. For this 2025 Plan filed for ICC approval, the Agency proposes several changes to prior strategies related to capacity hedging for Ameren Illinois, including adding an annual capacity product and a financial swap contract option (see Section 5.2.2.6). The Agency does not propose any capacity procurement for ComEd at this time, but rather will continue to monitor the PJM capacity market and any potential regulatory or statutory reforms (see Section 5.2.1.1).

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[1] While procurement plans are required to be prepared annually for Ameren Illinois and ComEd, Section 16-111.5(a) of the PUA states that "[a] small multi-jurisdictional electric utility . . . may elect to procure power and energy for all or a portion of its eligible Illinois retail customers" in accordance with the planning and procurement provisions found in the IPA Act. On April 9, 2015, MidAmerican formally notified the IPA of its intent to procure power and energy for a portion of its eligible retail customer load through the IPA for the first time and to participate in its 2016 procurement planning process. This Plan reflects the continued inclusion of MidAmerican in the IPA's 2025 procurement planning process.

[2] As defined by Section 1-10 of the IPA Act, a delivery year lasts from June 1 until May 31 of the following year. (20 ILCS 3855/1-10).

[3] See Section 6.9 of this Plan for more information.

1.1 Power Procurement Strategy

The 2025 Plan will continue using the risk management and procurement strategy that the IPA has historically utilized: hedging load by procuring on and off-peak blocks of forward energy in a three-year laddered approach. The IPA believes the continuation of its tested and proven risk management strategy is the most prudent and reasonable approach, and the approach most likely to meet its statutorily mandated objective to "[d]evelop electricity procurement plans to ensure adequate, reliable, affordable, efficient, and environmentally sustainable electric service at the lowest total cost over time, taking into account any benefits of price stability."[4]

- The IPA's energy hedging strategy for the 2025 Procurement Plan is largely consistent with the strategy used for the 2024 Plan as approved by the Commission in ICC Docket No. 23-0665.[5] That strategy involves the procurement of hedges in 2025 to meet a portion of anticipated eligible retail customer energy supply requirements for a three-year period and includes two block energy procurement events, the first in the Spring and the second in the Fall, with a partially open position for ComEd through the 2026-2027 delivery year in light of CMC contracts.
- As explained in more detail in Section 5.2.2.1, MISO has implemented a seasonal resource adequacy construct starting with the 2023-2024 Delivery Year. Under the seasonal resource adequacy construct, capacity in the MISO Planning Resource Auction ("PRA")[6] and in the IPA's bilateral procurements is now procured for each of the four distinct seasons: summer, fall, winter, and spring.[7]

For the 2026-2027 and 2027-2028 Delivery Years, the IPA will continue the strategy of procuring a portion of Ameren Illinois' forecasted capacity requirements in bilateral transactions and the remaining balance through the MISO Planning Resource Auction ("PRA"). As also explained in more detail in Sections 5.2.2.7 and 7.2.1.2, the IPA will continue with its strategy of procuring up to 75% of its forecasted capacity requirements in its bilateral procurements. For the 2026-2027 Delivery Year, the IPA recommends procuring up to 50% of its forecasted capacity requirements in bilateral transactions in Spring 2025 and up to 75% in Fall 2025, with the balance of the forecast capacity requirement to be procured in the 2026 MISO PRA. For the 2027-2028 Delivery Year, the IPA will procure up to 12.5% of its forecasted capacity requirements in bilateral transactions in Spring 2025 and up to 25% in Fall 2025, with the balance of the forecast capacity requirement to be determined in the 2026 Electricity Procurement Plan. Based upon feedback received on the draft 2025 Plan, the Agency proposes to add an option for a financial capacity swap contract product to its procurements, but not to add an additional procurement. See Section 5.2.2.6 for more information.

For ComEd, consistent with the strategy adopted in prior plans, capacity requirements will be secured by ComEd through the PJM Reliability Pricing Model ("RPM") process. While the Agency sought stakeholder feedback on to hedge capacity for ComEd in the draft 2025 Plan, the Agency does not propose to do so under this filed Plan. See Section 5.2.1.1 for more information.

Following the approach taken in the 2024 Plan, the MidAmerican's forecasted capacity deficit will be secured by MidAmerican through the annual MISO PRA.[8]

In addition to the various approaches described above, ancillary services, load balancing services, and transmission services will be purchased by Ameren Illinois and MidAmerican from the MISO marketplace and by ComEd from the PJM markets.

The following tables summarize the IPA's 2025 hedging strategy and planned procurements:

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[4] 20 ILCS 3855/1-20(a)(1).

[5] See Final Order, ICC Docket No. 23-0665 (Dec. 14, 2023).

[6] The PRA is an annual capacity auction that determines clearing prices on a zonal basis. The PRA provides load serving entities in MISO with an option for meeting their capacity obligations by buying capacity from the auction.

[7] Summer will cover the months of June to August, Fall will cover the months of September to November, Winter will cover the months of December to February, and Spring will cover the months of March to May.

[8] MidAmerican utilizes the IPA's procurement process to meet only that portion of its requirements not under existing contracts (or allocated to its Illinois service territory).

Table 1-1: Summary of Energy Hedging Strategy for Ameren Illinois and MidAmerican[9]

Spring 2025 Procurement			Fall 2025 Procurement		
June 2025-2026 (Upcoming Delivery Year)	**Upcoming Delivery Year+1**	**Upcoming Delivery Year+2**	**October 2025-May 2026**	**Upcoming Delivery Year + 1**	**Upcoming Delivery Year + 2**
June 100% on-peak and off-peak July and Aug. 106% on-peak, 100% off-peak Sep. 100% on-peak and off-peak Oct. - May 75% on-peak and off-peak	37.5% all months, except June, July and August on-peak and off-peak, which should be 52.5%.	12.5% all months except June, July and August on-peak and off-peak which should be 15%.	100% all months	50% all months, except June, July and August on-peak and off-peak, which should be 75%.	25% all months except June, July and August on-peak and off-peak which should be 30%.

Table 1-2: Summary of Energy Procurement for ComEd[10]

Spring 2025 Procurement			Fall 2025 Procurement		
June 2025-May 2026 (Upcoming Delivery Year)	Upcoming Delivery Year+1	Upcoming Delivery Year+2	October 2025-May 2026	Upcoming Delivery Year + 1	Upcoming Delivery Year + 2
June - Sep. 50% on-peak and off-peak, Oct. - May 22.5% on-peak and off-peak	11.25% all months, except June, July August, and September on-peak and off-peak, which should be 26.25%.	12.5% all months except June, July August, and September on-peak and off-peak which should be 15%.	30% all months	15% all months, except June, July August, and September on-peak and off-peak, which should be 37.5%.	25% all months except June, July August, and September on-peak and off-peak which should be 30%.

[9] Table 1-1 shows the cumulative percentage of targeted load to be hedged by the conclusion of the indicated procurement events. Any shortfalls from prior procurement events would be added to the targets for each procurement event to meet the applicable cumulative percentage.

[10] Table 1-2 shows the cumulative percentage of targeted load to be hedged by the conclusion of the indicated procurement events. Any shortfalls from prior procurement events would be added to the targets for each procurement event to meet the applicable cumulative percentage.

Table 1-3: Summary of Capacity Procurement for Ameren Illinois[11, 12]

June 2025-May 2026	June 2026-May 2027	June 2027-2028
12.5% in Spring 2023 25% in Fall 2023 50% in Spring 2024 75% in Fall 2024 100%, MISO PRA	12.5% in Spring 2024 25% in Fall 2024 50% in Spring 2025 75% in Fall 2025 100%, MISO PRA	12.5% in Spring 2025 25% in Fall 2025 Remainder to be determined in 2025 Plan.

Table 1-4: Summary of Capacity Procurement for ComEd

June 2025-May 2026	June 2026-May 2027	June 2027-May 2028	June 2028-May 2029
100% PJM RPM Auctions	100% PJM RPM Auctions	100% PJM RPM Auctions	100% PJM RPM Auctions

Table 1-5: Summary of Capacity Procurement for MidAmerican

June 2025-2026 (Upcoming Delivery Year)	June 2026-2027	June 2027-2028
100% of expected deficit through MISO PRA	100% of expected deficit through MISO PRA	100% of expected deficit through MISO PRA

1.2 Renewable Energy Resources

Through the passage of Public Act 99-0906, "the Agency shall no longer include the procurement of renewable energy resources in the annual procurement plans" and "shall instead develop a long-term renewable resources procurement plan."[13] Thus, the procurement of renewable energy resources is included in the IPA's Long-Term Renewable Resources Procurement Plan ("Long-Term Plan") rather than this Plan. The IPA's Initial Long-Term Plan was approved by the Commission in April of 2018, and its First Revised Plan was approved in February of 2020. Consistent with the enactment of Public Act 102-0662, the Agency's 2022 Long-Term Plan was filed with the Commission on March 21, 2022, and approved with modification on July 14, 2022.[14] Subsequently, the Agency sought reopening of the 2022 Long-Term Plan to address the potential expansion of Equity Eligible Contractor category capacity in the Adjustable Block Program. That process culminated in the ICC issuing a Final Order modifying the 2022 Long-Term Plan on May 4, 2023, and the Agency released a Modified 2022 Long-Term Plan on May 9, 2023. The Agency released its Draft 2024 Long-Term Plan for public comment on August 15, 2023, and filed that plan with the Commission for approval on October 20, 2023. The 2024 Long-Term Plan was approved by the ICC on February 20, 2024, and a Final Plan reflecting the Commission's Final Order was published on April 19, 2024.

[11] Table 1-2 shows the cumulative up-to percentage of capacity targeted to be procured by the conclusion of the indicated procurement event. Any shortfalls from prior procurement events would be added to the targets for each procurement event to meet the applicable cumulative percentage.

[12] Procurement percentage targets for the 2025-2026 and 2026-2027 Delivery Years from procurements conducted in 2024 were approved under the 2024 Procurement Plan. Actual procurement volumes may not match percentage targets.

[13] 20 ILCS 3855/1-75(a).

[14] See Final Order, ICC Docket No. 22-0231 (Jul. 14, 2022).

1.3 Procurement Recommendations

Table 1-6 summarizes the IPA's recommendations as described in this Plan.

Table 1-6: Summary of Procurement Plan Recommendations Based on July 15, 2024 Utility Load Forecasts (Quantities to be Adjusted Based on the March and July 2025 Load Forecasts)

	Delivery Year	Energy	Capacity [15] [16]	Transmission and Ancillary Services
Ameren Illinois	2025-2026	Up to 450 MW forecasted requirement (Spring Procurement) Up to 250 MW additional forecasted requirement (Fall Procurement)	Up to 12.5% in Spring 2023 Up to 25% in Fall 2023 Up to 50% in Spring 2024 Up to 75% in Fall 2024 Remaining balance from MISO PRA	Will be purchased from MISO
	2026-2027	Up to 200 MW forecasted requirement (Spring Procurement) Up to 225 MW additional forecasted requirement (Fall Procurement)	Up to 12.5% in Spring 2024 Up to 25% in Fall 2024 Up to 50% in Spring 2025 Up to 75% in Fall 2025 Remaining Balance from MISO PRA	Will be purchased from MISO
	2027-2028	Up to 100 MW forecasted requirement (Spring Procurement) Up to 150MW additional forecasted requirement (Fall Procurement)	Up to 12.5% in Spring 2025 Up to 25% in Fall 2025[17] Remaining balance to be determined in 2025 Plan	Will be purchased from MISO
	2028-2029	No energy procurement required	No further action at this time	Will be purchased from MISO
	2029-2030	No energy procurement required	No further action at this time.	Will be purchased from MISO
ComEd	2025-2026	Up to 700 MW forecasted requirement (Spring Procurement) Up to 175 MW additional forecasted requirement (Fall Procurement)	100% PJM RPM Auctions	Will be purchased from PJM
	2026-2027	Up to 475 MW forecasted requirement (Spring Procurement) Up to 450 MW additional forecasted requirement (Fall Procurement)	100% PJM RPM Auctions	Will be purchased from PJM
	2027-2028	Up to 575 MW forecasted requirement (Spring Procurement) Up to 575 MW additional forecasted requirement (Fall Procurement)	100% PJM RPM Auctions	Will be purchased from PJM
	2028-2029	No energy procurement required	100% PJM RPM Auctions	Will be purchased from PJM
	2029-2030	No energy procurement required	No further action at this time	Will be purchased from PJM
MidAmerican	2025-2026	Up to 50 MW forecasted requirement (Spring Procurement) No additional energy procurement needed (Fall Procurement)	100% of deficit from MISO PRA	Will be purchased from MISO
	2026-2027	No energy procurement needed (Spring Procurement) No additional energy procurement needed (Fall Procurement)	100% of deficit from MISO PRA	Will be purchased from MISO
	2027-2028	No energy procurement required	100% of expected deficit from MISO PRA	Will be purchased from MISO
	2028-2029	No energy procurement required	No further action at this time	Will be purchased from MISO
	2029-2030	No energy procurement required	No further action at this time	Will be purchased from MISO

[15] Cumulative percentage of capacity targeted to be procured by the conclusion of the indicated procurement event.

[16] Procurement percentage targets for the 2025-2026 Delivery Year conducted in 2023 were approved under the 2023 Electricity Procurement Plan. Procurement percentage targets for the 2025-2026 and 2026-2027 Delivery Years conducted in 2024 were approved under the 2024 Electricity Procurement Plan. Actual procurement volumes may not match percentage targets.

[17] Additional Procurements for the 2027-2028 Delivery Year will be considered in the 2025 Procurement Plan.

1.4 The Action Plan

In this Plan, the IPA recommended the following items for ICC approval:

1. Approve the base case load forecasts of ComEd, Ameren Illinois, and MidAmerican as submitted in July 2024.
2. Approve two energy procurement events scheduled for Spring 2025 and Fall 2025. The energy amounts to be procured in the spring will be based on updated March 17, 2025 base case load forecasts developed by Ameren Illinois, MidAmerican, and ComEd, in accordance with the hedging levels stated in this Plan, and as ultimately approved by the ICC. The energy amounts to be procured in the fall will be based on the July 15, 2025 base case load forecasts developed by Ameren Illinois, MidAmerican, and ComEd, in accordance with the hedging levels stated in this Plan, and as ultimately approved by the ICC. In the event of default on Carbon Mitigation Credit contracts, the IPA may change the hedging percentages for ComEd to mirror those of Ameren Illinois and MidAmerican, with the consensus of the IPA, ICC Staff, and the Procurement Monitor.
3. Approve two capacity procurement events for Ameren Illinois scheduled for Spring 2025 and Fall 2025. These events will procure both Zonal Resource Credits and financial swap contracts. The capacity target for the Spring 2025 procurement will be based on the updated March 17, 2025 base case load forecast developed by Ameren Illinois in accordance with the hedging levels stated in this Plan, and as ultimately approved by the ICC. The capacity target for the Fall 2025 procurement will be based on the July 15, 2025 base case load forecast developed by Ameren Illinois, in accordance with the hedging levels stated in this Plan, and as ultimately approved by the ICC.
4. The March 17, 2025, and the July 15, 2025 load forecast updates provided by the utilities to be used to implement this Plan will be pre-approved by the ICC as part of the approval of this Plan, subject to the review and consensus of the IPA, ICC Staff, the Procurement Monitor, and the applicable utility. To allow for the filing of forecast updates, a utility which has not intervened in this Plan's approval docket will be allowed to make an informational filing for forecast updates with the ICC. In the event that the parties do not reach consensus (or reach consensus that the updated load forecast should not be used) on an updated load forecast required in Items 2 and 3 above, then the most recent consensus load forecast will be used for the applicable procurement event. If those parties are unable to reach consensus on either of the updated load forecasts required in Items 2 and 3 above, then the July 2024 load forecast will be used for the applicable procurement event.
5. Approve procurement by ComEd, Ameren Illinois, and MidAmerican of capacity, network transmission service and ancillary services from each utility's respective Regional Transmission Organization ("RTO").

The Illinois Power Agency respectfully files its 2025 Procurement Plan, which the IPA believes is compliant with all applicable laws and will produce procurement results with the "lowest total costs over time, taking into account any benefit of price availability," for Commission approval and requests approval of the specific action items listed above.

2 Legislative/Regulatory Requirements of the Plan

This Section of the 2025 Procurement Plan describes the legislative and regulatory requirements applicable to the Agency's annual Procurement Plan, including compliance with previous Commission Orders. The Statutory Compliance Index (Appendix A) provides a complete cross-index of regulatory/legislative requirements and the specific sections of this Plan that address each requirement identified.

As explained above in Section 1.2, the 2025 Procurement Plan is focused only on the procurement of standard wholesale power products to meet the needs of the eligible retail customers of Ameren Illinois, ComEd, and MidAmerican.

2.1 IPA Authority

The IPA was established in 2007 by Public Act 95-0481 to ensure that ratepayers, specifically customers in service classes that have not been declared competitive and who take service from the utility's bundled rate ("eligible retail customers"),[18] benefit from retail and wholesale competition. The original objective of the IPA Act was to improve the process to procure electricity for those customers.[19] In creating the IPA, the General Assembly found that Illinois citizens should be provided "adequate, reliable, affordable, efficient, and environmentally-sustainable electric service at the lowest total cost over time, taking into account benefits of price stability."[20] The IPA Act thus directs the IPA to "[d]evelop electricity procurement plans" and conduct competitive procurement processes to bring resources under contract in a manner consistent with those findings.

Each year, the IPA thus must develop a "power procurement plan" and conduct a competitive procurement process to procure supply resources as identified in its procurement plan as approved by the Commission pursuant to Section 16-111.5 of the PUA.[21] The purpose of the power procurement plan is to secure the wholesale electric power products and associated transmission services to meet the needs of eligible retail customers in the service areas of Commonwealth Edison Company ("ComEd") and Ameren Illinois Company ("Ameren Illinois"), as well as "small multi-jurisdictional utilities" should they request to participate.[22] The IPA Act directs that the procurement plan be developed and the competitive procurement process be conducted by "experts or expert consulting firms," respectively known as the "Procurement Planning Consultant"[23] and "Procurement Administrator."[24] The Commission is tasked with approval of the plan and monitoring of the procurement events through a Commission-hired "Procurement Monitor."[25]

Public Act 99-0906, effective June 1, 2017, modified the IPA's procurement planning process in part through the introduction of new requirements impacting the Agency. These requirements include the development of a separate zero emission standard procurement plan and the procurement of zero-emission credits from zero-emission generators (i.e., nuclear power plants);[26] the development of a separate long-term plan for the procurement of renewable energy resources (which includes the development of an adjustable block program to procure renewable energy credits from distributed generation and community solar projects; and the development of a low-income solar program using, in part, money held in the Renewable Energy Resources Fund);[27] and the elimination of the statutory requirement that the Agency include cost-effective incremental energy efficiency programs in its annual power procurement plan.[28]

[18] 220 ILCS 5/16-111.5(a).

[19] See 20 ILCS 3855/1-5(2)-(4).

[20] 20 ILCS 3855/1-5(1).

[21] See 20 ILCS 3855/1-20(a)(2), 1-75(a).

[22] 20 ILCS 3855/1-20(a)(1). MidAmerican elected to participate in IPA Procurement Plans starting in 2016 and will continue to participate in the 2021 Plan. See also 220 ILCS 5/16-111.5(a). ("This Section shall not apply to a small multi-jurisdictional utility until such time as a small multi-jurisdictional utility requests the Illinois Power Agency to prepare a procurement plan for its eligible retail customers.")

[23] 20 ILCS 3855/1-75(a)(1).

[24] 20 ILCS 3855/1-75(a)(2).

[25] 220 ILCS 5/16-111.5(b), (c)(2).

[26] See 20 ILCS 3855/1-75(d-5).

[27] See 20 ILCS 3855/1-75(c); Docket No. 17-0838.

[28] See 220 ILCS 5/16-111.5B.

Public Act 102-0662, effective September 15, 2021, contained significant additional changes to the IPA's renewable energy credit procurement obligations, and tasked the Agency with the development of a new procurement plan for the procurement of carbon mitigation credits from at-risk nuclear facilities.[29] Additionally, changes to Section 16-111.5 of the PUA could alter procurement strategies and bid evaluation for the Agency's future energy procurement processes.[30]

2.2 Procurement Plan Development and Approval Process

Although elements of the procurement planning process are ongoing (with the Agency continually soliciting and incorporating stakeholder input and lessons from past proceedings while monitoring ongoing energy market activity), the formal process for composing the 2025 Procurement Plan began on July 15, 2024. On that date, each Illinois utility that procures electricity through the IPA (ComEd, Ameren Illinois, and MidAmerican) submitted load forecasts to the Agency. These forecasts – which form the backbone of the Procurement Plan and which are covered in Sections 3.2, 3.3, and 3.4 in greater detail – cover a five-year planning horizon and include hourly data representing high, low, and base/expected scenarios for the load of the eligible retail customers.

After the receipt of load forecasts from the utilities, the IPA next prepared a draft Procurement Plan. The Draft 2025 Plan was made available for public review and comment on August 15, 2024. The Public Utilities Act provides for a 30-day comment period starting on the day the IPA releases its draft plan. The 2025 Plan comment period concluded on September 16, 2024.[31] As in prior years, during the 30-day comment period, the Agency held public hearings for the 2025 Plan virtually in lieu of the in-person meetings in each utility's service area.[32] Comments on the draft Plan were received from Ameren Illinois, ComEd, and Vistra.

After the receipt of public comments, the IPA revised the procurement plan as necessary based on the comments received, with that revised Plan required to be filed with the Commission within 14 days of the conclusion of that comment period, or by September 30, 2024.[33] The Agency filed this 2025 Plan with the Commission on September 30, 2024. Parties may file Objections within five days after the Plan is filed with the Commission; therefore, Objections must be filed on or by October 7, 2024.[34]

Under the PUA, the Commission approves the Procurement Plan, including the load forecasts contained within, if the Commission determines that "it will ensure adequate, reliable, affordable, efficient, and environmentally sustainable electric service at the lowest total cost over time, taking into account any benefits of price stability."[35]

2.3 Procurement Plan Requirements

At its core, the Procurement Plan consists of three pieces: (1) a forecast of how much energy (and in some cases capacity) is required by eligible retail customers; (2) the supply currently under contract; and (3) what type and how much supply must be procured to meet load requirements and to satisfy all other legal requirements associated with the Procurement Plan. To that end, the Procurement Plan must contain an hourly load analysis, which includes: multi-year historical analysis of hourly loads; switching trends and competitive retail market

[29] For more information on the Agency's Carbon Mitigation Credit Procurement Plan, see https://ipa.illinois.gov/energy-procurement/prior-approved-plans.html.

[30] Specifically, through changes to Section 16-111.5(b)(3)(iv), the statutory definition of "standard wholesale products" now includes "other standardized energy or capacity products designed to provide eligible retail customer benefits from commercially deployed advanced technologies including but not limited to high voltage direct current converter stations, as such term is defined in Section 1-10 of the Illinois Power Agency Act, whether or not such product is currently available in wholesale markets." Likewise, the assessment required under Section 16-111.5(b)(3)(vi) now includes consideration of "mitigation in the form of additional retail customer and ratepayer price, reliability, and environmental benefits from standardized energy products delivered from commercially deployed advanced technologies, including, but not limited to, high voltage direct current converter stations, as such term is defined in Section 1-10 of the Illinois Power Agency Act, whether or not such product is currently available in wholesale markets."

[31] Because the 30th day was Saturday September 14, 2024, the comment period closed the following Monday, September 16, 2024.

[32] The virtual public hearings on the Draft 2025 Plan were held using the Zoom platform at 9:30 a.m. (MidAmerican), 11:00 a.m. (Ameren Illinois), and 1:00 p.m. (ComEd) on Thursday, September 12, 2024.

[33] See 220 ILCS 5/16-111.5(d)(2).

[34] 220 ILCS 5/16-111.5(d)(3); see also 5 ILCS 70/1.11. Because the 5th day is Saturday, October 5, 2024, the Objection period closes the following Monday, October 7, 2024.

[35] 220 ILCS 5/16-111.5(d)(4).

analysis; known or projected changes to future loads; and growth forecasts by customer class.[36] In addition, the Procurement Plan must analyze the impact of demand side and renewable energy initiatives, including the impact of demand response programs and energy efficiency programs, both current and projected.[37] Based on the hourly load analysis, the Procurement Plan must detail the IPA's plan for meeting the expected load requirements that will not be met through pre-existing contracts,[38] and in doing so must:

- Define the different Illinois retail customer classes for which supply is being purchased, and include monthly forecasted system supply requirements, including expected minimum, maximum, and average values for the planning period.[39]
- Include the proposed mix and selection of standard wholesale products for which contracts will be executed during the next year that, separately or in combination, will meet the portion of the load requirements not met through pre-existing contracts or in the case of MidAmerican, including allocations to eligible Illinois customers of energy and capacity from company owned generating resources.[40] Such standard wholesale products include, but are not limited to, monthly 5 x 16 peak period block energy, monthly off-peak wrap energy, monthly 7 x 24 energy, annual 5 x 16 energy, annual off-peak wrap energy, annual 7 x 24 energy, monthly capacity, annual capacity, peak load capacity obligations, capacity purchase plan, and ancillary services.[41]
- Detail the proposed term structures for each wholesale product type included in the portfolio of products.[42]
- Assess the price risk, load uncertainty, and other factors associated with the proposed portfolio measures, including, to the extent possible, the following factors: contract terms; time frames for security products or services; fuel costs; weather patterns; transmission costs; market conditions; and the governmental regulatory environment.[43] Certain load forecasts for the 2023 Plan also take into account the estimated impact of the ongoing COVID-19 pandemic on the eligible customers' electricity demand. For those portfolio measures that are identified as having significant price risk, the Plan shall identify alternatives to those measures.
- For load requirements included in the Plan, include the proposed procedures for balancing loads, including the process for hourly load balancing of supply and demand and the criteria for portfolio re-balancing in the event of significant shifts in load. [44]
- Include demand-response products, as discussed below.

Procurements of standard wholesale products may include energy from high voltage direct current ("HVDC") transmission lines with converter stations located in Illinois.[45] The Agency may consider how products supplied by HVDC transmission lines can be bid into the competitive procurements for wholesale energy products on a basis that treats this source of supply equally with other sources of supply in selecting for contract awards.

[36] 220 ILCS 5/16-111.5(b)(1)(i)-(iv).

[37] 220 ILCS 5/16-111.5(b)(2), (b)(2)(i).

[38] 220 ILCS 5/16-111.5(b)(3).

[39] 220 ILCS 5/16-111.5(b)(i), (b)(iii).

[40] 220 ILCS 5/16-111.5(b)(3)(iv).

[41] Id.

[42] 220 ILCS 5/16-111.5(b)(3)(v).

[43] 220 ILCS 5/16-111.5(b)(3)(vi).

[44] 220 ILCS 5/16-111.5(b)(4).

[45] Id.

2.4 Standard Product Procurement

As noted in Section 2.3, the PUA provides examples of "standard wholesale products."[46] This listing has been understood by the Commission to be non-exhaustive and non-static.[47] Instead, as articulated by the Commission in approving the 2015 Plan, "[w]henever the Commission is confronted with a unique product, there must be an examination of the attributes of the product and whether those are consistent with other commonly traded products in the wholesale market" to determine whether the product meets this definition, and such products "must be routinely traded in a liquid market and have transparent prices that allow participants a degree of assurance that they are receiving fair market prices."[48] Standard wholesale products are further discussed in Section 5.2.2.6.

- Reading Subsection 16-111.5(b)(3)(vi) in conjunction with Subsection 16-111.5(e) and the ICC's Order approving the IPA's 2014 Procurement Plan,[49] the IPA understands that the definition of "standard product" also includes wholesale load-following products (including "full requirements" products) so long as the product definition is standardized such that bids may be judged solely on price.[50] With respect to demand-side products, in approving the 2015 Plan the Commission determined that block super-peak energy efficiency products proposed for procurement by the Agency "should not be procured at this time," but left open the possibility that "as demand-side markets evolve and energy efficiency products become more standardized, the Commission could envision a time in which these products might satisfy Section 16-111.5 of the PUA."[51]

2.5 Demand Response Products

The IPA may include cost-effective demand response products in its Procurement Plan. The Procurement Plan must include the particular "mix of cost-effective, demand-response products for which contracts will be executed during the next year, to meet the expected load requirements that will not be met through preexisting contracts."[52] Under the PUA, cost-effective demand-response measures may be procured whenever the cost is lower than procuring comparable capacity products, if the product and company offering the product meet minimum standards.[53] Specifically:

- The demand-response measures must be procured by a demand-response provider from eligible retail customers;[54]
- The products must at least satisfy the demand-response requirements of the regional transmission organization market in which the utility's service territory is located, including, but not limited to, any applicable capacity or dispatch requirements;[55]

[46] 220 ILCS 5/16-111.5(b)(3)(iv).

[47] See Docket No. 14-0588, Final Order dated December 17, 2014 at 156 ("the list enumerated in 16-111.5(b)(3)(iv) contains the phrase 'including but not limited to' which expands the list rather than limits it;" "the phrase 'standard wholesale products' cannot be static and it depends on the products that may be traded in wholesale markets at a given time").

[48] Id.

[49] While not adopting the Illinois Competitive Energy Association's full requirements proposal, the Commission's Final Order approving the IPA's 2014 Plan made clear that wholesale load-following products, including "full requirements" products, may qualify as a "standard product." See Docket No. 13-0546, Final Order dated December 18, 2013 at 94 ("the Commission agrees with Staff and the IPA that full requirements products should be considered a 'standard product' under Section 16-111.5").

[50] See, e.g., 220 ILCS 5/16-111.5(e)(2) (requiring development of standardized "contract forms and credit terms" for a procurement); 16-111.5(e)(3)-(4) (creation of a price-based benchmark and selection of bids "on the basis of price"); Docket No. 09-0373, Final Order dated December 28, 2009 at 115-116 (Commission approval of long-term renewable resource PPA project selection based on price alone). Note also that the Commission's Order approving the 2015 Procurement Plan indicates that "as demand-side markets evolve and energy efficiency products become more standardized, the Commission could envision a time in which these products might satisfy Section 16-111.5 of the PUA." (Docket No. 14-0588, Final Order dated December 17, 2014 at 156).

[51] Docket No. 14-0588, Final Order dated December 17, 2014 at 156.

[52] 220 ILCS 5/16-111.5(b)(3)(ii).

[53] Id.

[54] 220 ILCS 5/16-111.5(b)(3)(ii)(A).

[55] 220 ILCS 5/16-111.5(b)(3)(ii)(B).

- The products must provide for customers' participation in the stream of benefits produced by the demand-response products; [56]
- The provider must have a plan for the reimbursement of the utility for any costs incurred as a result of the failure of the provider to perform its obligations;[57] and
- Demand-response measures included in the plan shall meet the same credit requirements as apply to suppliers of capacity in the applicable regional transmission organization market.[58]

Public Act 97-0616, the Energy Infrastructure Modernization Act ("EIMA"), required ComEd and Ameren Illinois to file tariffs instituting an opt-in market-based peak time rebate ("PTR") program with the Commission within 60 days after the Commission approved the utility's Advanced Metering Infrastructure ("AMI") Plan.[59] ComEd's PTR program was provisionally approved in Docket No. 12-0484, and Ameren Illinois' PTR program was likewise provisionally approved in Docket No. 13-0105.[60] These programs are discussed further in Section 7.4, where demand response resource choices are examined.

Public Act 99-0906 made significant revisions to the energy efficiency and demand response portfolio standard found in Section 8-103 of the Public Utilities Act, creating new requirements that became effective on January 1, 2018. On June 30, 2017, ComEd filed its 2018-2021 Energy Efficiency and Demand Response Plan; for its demand response goal, ComEd proposed to implement a demand response program element that would fund the enrollment into its air conditioning ("AC") cycling program of any purchasers of qualified smart thermostats from ComEd's other residential program elements.[61] Ameren Illinois also filed its Energy Efficiency and Demand-Response Plan on June 30, 2017; Ameren Illinois proposed to achieve demand response reductions and meet its obligations under Section 8-103B(g)(4.5) through the peak demand reduction coincident to the electric energy efficiency savings proposed in its plan.[62] These Plans were both approved by the Commission on September 11, 2017.[63]

Ameren Illinois and ComEd filed new energy efficiency plans as required by March 1, 2021 to cover the 2022-2025 period.[64] Ameren once again proposed to achieve its demand response goal through coincident peak demand reduction achieved by the energy efficiency portfolio; this proposal was approved by the Commission on July 22, 2021.[65] Like Ameren, ComEd also proposed to utilize the same approach as in its prior plan to achieve its demand response goal. The Commission approved ComEd's proposal to continue to meet its demand response goals through its residential and income-eligible energy efficiency programs on June 24, 2021.[66]

2.6 Clean Coal Portfolio Standard

The IPA Act contains an aspirational goal that cost-effective clean coal resources will account for 25% of the electricity used in Illinois by January 1, 2025.[67] As a part of the goal, the Plan must also include electricity generated from clean coal facilities.[68] While there is a broader definition of "clean coal facility" contained in the definition section of the IPA Act,[69] Section 1-75(d) describes two special cases: the "initial clean coal facility"[70] and "electricity generated by power plants that were previously owned by Illinois utilities and that have been

56 220 ILCS 5/16-111.5(b)(3)(ii)(C).

57 220 ILCS 5/16-111.5(b)(3)(ii)(D).

58 220 ILCS 5/16-111.5(b)(3)(ii)(E).

59 220 ILCS 5/16-108.6(g).

60 See Docket No. 12-0484, Interim Order dated February 21, 2013 at 32; Docket No. 13-0105, Interim Order dated January 7, 2014 at 19.

61 See Docket No. 17-0312, Final Order dated September 11, 2017 at 19.

62 See Docket No. 17-0311, Final Order dated September 11, 2017 at 46-47.

63 The Commission's approval of the Ameren Illinois plan in Docket No. 17-0311 was appealed by the People of the State of Illinois, through the Office of the Attorney General, to the Illinois Appellate Court, Fourth District under Case No. 4-17-0870.

64 220 ILCS 5/8-103B(f)(2).

65 See Docket No. 21-0158, Final Order dated July 22, 2021 at 15.

66 See Docket No. 21-0155, Final Order dated June 24, 2021 at 12, 25.

67 20 ILCS 3855/1-75(d).

68 20 ILCS 3855/1-75(d)(1).

69 20 ILCS 3855/1-10.

70 Id.

or will be converted into clean coal facilities" (i.e., "retrofit clean coal facility").[71] Currently, there is no facility meeting the definition of an "initial clean coal facility" or a "retrofit clean coal facility" that the IPA is aware of, that has announced plans to begin operations within the next five years. A discussion of the considerations and challenges associated with possible clean coal procurements is contained in Section 7.5.

In Docket No. 12-0544, the Commission approved inclusion of the FutureGen 2.0 project as a "retrofit clean coal facility" starting in the 2017-2018 Delivery Year; that administrative approval and the associated cost recovery mechanism were subsequently appealed, and initially upheld by the Illinois First District Appellate Court.[72] With an appeal still pending before the Illinois Supreme Court, the U.S. Department of Energy ("U.S. DOE") announced in February 2015 that federal funding for the project would be suspended.[73] The FutureGen Alliance's Board of Directors "approved a resolution, dated January 6, 2016, ceasing all FutureGen Project development efforts"[74] and FutureGen exercised its right to terminate the prior-approved FutureGen 2.0 Sourcing Agreements with ComEd and Ameren Illinois. The Illinois Supreme Court subsequently dismissed the pending appeal of the appellate court's decision as moot through a May 2016 ruling, vacating the judgment of the appellate court without expressing an opinion on its merits while refraining from vacating those portions of the Commission's Order approving the 2013 Procurement Plan concerning FutureGen 2.0 sourcing agreements and related authority.[75]

2.7 Recent Legislative Proposals and Related Developments

Incremental energy efficiency programs and renewable energy resource procurement provided for the bulk of contested issues in past IPA Annual Electricity Plan approval proceedings prior to the enactment of Public Act 99-0906. Under changes made to Section 1-75(c) of the IPA Act and Section 16-111.5 of the PUA through Public Act 99-0906, the Agency's responsibility for renewable energy resource procurement has transitioned from meeting percentage-based renewables requirements applicable to eligible retail customer load to meeting similar percentage-based requirements for <u>all</u> retail customer load, handled exclusively through a separate planning process.[76] The number of contested issues and intensity of arguments in attaining approval of the IPA's annual electricity procurement plan has reduced significantly in recent years: there were just two contested issues for the 2018 Plan, no contested issues for the 2019 Plan, one contested issue for the 2020 Plan, no contested issues for the 2021 and 2022 Plans, three contested issues for the 2023 Plan, and one contested issue for the 2024 Plan.

The enactment of omnibus energy legislation, often referred to as the Climate and Equitable Jobs Act, through Public Act 102-0662 (effective September 15, 2021) significantly expanded the Agency's responsibilities. Many of these additional responsibilities, such as the carbon mitigation credit procurement and coal-to-solar procurements, were handled through separate processes from this Plan; nonetheless, changes of this magnitude can provide impacts on the development of the Agency's annual electricity procurement plans (as evidenced, for example, by comments received in the litigation surrounding the 2023 Electricity Plan advocating for the adjustment of electricity procurement hedging strategies for ComEd based on the presence of carbon mitigation credit delivery contracts).

As outlined above, the IPA is tasked with developing a separate Long-Term Renewable Resources Procurement Plan through which it proposes procurements and programs to meet Illinois RPS targets.[77] The Agency's initial Long-Term Renewable Resources Procurement Plan was approved by the Commission in Docket No. 17-0838 on April 3, 2018; it has subsequently been revised, and that Revised Plan was approved by the Commission on February 18, 2020 through Docket No. 19-0995. A Draft Second Revised Long-Term Plan was published concurrent with publication of the Draft 2022 Procurement Plan; however, due to changes to Section 1-75(c)(1)(A) of the IPA Act made pursuant to the enactment of Public Act 102-0662, the Draft Second Revised

[71] 20 ILCS 3855/1-75(d)(5).

[72] Commonwealth Edison Co. v. Ill. Commerce Comm'n, et al., 2014 IL App (1st) 130544, July 22, 2014.

[73] See, e.g., http://www.chicagobusiness.com/article/20150203/NEWS11/150209921/futuregen-clean-coal-plant-is-dead.

[74] Supplemental Brief of Appellee FutureGen Industrial Alliance, Inc. on the Issue of Mootness, dated January 13, 2016, at 1.

[75] Commonwealth Edison Co. v. Ill. Commerce Comm'n, et al., 2016 IL 118129, May 19, 2016.

[76] See 20 ILCS 3855/1-75(c)(1)(B). Among other changes, the revised law also now features quantitative targets for the procurement of renewable energy credits from new generating facilities as well. (See 20 ILCS 3855/1-75(c)(1)(C)).

[77] See 20 ILCS 3855/1-56(b)(2).

Long-Term Plan was withdrawn. The IPA released a draft 2022 Long-Term Plan on January 13, 2022. After the receipt of public comments on that draft Plan, the Agency updated the Plan and on March 21, 2022 filed the 2022 Long-Term Plan for approval by the Commission. On July 14, 2022 the Commission approved the 2022 Long-Term Plan in Docket No. 22-0231. On December 2, 2022, the Agency petitioned the ICC to reopen the proceeding that approved the 2022 Long-Term Plan to potential expansion of the Equity Eligible Contractor category in the Adjustable Block Program. That process culminated in the ICC issuing a Final Order modifying the 2022 Long-Term Plan on May 4, 2023, and the Agency released a Modified 2022 Long-Term Plan on May 9, 2023. On August 15, 2023, concurrent with the release of the draft of this 2024 Electricity Procurement Plan, the Agency also released its Draft 2024 Long-Term Plan for public comment. After the receipt of public comments on that draft Plan, the Agency updated the Plan and filed the 2024 Long-Term Plan for Commission approval on October 20, 2023. The 2024 Long-Term Plan was approved by the ICC on February 20, 2024, and the Final version of that Plan was published on April 19, 2024.

No legislation was passed in Spring 2024 session of the 103rd Illinois General Assembly that directly impacts this annual electricity procurement plan. However, a multitude of bills have been introduced that would reshape the state's future energy priorities, including proposals featuring both direct and indirect impacts on this annual electricity procurement planning process. These include the following:

- SB 3959/HB 5856 (creating energy storage targets, policies to facilitate energy storage targets, and featuring changes to the State's RPS)
- SB 3957/HB 5855 (creating even more ambitious energy storage targets with specific support outline for projects located at former fossil-fuel energy generation facilities)
- SB 3949 (creating HVDC REC procurement targets)
- HB 5514 (providing support for a new HVDC transmission line and providing for HVDC REC procurement targets)
- SB 3637/HB 5021 (requiring municipal utilities and rural electric cooperatives to create integrated resource plans and file those plans with the IPA)

The IPA expects robust discussion about these proposals and others through the end of calendar year 2024 and looks forward to providing feedback across any resulting working group or bill negotiation sessions in the months ahead.

On a national level, litigation and federal policy decisions have continued to shape the United States Environmental Protection Agency's ("U.S. EPA") approach to limiting CO_2 emissions from coal-fired power plants. On August 3, 2015, the U.S. EPA released its Clean Power Plan rules promulgated pursuant to Section 111(d) of the Clean Air Act, requiring states to develop strategies intended to reduce carbon dioxide emissions associated with electricity generation. On February 9, 2016, the U.S. Supreme Court stayed implementation of the Clean Power Plan pending judicial review.[78] Under the Clean Power Plan, initial state compliance plans were scheduled to be due to the U.S. EPA by September 6, 2016, but the stay delayed the timing for the state compliance plan development. In March 2017, President Trump issued an Executive Order seeking to revise or terminate the Clean Power Plan,[79] and on October 16, 2017, U.S. EPA published a Proposed Rule to repeal the Clean Power Plan.[80] On December 28, 2017, U.S. EPA published an Advance Notice of Proposed Rulemaking with the purpose of soliciting public comment on a new rule to regulate greenhouse gas ("GHG") emissions from existing electric generating units, written comments were due by February 26, 2018.[81] On July 9, 2018 a draft of a new rule, which would replace the Clean Power Plan, was sent to the White House for review.[82]

[78] See, e.g., http://www.nytimes.com/2016/02/10/us/politics/supreme-court-blocks-obama-epa-coal-emissions-regulations.html; http://www.scotusblog.com/wp-content/uploads/2016/02/15A773-Clean-Power-Plan-stay-order.pdf.

[79] See, e.g., https://www.nytimes.com/2017/03/28/climate/trump-executive-order-climate-change.html; https://www.whitehouse.gov/the-press-office/2017/03/28/presidential-executive-order-promoting-energy-independence-and-economi-1.

[80] See https://www.regulations.gov/document?D=EPA-HQ-OAR-2017-0355-0002.

[81] See https://www.regulations.gov/document?D=EPA-HQ-OAR-2017-0545-0001; https://www.regulations.gov/docketBrowser?rpp=25&so=DESC&sb=commentDueDate&po=0&dct=PS&D=EPA-HQ-OAR-2017-0545.

[82] Proctor, D., "EPA Sends Replacement for Clean Power Plan to Trump," www.powermag.com/category/coal/, July 10, 2018.

The U.S. EPA released its proposed rulemaking, titled the "Affordable Clean Energy" ("ACE") rule, on August 21, 2018.[83] On June 19, 2019, the EPA issued the final rule to replace the Clean Power Plan. The ACE rule established emissions guidelines for states to use for developing limits to CO_2 emissions from coal-fired power plants which identifies coal plant heat rate improvements as the best system of emission reduction (BSER).[84] The ACE rule is generally less stringent as compared with the Clean Power Plan (which would have imposed limitations on emissions from power plants to be achieved through switching power plant fuels from coal to natural gas, increasing generation from renewable resources, or requiring new coal-fired plants to meet low CO_2 emissions limits only possible through the use of carbon capture technology).[85]

Litigation regarding the ACE rule commenced in August 2019 when a coalition of 23 state Attorneys General filed a lawsuit in the D.C. Circuit Court of Appeals challenging the ACE rule.[86] On March 23, 2020, the D.C. Circuit issued a revised brief schedule. All parties were required to submit their final briefs by August 13, 2020, with oral argument held on October 8, 2020.[87] On January 19, 2021, the D.C. Circuit vacated the ACE Rule and remanded it to the EPA. The decision vacating the ACE did not reinstate the CPP.[88]

On August 16, 2022, President Biden signed the Inflation Reduction Act of 2022 ("IRA") into law. This legislation is expected to result in substantial greenhouse gas reductions through providing extensive tax incentives supporting wind and solar energy projects, the development of nuclear power technology, geothermal energy, carbon capture and storage, and zero-carbon fuels, along with improved methane abatement in the oil and gas industries. Greenhouse gas reductions are expected to be reduced by a cumulative 6.3 billion metric tons through 2032.[89] The electricity markets will likely be impacted by increased 45Q tax credits[90] providing incentives to install economically viable carbon capture and storage technologies at new and existing natural gas power plants and existing coal power plants. In an effort to increase the impact of the IRA in supporting new green energy developments, the U.S. Treasury Department and Internal Revenue Service released clarifying guidance regarding the investment tax credit and production tax credit provisions of the IRA. On May 12, 2023 guidance was released regarding the availability of a 10 percent domestic credit bonus to be added to the investment tax credit and production tax credit provisions of the IRA for qualifying projects that use steel and other products manufactured in the U.S.[91] On June 14, 2023 additional guidance was released that will enable state governments, local governments, and non-profit entities to take better advantage of the IRA's clean energy tax credits by allowing entities without sufficient tax liabilities to receive full credit for the tax credits through new credit delivery mechanisms.[92]

The EPA announced the final standards for limiting carbon emissions from coal-fired and natural gas-fired power plants on April 25, 2024.[93] Following the announcement, several industry groups and states requested that the implementation of the rule by the EPA be blocked during litigation challenging the standards. On July 19, 2024, the U.S. Court of Appeals for the District of Columbia denied the request. On July 23, 2024, a group of

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[83] Emissions Guidelines for Greenhouse Gas Emissions From Existing Electric Utility Generating Units; Revisions to Emission Guideline Implementing Regulations; Revisions to New Source Review Program, 83 Fed. Reg. 44746 (August 31, 2018); see also https://www.epa.gov/stationary-sources-air-pollution/proposal-affordable-clean-energy-ace-rule.

[84] See: https://www.epa.gov/stationary-sources-air-pollution/affordable-clean-energy-rule.

[85] "Goodbye, Clean Power Plan: Stanford researchers discuss the new energy rule," Stanford Woods Institute for the Environment, June 21, 2019.

[86] See, e.g.,: http://biomassmagazine.com/articles/17436/oral-arguments-held-in-challenge-to-epaundefineds-ace-rule.

[87] Congressional Research Service Report R46482, "EPA's Affordable Clean Energy Rule and Related Issues: Frequently Asked Questions," August 13, 2020.

[88] U.S. EPA, Office of Air and Radiation, Memorandum: Status of Affordable Clean Energy Rule and Clean Power Plan, February 12, 2021.

[89] Princeton University Zero-carbon Energy Systems Research and Optimization Laboratory, "Preliminary Report: The Climate and Energy Impacts of the Inflation Reduction Act of 2022," August 2022. http://repeatproject .org/REPEAT_IRA_Preliminary_Report_2022_08_04.pdf.

[90] A "45Q tax credit" is a tax credit under Internal Revenue Code Section 45Q intended to incentivize investment in carbon capture and sequestration.

[91] See https://www.whitehouse.gov/cleanenergy/clean-energy-updates/2023/05/12/treasury-releases-new-guidance-strenthening-incentives-for-domestic-clean-energy-manufacturing/ .

[92] See https://home.treasury.gov/news/press-releases/jy1533.

[93] Fact Sheet Carbon Pollution Standards for Fossil-Fuel-Fired Power Plants Final Rule Standards and Regulatory Impact. https://www.epa.gov/system/files/documents/2024-04/cps-111-fact-sheet-standards-and-ria-2024.pdf.

25 states filed an emergency petition with the U.S. Supreme Court to block implementation of the standards while litigation over the standards is pursued in federal courts.[94]

[94] States' Emergency Application for an Immediate Stay of Administrative Action Pending Review in the D.C. Circuit, https://ago.wv.gov/Documents/Carbon%20Rule%20Stay%20Application.pdf.

3 Load Forecasts

3.1 Statutory Requirements

Under Illinois law, a procurement plan must be prepared annually for each "electric utility that on December 31, 2005 served at least 100,000 customers in Illinois."[95] Section 16-115(a) of the PUA allows small multi-jurisdictional electric utilities to elect to have the IPA procure power and energy for all or a portion of its eligible retail customer load in Illinois. Besides the two electric utilities that serve at least 100,000 customers in Illinois, Ameren Illinois and ComEd, a third electric utility, MidAmerican, which serves fewer than 100,000 electric customers in Illinois, has elected to have the IPA procure electricity[96] for a portion of its load.[97] The plan must include a load forecast based on an analysis of hourly loads. The statute requires the analysis to include:

- Multi-year historical analysis of hourly loads;
- Switching trends and competitive retail market analysis;
- Known or projected changes to future loads; and
- Growth forecasts by customer class.[98]

The statute also defines the process by which the procurement plan is developed. The load forecasts themselves are developed by the utilities as stated in the statute:

> *Each utility shall annually provide a range of load forecasts to the Illinois Power Agency by July 15 of each year, or such other date as may be required by the Commission or Agency. The load forecasts shall cover the 5-year procurement planning period for the next procurement plan and shall include hourly data representing a high-load, low-load and expected-load scenario for the load of the eligible retail customers. The utility shall provide supporting data and assumptions for each of the scenarios.*[99]

The forecasts are prepared by the utilities, but the Procurement Plan is ultimately the responsibility of the Agency. The Commission is required to approve the plan, including the forecasts on which it is based. Therefore, the Agency must review and evaluate the load forecasts to ensure they are sufficient for the purpose of procurement planning. This Chapter contains a summary of the load forecasts for Ameren Illinois, ComEd, and MidAmerican and the Agency's evaluation of those load forecasts.

Note: Throughout this Plan, except where noted, the retail load is taken to include an allowance for losses. In other words, it represents the volume of energy that each utility must schedule to meet the load of its eligible retail customers at the RTO level (MISO for Ameren Illinois and MidAmerican, and PJM for ComEd).

3.2 Summary of Information Provided by Ameren Illinois

In compliance with Section 16-111.5(d)(1) of the Public Utilities Act, Ameren Illinois provided the IPA with the following documents for use in preparation of this Plan:

- Ameren Illinois Company Load Forecast for the period June 1, 2025 – May 31, 2030 (See Appendix B)
- Spreadsheets of the expected (base), high, and low load forecasts. (Summarized in Appendix E)

Ameren Illinois uses a combination of statistical and econometric modeling approaches to develop its customer class specific load forecast models. A statistically adjusted end-use approach is used for the residential and commercial customer classes. This approach combines the econometric model's ability to identify historic

[95] 220 ILCS 5/16-111.5(a).

[96] MidAmerican registers with MISO its generation resources allocated to serve its Illinois customers as historical resources. Incremental amounts of electricity refer to the capacity and energy that would be needed in addition to the historical resources to meet the projected loads.

[97] Utilities that serve fewer than 100,000 electric customers in Illinois are not obligated to, but "may elect to procure power and energy for all or a portion of their eligible Illinois retail customers" using the IPA process (220 ILCS 5/16-111.5(a)). This is the tenth annual procurement process in which MidAmerican elected to have the IPA procure power and energy for a portion of its Illinois jurisdictional load.

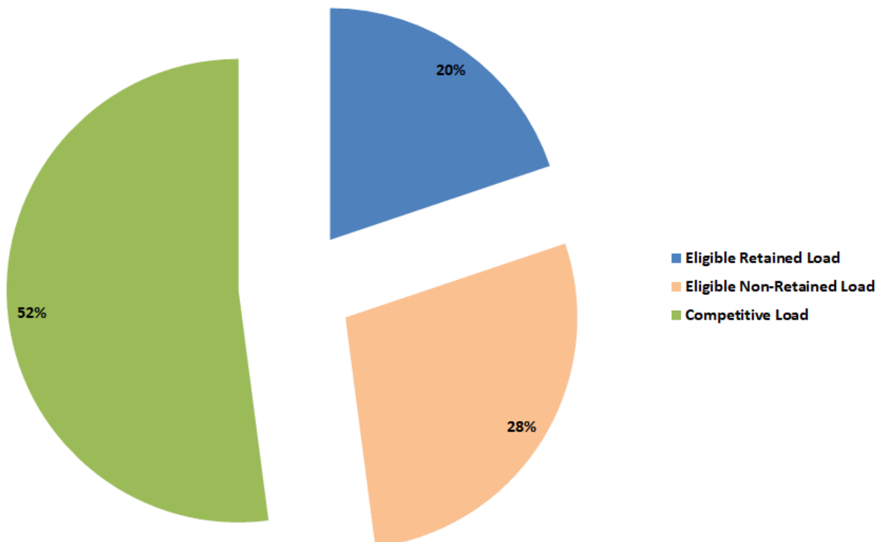
[98] 220 ILCS 5/16-111.5(b)(1).

[99] 220 ILCS 5/16-111.5(d)(1).

trends and project future trends with the end-use model's ability to identify factors driving customer energy use.

Industrial and public authority classes are modeled using a traditional econometric approach that correlates monthly sales, weather, seasonal variables, and economic conditions. The Lighting load class is modeled using either exponential smoothing or econometric models. Figure 3-1 shows Ameren's retail load forecasted annual energy usage percentage.[100]

Figure 3-1: Ameren Illinois' Forecast Retail Customer Load Breakdown, Delivery Year 2025-2026[101]

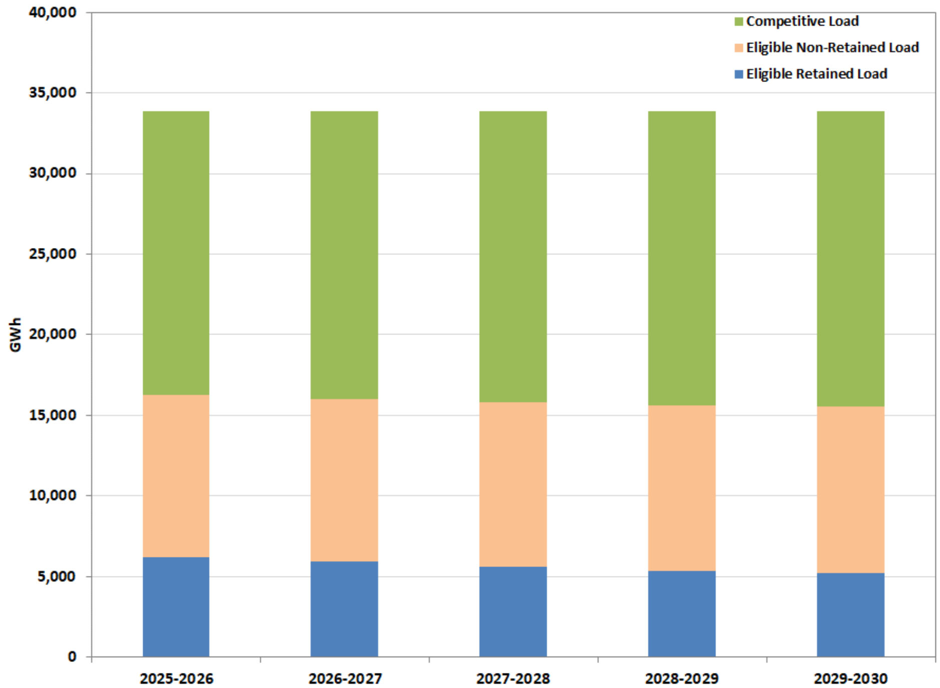


Ameren Illinois' forecasts are performed on the total Ameren Illinois delivery service load using a regression model applied to historical load and weather data. A separate analysis is performed for each customer class to account for the differing impacts of weather on the different customer classes. Figure 3-2 shows the Ameren Illinois 5-year forecast of its retail customer load.

[100] Ameren Illinois assigns load profile classifications at the point of service level and only to points of service that are metered. The classifications are as follows: DS-1 – Residential, DS-2 – Non-Time of Use Commercial & Industrial with demands less than 150 kW, DS-3 – Time of Use Commercial & Industrial with demands between 150 kW and 1,000 kW, DS-4 – Time of Use Commercial & Industrial with demands above 1,000 kW, and DS-5 – Lighting. The DS-3 and DS-4 classes are fully competitive, meaning that customers in these classes must receive supply from ARES or Ameren Illinois real time pricing. Customers in the DS-1, DS-2 and DS-5 classes are eligible to take fixed-price supply service from Ameren Illinois or an ARES. DS-6 is temperature sensitive service.

[101] For the 2025-2026 Delivery Year, Ameren Illinois' projected total Retail Load is forecasted to be 33,873,550 MWh, where the Eligible Retained Load accounts for 6,717,707 MWh, the Eligible Non-Retained Load accounts for 9,519,508 MWh, and the Competitive Load accounts for 17,636,335 MWh. The amount for the projected total Retail Load was provided by Ameren in their July 2024 response to the IPA Data Request for the 2025 Long-Term Plan.

Figure 3-2: Ameren Illinois' Forecast Retail Customer Load by Delivery Year

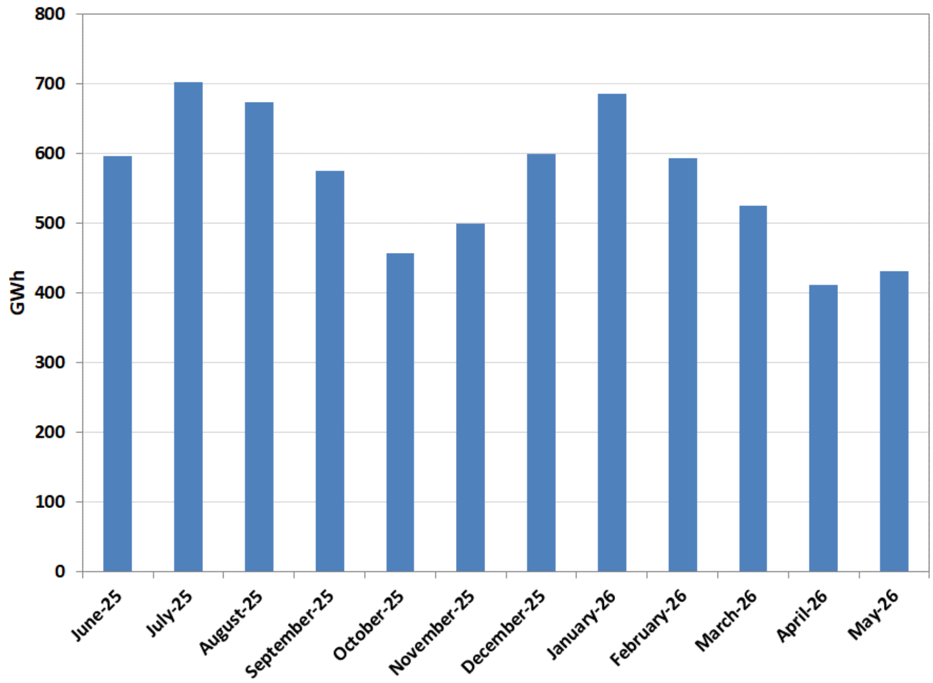


Ameren Illinois applies assumed "switching rates" to the total system load forecast to remove the load to be served by bundled hourly pricing (Power Smart Pricing or Rider HSS) and Alternative Retail Electric Suppliers, including municipal aggregation.[102] Ameren Illinois establishes the current customer switching trend line utilizing actual switching data by customer class. Qualitative judgment is used to make adjustments to the switching trend line. The portion of the forecasted load attributed to Rider HSS, municipal aggregation customers, and other ARES customers, is subtracted from the total system load forecast. The result is the forecasted load to be supplied by Ameren Illinois.

Figure 3-3 provides a monthly breakdown of the base-case forecast of Ameren Illinois eligible retail customer load, that is, the load of customers who are forecasted to take bundled supply procured under this Procurement Plan.

[102] Municipal aggregation of residential and small commercial retail customer load for contracting with ARES is authorized by the IPA Act, 20 ILCS 3855/1-92.

Figure 3-3: Ameren Illinois' Forecast Eligible Retained Retail Customer Load* by Month



*Total load, prior to netting QF supply.

Ameren Illinois provides a base case and two complete alternate cases: a low forecast and a high forecast. Each excursion case addresses three different uncertainties that simultaneously move in the same direction: macroeconomics, weather, and switching. This means, for example, that a high load case should represent the combination of stronger-than-expected economic growth (which increases load), extreme weather (which increases load) and a reduced level of switching (which increases the "eligible" fraction of retail load, that is, the fraction for which the utility retains the supply obligation). Similarly, a low load case should represent the combination of weaker-than-expected economic growth, mild weather and an increased level of switching.

3.2.1 Macroeconomics

The Ameren Illinois base case load forecast is based on a statistically adjusted end-use forecast that combines technological coefficients (efficiencies of various end-use equipment) and econometric variables (income levels and energy prices). Ameren Illinois did not define "high" and "low" cases by varying the econometric (or other) variables. Instead, Ameren Illinois looked at the statistics of the residuals from the model fit, and the high and low cases are based on a 95% confidence interval. For the residential electric customer class, Ameren Illinois currently projects a 5-year compound annual growth rate of -1.2%. This is a decrease from the 0.8% growth rate provided for the 2023 Plan. For commercial customers, the growth rate for Ameren Illinois is projected to be -1.2%. While for industrial customers, the growth rate for Ameren Illinois is projected to be 1.0%. See Section 3.5.1 for a discussion of how this load forecast compares to national trends in electricity load growth.

Ameren Illinois' "high" and "low" forecasts are uniform modifications of the base case, excluding incremental energy efficiency, by rate class. Specifically, in each case, a single multiplier is defined for each of the three non-fully competitive delivery service rate classes, and the "before switching" load forecast for every hour is multiplied by the rate class multiplier. Table 3-1 below shows the current rates for the low and high cases for each of the three rate classes.

Table 3-1: Load Multipliers in Ameren Illinois Excursion Cases

Rate Class	Low Case	High Case
DS-1	0.94	1.07
DS-2	0.94	1.07
DS-5	0.93	1.07

In regression models, residuals indicate the difference between the predicted and actual values. Patterns associated with residuals may indicate the impact of non-specified variables. Because the excursion cases are based on the statistics of the residuals, they reflect the influence of variables not modeled. The forecasting model appears to be dominated by technological and weather effects. The econometric variables are related to short-term decision-making. Uncertainty around long-term economic growth will appear in the residuals.

3.2.2 Weather

Ameren Illinois includes "high weather" and "low weather" in its characterization of the high and low cases. Ameren Illinois did not re-compute its load forecasting models with different values for the weather variables. The high and low scenarios only account for an average impact of weather, and macroeconomic effects, which is proportionally the same in each hour.

The low case is about 7% lower than the base case and the high case is about 7% higher than the base case. The difference between the high, low, and base cases are the variation Ameren Illinois attributes to macroeconomic effects and weather variables.

3.2.3 Switching

According to Ameren Illinois, customer switching to alternative retail electric suppliers, in particular through municipal aggregation, is the greatest driver of load uncertainty. As of June 1, 2024, customer switching has resulted in approximately 54% of residential and 68% small commercial load taking service from alternative retail electric suppliers rather than from Ameren's default service. Ameren Illinois expects that the amount of load supplied by ARES will remain flat across the planning horizon. They are kept flat "because AIC has no compelling information at this time that can indicate one direction or another."[103] The majority of municipal aggregation contracts expiring in this planning cycle occur in July 2024, August 2024, and January 2025. Ameren provided multiple load forecasts representing different switching scenarios.[104] Additionally, as shown in Table 3-2 presented in the next Section, ARES offerings to individual customers, in general, are higher than the default utility rate.

Ameren Illinois has also developed additional switching scenarios that address high and low switching scenarios for this planning period. A low switching scenario envisions a situation where a larger return of residential and, to a lesser extent, commercial customers, is realized. These scenarios reflect various switching rates which are the reflection of the percentage of load that is being served by alternative retail electric suppliers. Residential and small commercial switching rates under the low switching and a corresponding high load scenario are forecasted to be 47% and 60%, respectively, in May 2025, 39% and 53%, respectively, in May 2026, and 11% and 24%, respectively, by the end of the planning horizon.

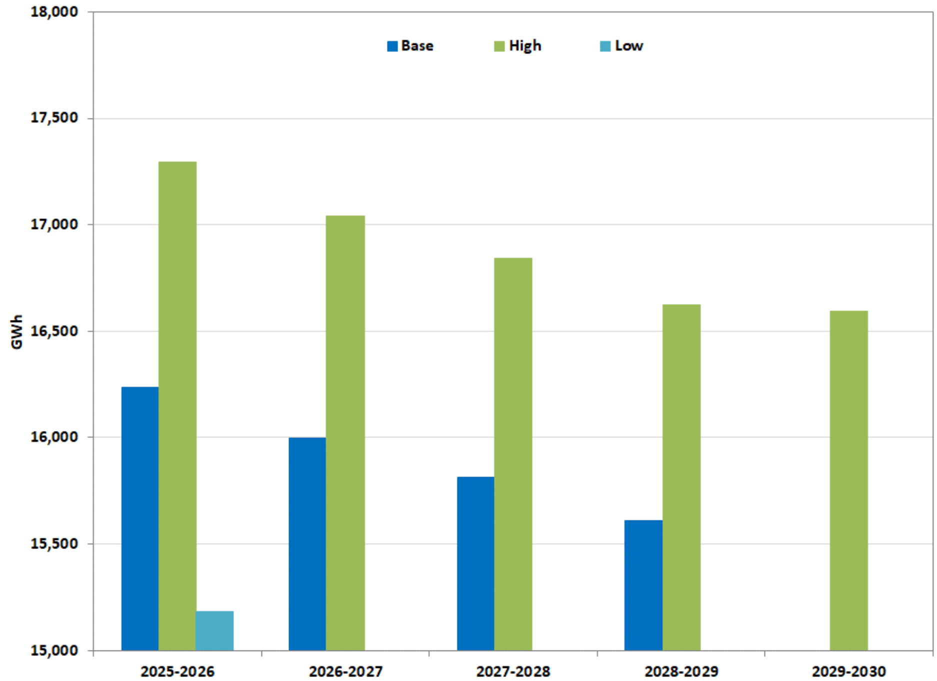
Conversely, should future Ameren Illinois tariff rates exceed customers' perceived value of ARES contracts, a higher switching scenario is possible. Thus, Ameren Illinois' high switching and a corresponding low load scenario assumes that residential and small commercial switching rates will approach 60% and 73%, respectively, in May 2025, 64% and 78%, respectively, in May 2026, and 84% and 97%, respectively, by the end of the planning horizon.

The difference in switching rates is the most significant factor driving the differences among the scenarios. Figure 3-4 shows the forecasted Ameren Illinois supply obligation to serve eligible retail customers in each case. The Base Case assumes the expected switching, the High Load assumes low switching, and the Low Load assumes high switching.

[103] See Ameren Load Forecast Submittal, Appendix B at https://ipa.illinois.gov/energy-procurement/2025-appendices.html.

[104] If some, or all, of these municipalities do not renew their contracts and customers return to default service, that additional load will be reflected in the March 2025 load forecasts and procurement volumes adjusted accordingly.

Figure 3-4: Supply Obligation in Ameren Illinois' Forecasts



3.2.4 Load Shape and Load Factor

Figure 3-5 and Figure 3-6 display the hourly profile of Ameren Illinois supply obligation in each case (relative to the daily maximum load). Figure 3-5 illustrates a summer day and Figure 3-6 a spring day. In these figures the curves are normalized so that the highest value in each is 1. There is little difference between the profiles of the high, low, and base cases.

Figure 3-5: Sample Daily Load Shape, Summer Day in Ameren Illinois' Forecasts

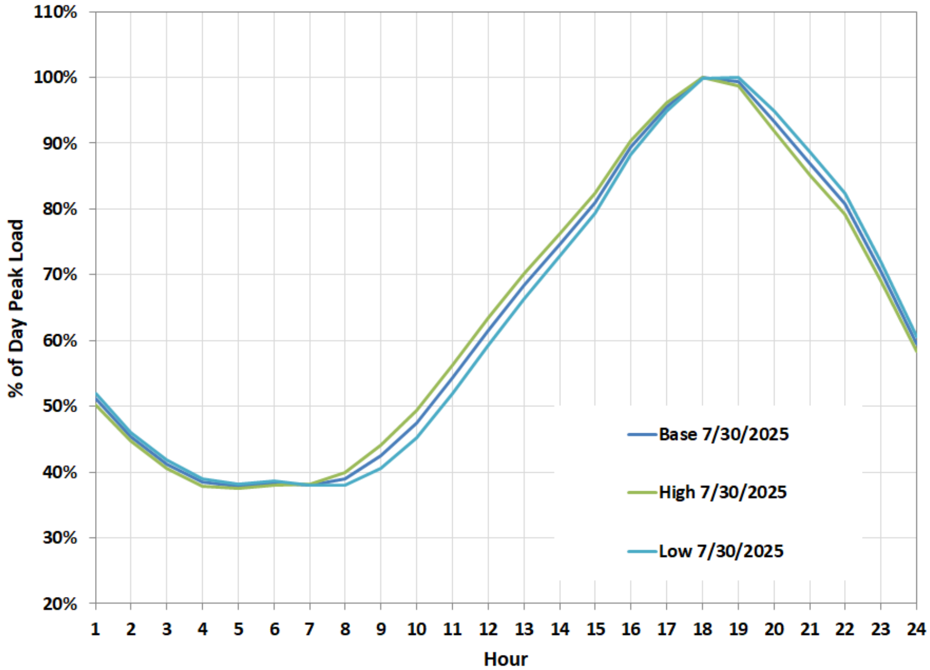
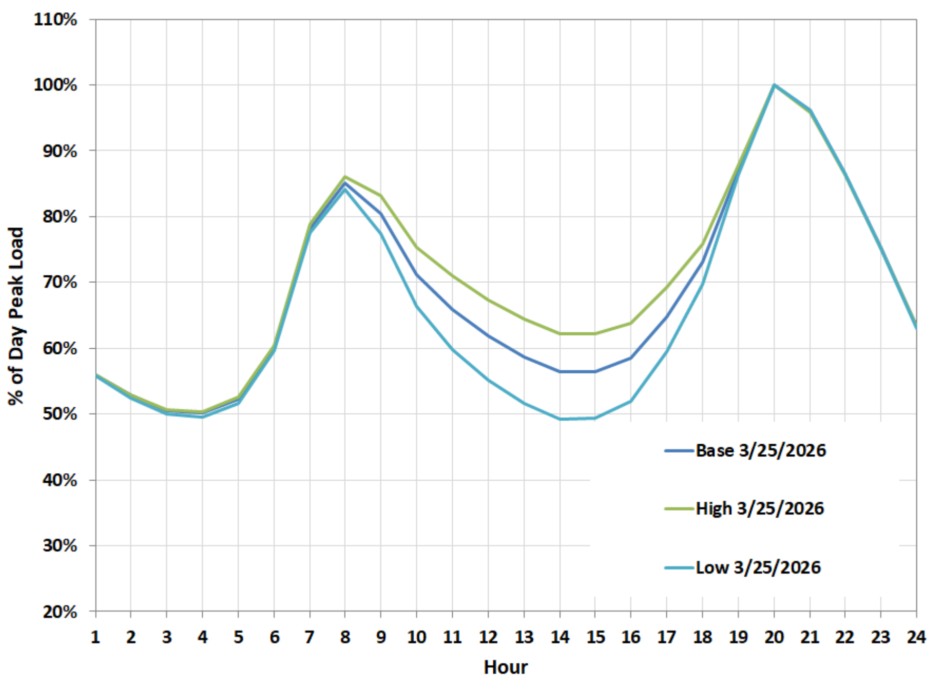


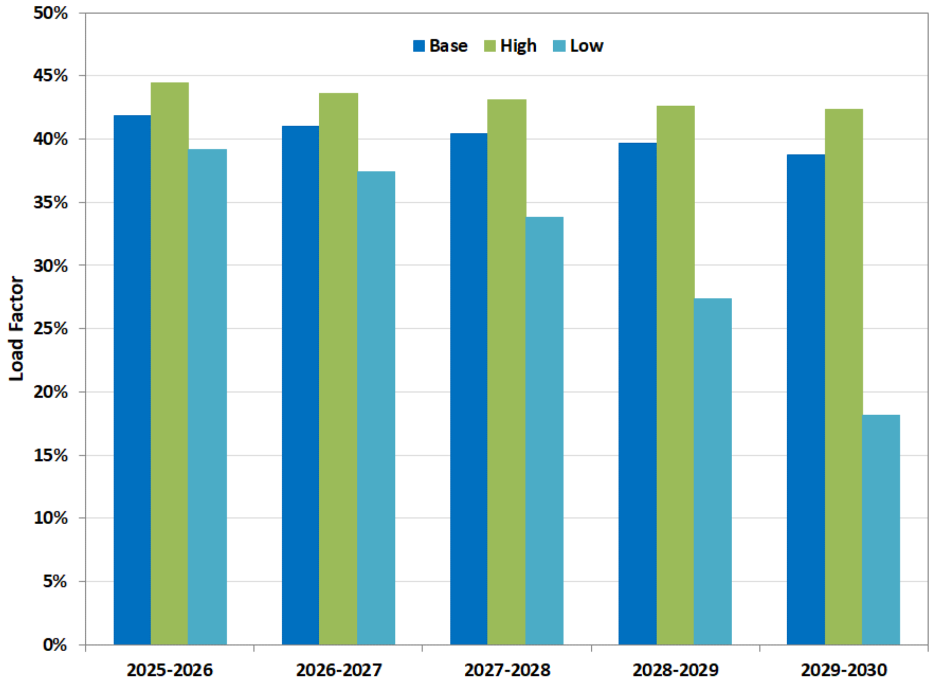
Figure 3-6: Sample Daily Load Shape, Spring Day in Ameren Illinois' Forecasts



A load shape can be called "peaky" if there is a lot of variation in it – for example, if there is a large difference between the lowest and highest load values. A load shape that is not peaky is one in which the load is nearly constant. The peakiness of a case is usually borne out by the load factors. The load factor in any time period, such as a year, is the ratio of the average load to the maximum load. In general, peaky load curves have low load factors.

Figure 3-7 shows that the low case has the lowest load factors, while Figure 3-5 and Figure 3-6 show that the low case load profile is not peakier than the other two cases as would be expected. This can be attributed to a difference in weather assumptions between the low case and the other two cases.

Figure 3-7: Load Factor in Ameren Illinois' Forecasts



3.3 Summary of Information Provided by ComEd

In compliance with Section 16-111.5(d)(1) of the Public Utilities Act, ComEd provided the IPA the following documents for use in preparation of this Plan:

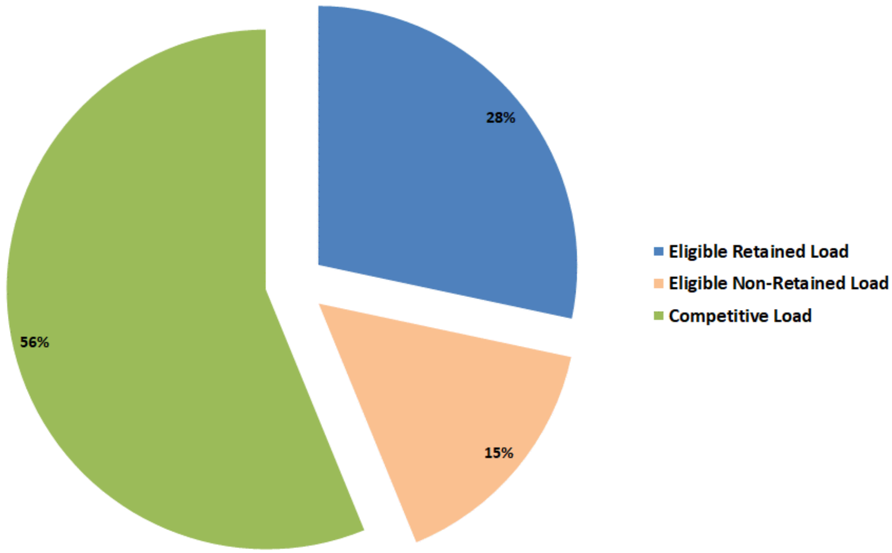
- *Load Forecast for Five-Year Planning Period June 2025 – May 2030.* (See Appendix C) This document also contained several appendices.
- Information supporting the load forecasts including spreadsheets of load profiles, hourly load strips, model inputs, procurement blocks, and scenario models for the base, high and low forecasts. (Summarized in Appendix F)[105]

ComEd forecasts load by applying hourly load profiles for each of the major customer groups to the total service territory annual load forecast and subtracting loads projected to be served by hourly pricing, ARES, and municipal aggregation. Hourly load profiles are developed based on statistically significant samples from ComEd's residential, non-residential watt-hour, and 0 to 100 kW delivery customer classes. The profiles show clear and stable weather-related usage patterns. Using the profiles and actual customer usage data, ComEd develops hourly load models that determine the average percentage of monthly usage that each customer group uses in each hour of the month.

ComEd did not supply its forecasts for medium and large commercial and industrial customers, whose service has been deemed to be competitive and who therefore cannot be eligible retail customers. Figure 3-8 shows ComEd's retail load forecasted annual energy usage percentage.

[105] In its July 15, 2024 Load Forecast, ComEd also included a brief discussion of the distributed generation penetration effect in its service territory.

Figure 3-8: ComEd's Forecast Retail Customer Load Breakdown, Delivery Year 2025-2026[106]



As noted above, ComEd provides a forecast of total usage for the entire service territory and allocates the usage to various customer classes using the models specific to each class. A suite of econometric models, adjusted for other considerations such as customer switching, is used to produce monthly usage forecasts. The hourly customer load models are applied to create hourly forecasts by customer class.

In determining the expected load requirements for which standard wholesale products will be procured, the ComEd forecast must be adjusted for the volume served by municipal aggregation and other ARES. The ComEd 5-year annual load forecast, shown in Figure 3-9, is based on the rate of customer switching in the past, expected increases in residential ARES service, and the anticipated additional migration of 0 to 100 kW customers to ARES and municipal aggregation. The figure breaks down the total forecast of retail customer load in the same way as Figure 3-8 does for a single year.

[106] For the 2025-2026 Delivery Year, ComEd's projected total Retail Load is 84,260 GWh, where the Eligible Retained Load accounts for 23,870 GWh, the Eligible Non-Retained Load accounts for 13,054 GWh, and the Competitive Load accounts for 47,337 GWh. The amount for the projected total Retail Load was provided by ComEd in their July 2024 response to the IPA Data Request for the 2025 Long-Term Plan.

Figure 3-9: ComEd's Forecast Retail Customer Load by Delivery Year

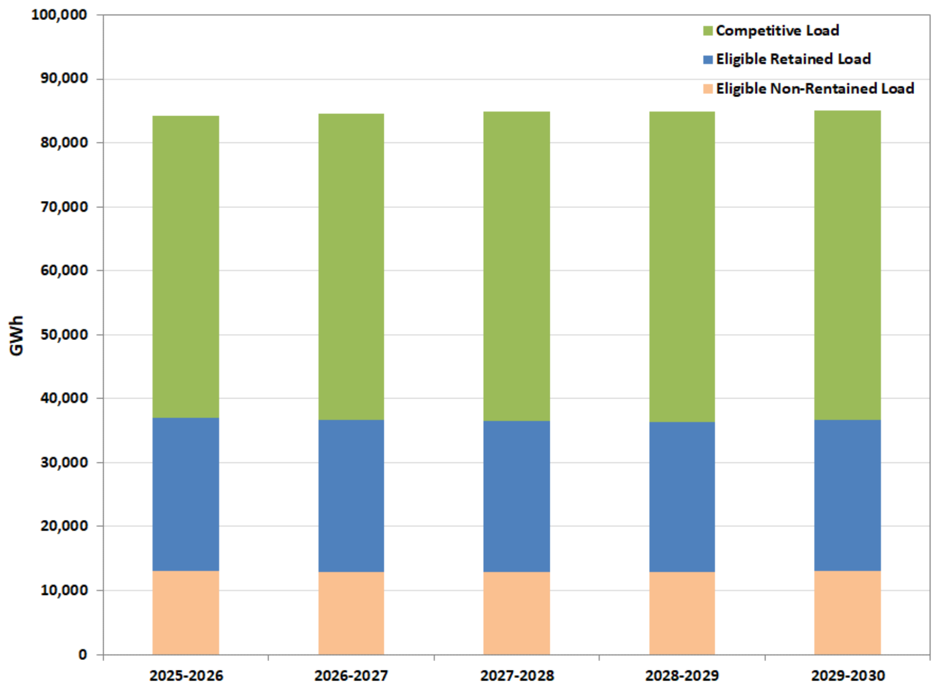
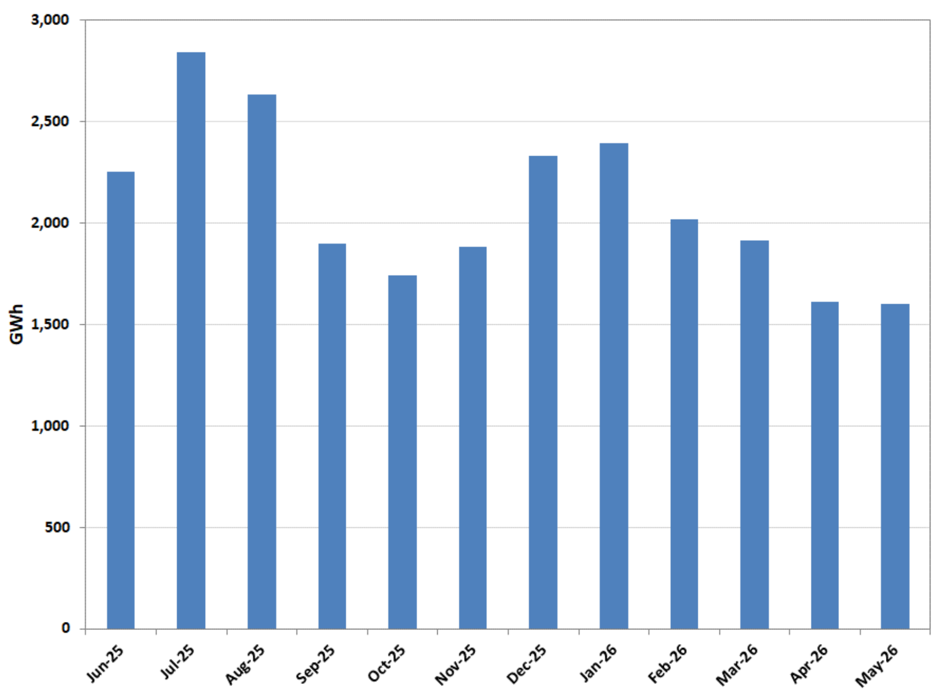


Figure 3-10 provides a monthly breakdown of the base-case forecast of ComEd's eligible retail customer load, that is, the load of customers who are forecasted to take bundled supply under this Procurement Plan.

Figure 3-10: ComEd's Forecast Eligible Retained Retail Customer Load by Month



ComEd provides a base case load forecast and two excursion cases: a low-case forecast and a high-case forecast. Each excursion case addresses three different uncertainties, simultaneously moving in the same direction: macroeconomics, weather, and switching.

3.3.1 Macroeconomics

ComEd's base case load forecast is driven by a Zone Model that includes both macroeconomic variables (Gross Metropolitan Product for Chicago and other metropolitan areas within ComEd's service territory, household income) and demographics (household counts). ComEd did not use this model to define "high" and "low" cases. ComEd modified the service area load growth rates, increasing them by 2% in the high case and reducing them by 2% in the low case (because the growth rate in the base case is projected to be flat to negative, presumably this implies negative load growth in the low case throughout the projection horizon). ComEd provided a June 2025 – May 2030 monthly expected load forecast, with a calculated annual growth rate of approximately -0.38%. This has fallen when compared to the June 2024 – May 2029 monthly expected load forecast provided in July 2023, of 0.8%. See Section 3.5.1 for a discussion of how this load forecast compares to national trends in electricity load growth.

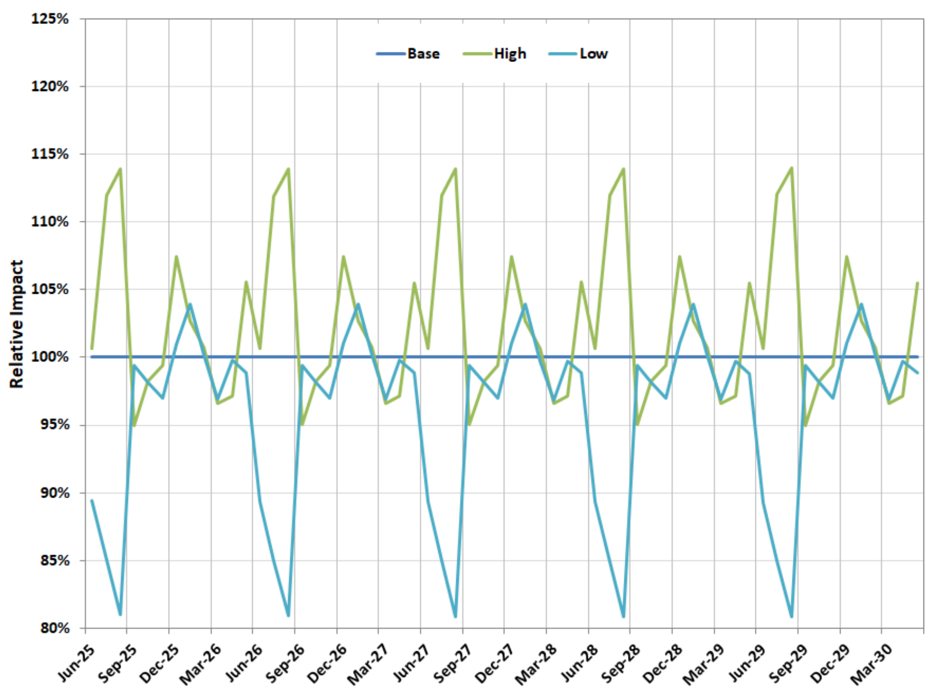
3.3.2 Weather

ComEd includes "high weather" and "low weather" in its characterization of the high and low cases. Under the sample year approach, the high-load forecast assumes that the summer weather is hotter than normal, and the low-load forecast assumes that the summer weather is cooler than normal.

ComEd has not provided the specific impacts of the load growth assumption (load forecasts in the absence of switching). ComEd did provide the impacts of the high weather and low weather cases on residential and small commercial load, relative to the base case forecast. The weather impacts are provided as percentages that summarize the hourly impacts of the effect of temperature on load.

Figure 3-11 shows the impact of weather on load by month. The figure compares the high and low weather usage factors to the base forecast weather usage factors in the form of ratios to the base case to gauge the relative impacts.

Figure 3-11: The Impact of Weather in ComEd's Forecasts

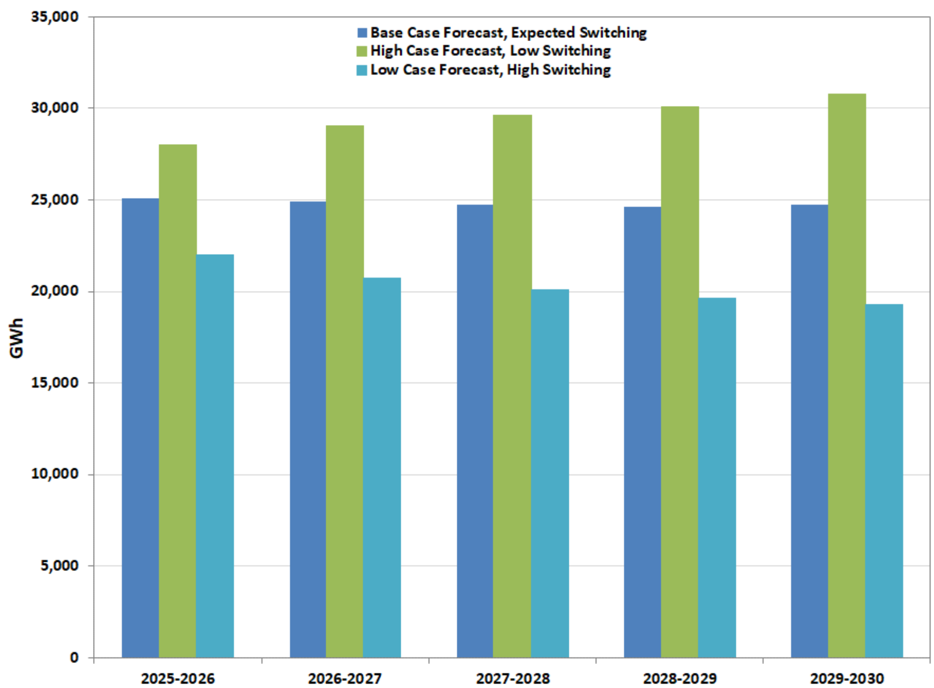


3.3.3 Switching

The high switching (low load) case assumes residential, watt-hour, and 0 to 100 kW blended service[107] usage will be reduced by a total of 4% by December 2025 and 6% by December 2026 as the communities that are opting out from ComEd service renew their municipal aggregation programs. Municipal aggregation has historically been a major factor in the rapid expansion of residential ARES supply. In total, there are 359 communities within the ComEd service territory that had approved aggregation as of June of 2024, with 200 of those communities actively being served through municipal aggregation (a decrease from 216 in June 2023). The percentage of potentially eligible retail customers taking blended service in this switching scenario is 60% (based on usage) as of December 2026 compared to 66% in the expected load forecast.

The low switching (high load) case assumes additional communities opt out of municipal aggregation such that residential usage increases by a total of 4% by December 2025 and 6% by December 2026 . The percentage of potentially eligible retail customers taking blended service in this switching scenario is 72% (based on usage) as of December 2026 compared to 66% in the expected load forecast. Figure 3-12 shows the forecasted ComEd supply obligation in each case. The Base Case assumes the expected switching, the High Load assumes low switching, and the Low Load assumes high switching.

Figure 3-12: Supply Obligation in ComEd's Forecasts



3.3.4 Load Shape and Load Factor

Figure 3-13 and Figure 3-14 display the hourly profile of the utility supply obligation in each case (relative to the daily maximum load). Figure 3-13 illustrates a summer day, and Figure 3-14 a spring day. There is no significant difference between the profiles of the high case and the base case on a summer day, but the low case is flatter. During the sample spring day, the base case is peakier than the high case, and the low case is slightly peakier than the base case.

[107] "Blended service" refers to eligible retail customers that purchase power and energy from ComEd under fixed-price bundled service tariffs.

Figure 3-13: Sample Daily Load Shape, Summer Day in ComEd's Forecasts

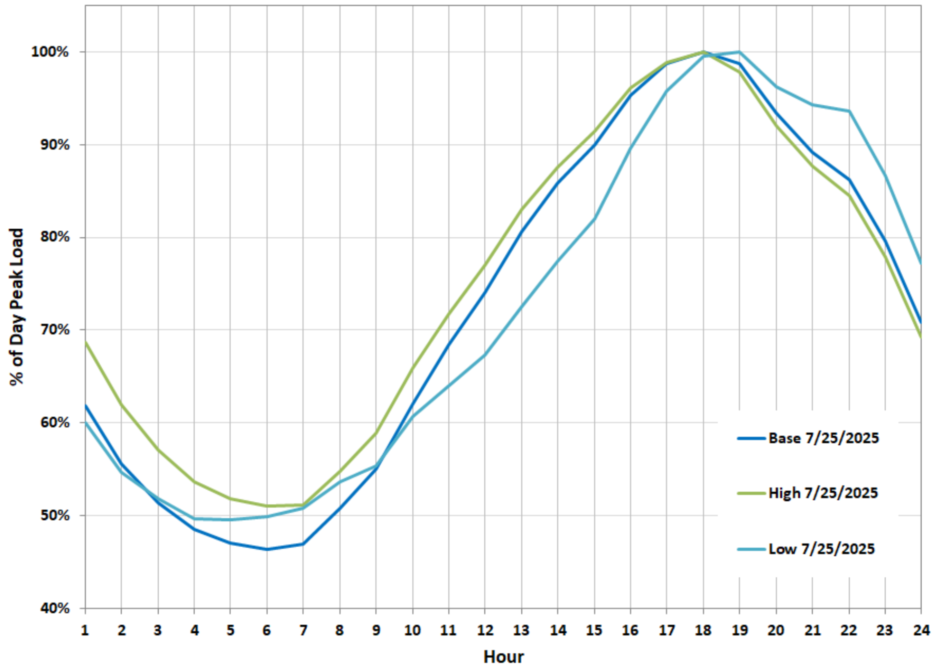
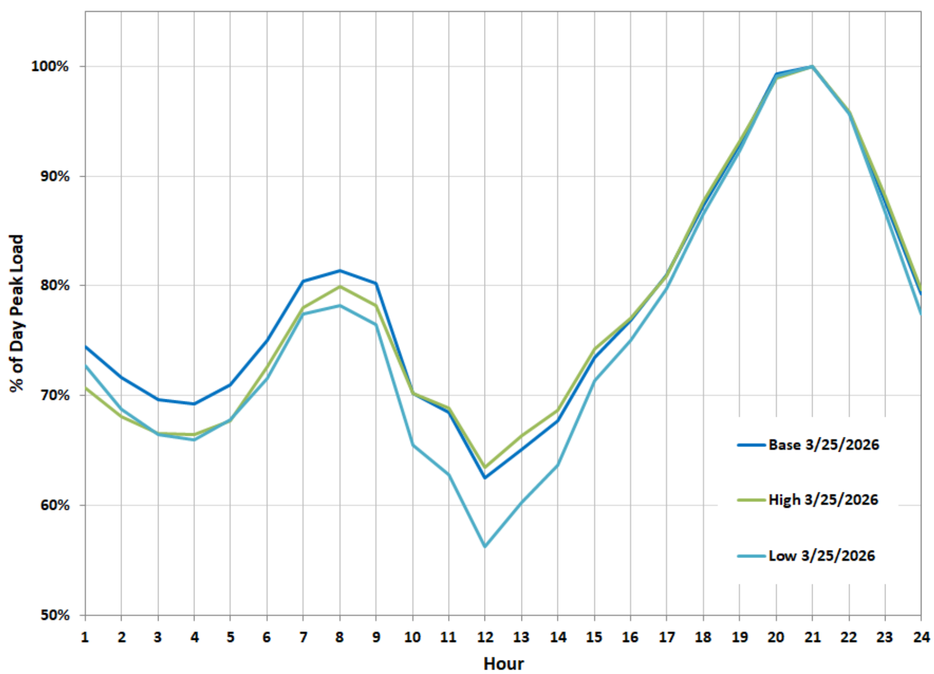
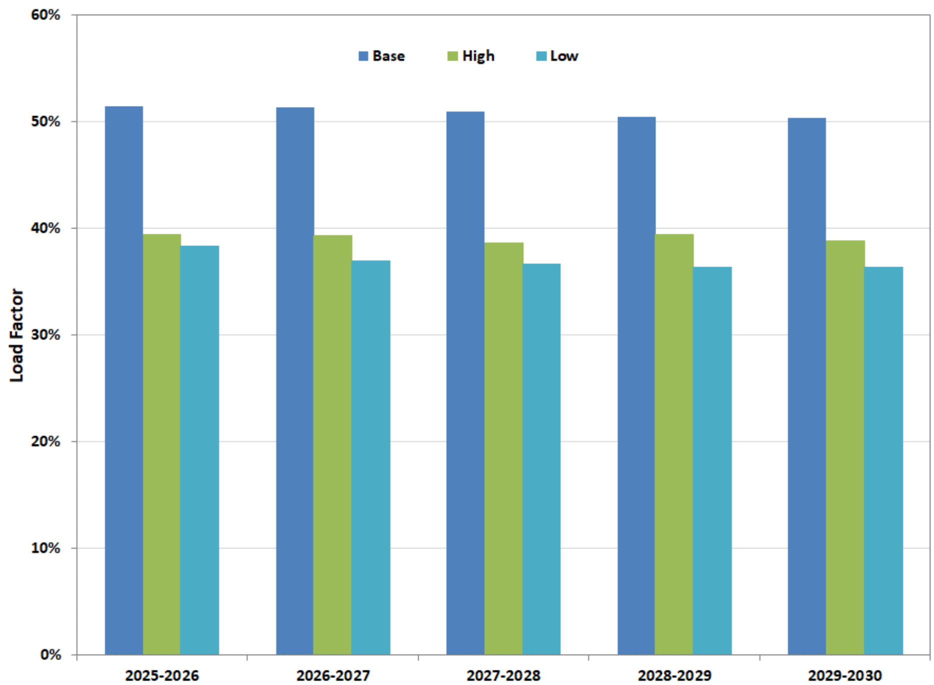


Figure 3-14: Sample Daily Load Shape, Spring Day in ComEd's Forecasts



The annual load factors are shown in Figure 3-15. As expected, the high load case has a lower load factor than the base case. Unexpectedly, the base case load factor is much higher than both the high-case and low-case load factors. This may indicate that the base case forecast was based on an average temperature pattern (normal every day).

Figure 3-15: Load Factor in ComEd's Forecasts



3.4 Summary of Information Provided by MidAmerican

In compliance with Section 16-111.5(d)(1) of the Public Utilities Act, MidAmerican provided the IPA the following documents for use in preparation of this plan:

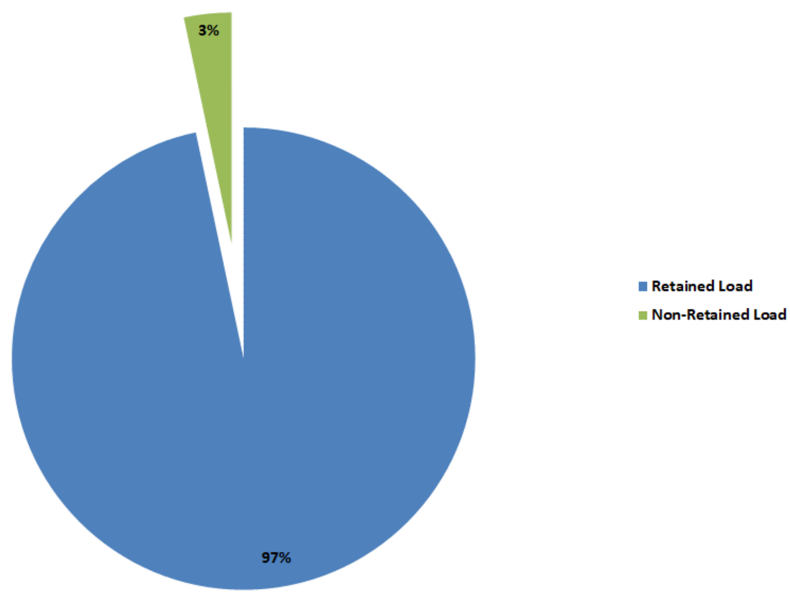
- *Methodology for the 2024 Plan Illinois Electric Customers and Sales Forecasts.* This document contained a discussion of load forecast methodology for all MidAmerican scenarios and supporting data for the base scenario forecast. The load forecast included a multi-year historical analysis of hourly load data, forecasted load and capability along with the impact of demand side and renewable energy initiatives. MidAmerican's load forecast was further broken down by revenue class, projected kWh usage and sales, which factored in economic and demographic variables along with weather variables based on weather data. Additionally, the load forecast accounted for sales forecasts based on variables and model statistics along with the non-coincident electric gross peak demand forecast and represents all of the eligible retail customer classes, except the customer being served by an ARES. MidAmerican methodology also includes the discussion of the energy efficiency and switching trends. Pursuant to Section 16-111.5(d)(1), MidAmerican's load forecast covered a five-year procurement planning period. (See Appendix D)
- Spreadsheets of load profiles, hourly load strips, procurement blocks, and scenario models for the base, high and low forecasts. (Summarized in Appendix G)

MidAmerican forecasts load by using econometric models on a monthly basis. For the residential, commercial and public authority classes, sales are determined by multiplying customers by use per customer. For the industrial class, sales are modeled directly. For the street lighting class, sales are forecast using trending.

The gross peak numbers used in the analysis are the historical gross peaks, which take into account demand side management impacts.

MidAmerican has one active alternative retail supplier in its Illinois service territory. MidAmerican has no customer classes that have been declared competitive. Figure 3-16 shows MidAmerican's retail load forecasted annual energy usage percentage. The low level of switching among MidAmerican's eligible retail customers relative to the much higher switching levels for Ameren Illinois and ComEd is likely due to a combination of market conditions in MidAmerican's service area, including the relatively low cost of MidAmerican-owned resources allocated to its Illinois load (which would lead to little or no municipal aggregation activity, and little profit opportunity for the ARES).

Figure 3-16: MidAmerican's Forecast Retail Customer Load Breakdown, Delivery Year 2025-2026[108]



MidAmerican provided a forecast of total usage for the entire service territory combining the projected customers and sales numbers modeled using data specific to the area being forecast. A suite of econometric models, adjusted for other considerations such as customer switching, is used to produce monthly usage forecasts. The hourly customer load models are applied to create hourly forecasts by customer class. Some variables, such as customer numbers, price, sales, revenue class, jurisdiction, etc., were obtained internally from the company database, while other data, such as economic, demographic and weather were received from external sources.

In determining the expected load requirements for which standard wholesale products will be procured, the MidAmerican forecast is adjusted for the volume served by the ARES. The MidAmerican 5-year annual load forecast, shown in Figure 3-17, incorporates the rate of customer switching in the past, and expected increases in the ARES service. The retail choice switching forecast was derived by reviewing recent switching activity and projecting forward recent trends. The figure breaks down the total forecast of the total retail customer load, in the same way as Figure 3-16 does for a single year.

[108] For the 2025-2026 Delivery Year, MidAmerican's projected total Retail Load is 1,926,118 MWh, where the Eligible Retained Load accounts for 1,863,101 MWh and the Eligible Non-retained Load accounts for 63,017 MWh. The amount for the projected total Retail Load was provided by MidAmerican in their July 2024 response to the IPA Data Request for the 2025 Long-Term Plan.

Figure 3-17: MidAmerican's Forecast Retail Customer Load by Delivery Year

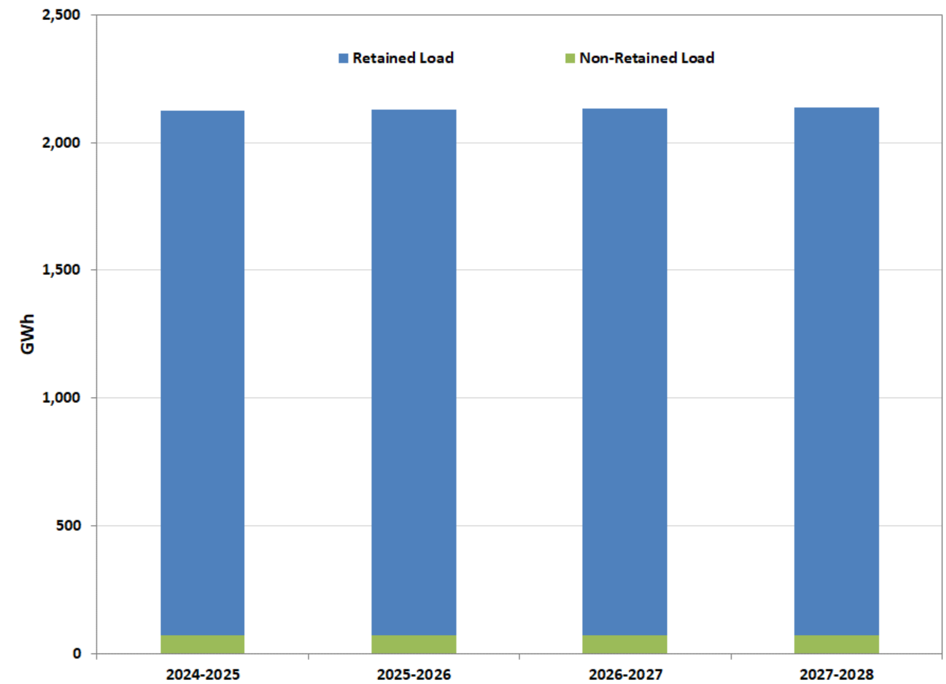
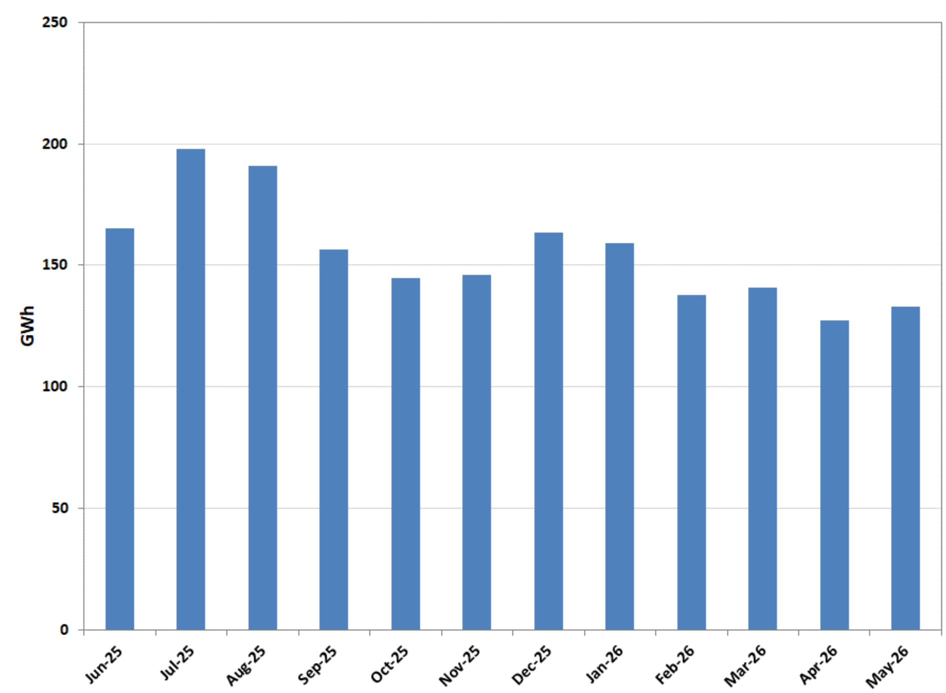


Figure 3-18 provides a monthly breakdown of the base case forecast of MidAmerican retained eligible retail customer load, that is, the load of customers on bundled supply to be considered under this Procurement Plan.

Figure 3-18: MidAmerican's Forecast Retained Eligible Retail Customer Load by Month



MidAmerican provided a Base-Case load forecast and two excursion cases: a Low-Case forecast and a High-Case forecast. The required low and high hourly load forecast scenarios were created by taking the 95% confidence interval around each class-level sales customer, and use per customer forecast, as well as the 95% confidence interval around the non-coincident gross peak demand forecast. The load forecasting software used for the sales, customer, use per customer, and non-coincident peak demand forecasts provided the upper and lower bounds of a 95% confidence interval around each monthly forecast value. This software feature allowed the construction of upper and lower bound forecasts for the residential, commercial, industrial and public authority sales forecasts. The street lighting sales forecast was multiplied by 0.99 and 1.01 to generate, respectively, a lower and upper bound street lighting sales forecast.

3.4.1 Macroeconomics

MidAmerican's Base Case load forecast utilized economic and demographic data that were obtained from IHS Markit, Inc. Data for other variables of the model, such as customer numbers, sales and other customer related data, were taken from internal company data sources. For MidAmerican's Illinois service territory, economic and demographic variables specific to the Quad Cities metropolitan area were used in the forecasting process. The Quad Cities area encompasses MidAmerican's Illinois service territory. The list of economic and demographic variables considered for the forecast includes real gross metropolitan area product, manufacturing, population, households, employment, etc. As mentioned above, MidAmerican used this model to define "high" and "low" cases applying the 95% confidence interval to arrive at the lower and upper bounds. The street lighting load was forecast using trending forecast techniques. In the customer revenue classes, the current customer numbers were assumed to remain constant while the corresponding energy sales were assumed to remain constant.

MidAmerican provided a June 2024 – May 2030 monthly expected load forecast, with a calculated annual growth rate of approximately -1.9%. This has fallen when compared to the June 2023 – May 2029 monthly expected load forecast of 0.22% provided in July 2023. MidAmerican noted there is projected to be a load reduction in Illinois that is due to 3M dropping an energy-intensive product line starting in 2025. See Section 3.5.1 for a discussion of how this load forecast compares to national trends in electricity load growth.

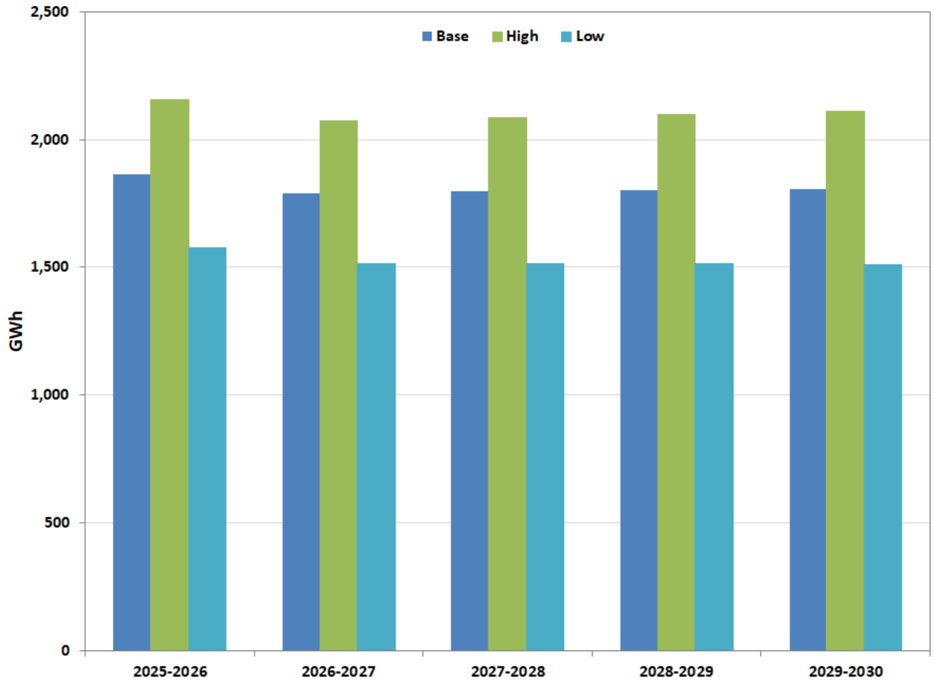
3.4.2 Weather

The Base Case temperature assumptions in the hourly load forecast model were not changed for the scenarios. The Base Case weather-related assumptions in the sales, the use per customer, and the non-coincident peak demand forecast models for MidAmerican's Illinois service territory were not changed in the scenarios.

3.4.3 Switching

The Base Case forecasts for retail switching sales, customers, and demand in MidAmerican Illinois service territory were not changed in the scenarios. Figure 3-19 shows MidAmerican's supply obligation in each case. As noted above, all three cases assume the Base Case assumptions for weather and switching, with the difference between the Base, High, and Low cases being attributable to macroeconomics (i.e., economic and demographic variables).

Figure 3-19: Supply Obligation in MidAmerican's Forecasts



3.4.4 Load Shape and Load Factor

Figure 3-20 and Figure 3-21 display the hourly profile of the utility supply obligation in each case (relative to the daily maximum load). Figure 3-20 illustrates a summer day, and Figure 3-21 shows a spring day. There is no meaningful difference between the base, low, and high load shapes on a sample summer day. During the sample spring day, the base case is peakier than the high case, and the low case is peakier than the base case.

Figure 3-20: Sample Daily Load Shape, Summer Day in MidAmerican's Forecasts

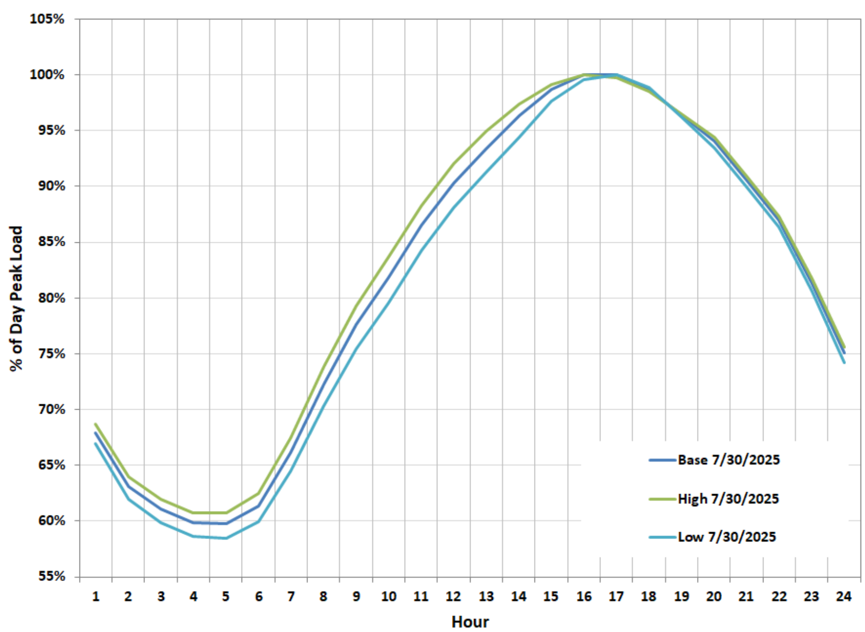
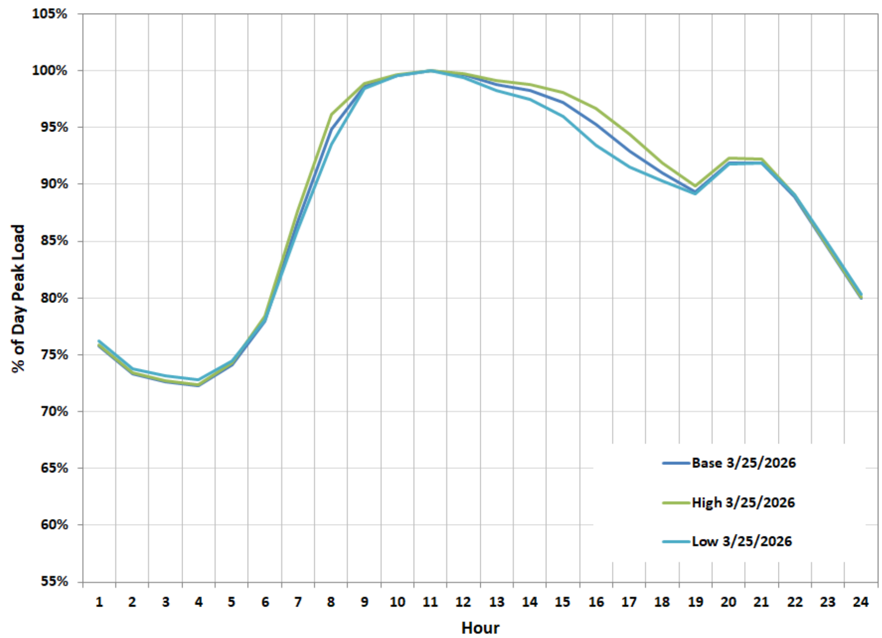
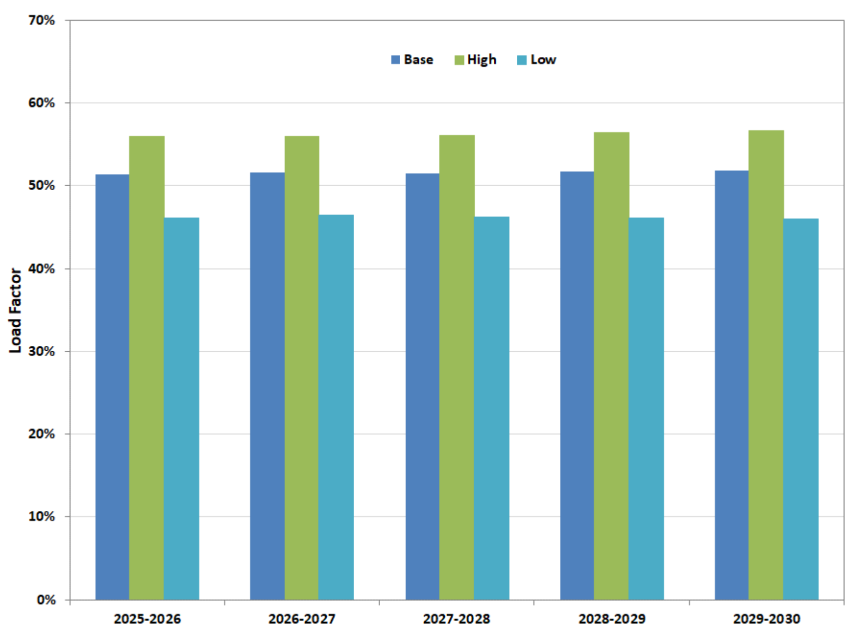


Figure 3-21: Sample Daily Load Shape, Spring Day in MidAmerican's Forecasts



The annual load factors are shown in Figure 3-22. As expected, the base, the high, and the low case load factors are consistent, being within the 46-57% range.

Figure 3-22: Load Factor in MidAmerican's Forecasts



3.5 Sources of Uncertainty in the Load Forecasts

In the past, the Agency has procured power for the utilities to meet a monthly forecast of the average hourly load in each of the on-peak and off-peak periods. The Agency has addressed the volatility in power prices by "laddering" its purchases: hedging a fraction of the forecast two years ahead, another fraction one year ahead, and a third fraction shortly before the beginning of the Delivery Year. Even if pricing two years ahead were extremely advantageous, the Agency does not purchase its entire forecast that far ahead because the forecast is itself uncertain. It is therefore important to understand the sources of uncertainty in the forecasts.

Furthermore, even if the Agency could perfectly forecast the average hourly load in each period, and perfectly hedge that forecast, it would still be exposed to power cost risk. Load varies from hour to hour. Energy in one hour is not a perfect substitute for energy in another hour because the hourly spot prices differ. A perfect hedge would cover differing amounts of load in different hours and would have to be based on a forecast of the different hourly loads. The "expected hourly load" is not an accurate forecast of each hour's load (see Section 3.5.3). This is not an issue of uncertainty; it would be true even if the expected hourly load were a perfect forecast of the average load, and the hourly profile (the ratio of each hour's load to the average) were known with certainty. As a result, it is treated here together with the other uncertainties.

3.5.1 Overall Load Growth

The demand for electricity across the U.S., as well as in the Midwest and Illinois specifically, has been flat to declining over the last decade. Recent trends (since 2023) are showing growth in 2024 over 2023, which is expected to continue in 2025 and beyond, although at slower rates as compared with the 2023 to 2024 growth. This growth is being driven nationally by increased demand for air conditioning, the rapid growth in highly electricity intensive data centers, and the growing number of electric vehicles. In the latest Short-Term Energy Outlook, the U.S. EIA predicts that total U.S. electricity consumption will increase by 3.08% from 2023 to 2024 and by 1.82% from 2024 to 2025.[109] By comparison, total electricity end use as reported by the EIA was essentially flat during the five-year ending 2023.[110] The U.S. Federal Energy Regulatory Commission in the 2024 Summer (June through September) Energy Market and Electric Reliability Assessment reported that it expected that most of the growth in total electricity consumption would result from data center demand.[111] This report shows that estimated U.S. data center power demand increased from 19 GW in 2023 to almost 21 GW in 2024. FERC also quoted a report that data center electricity demand would grow from 17 GW in 2022 to 35 GW in 2030, an average annual growth rate of 9.45%.[112] The growth in data center demand is expected to impact Illinois primarily in the PJM portion of the state with the Chicago area being characterized as among the primary data center markets in the U.S.[113]

While the 2023 utility load forecasts showed some growth in eligible retail load, in the near term (i.e., the next 4 years) eligible retail load in Illinois is not likely to be significantly affected by national trends. The base case utility load forecasts take into consideration the specific factors impacting load growth for their eligible retail customers including considering switching. As eligible retail customers are either residential or small commercial customers, the growth of demand from data centers, which are large commercial customers,[114] is not seen in these forecasts. For the residential electric customer class, Ameren Illinois currently projects a 5-year compound annual growth rate of -1.2%. This is a decrease from the 0.8% growth rate provided for the 2023 Plan. For commercial customers, the growth rate for Ameren Illinois is projected to be -1.2%. While for industrial customers, the growth rate for Ameren Illinois is projected to be 1.0%. ComEd provided a June 2025 – May 2030 monthly expected load forecast, with a calculated annual growth rate of approximately -0.38%. This has fallen when compared to the June 2024 – May 2029 monthly expected load forecast provided in July 2023, of 0.8%. However, the ComEd base case forecast shows a return to positive growth in the last year of the forecast. MidAmerican provided a June 2024 – May 2030 monthly expected load forecast, with a calculated annual growth rate of approximately -1.9%. This has fallen when compared to the June 2023 – May 2029

[109] U.S. Energy Information Administration Short-Term Energy Outlook July 2024. https://www.eia.gov/outlooks/steo/.

[110] U.S. EIA Total Energy Monthly Energy Review Table 7.6 Electricity End Use and Electric Vehicle Use. Total End Use. https://www.eia.gov/totalenergy/data/brows.

[111] See https://www.ferc.gov/news-events/news/report-2024-summer-energy-market-and-electric-reliability-assessment.

[112] NEWMARK, 2023 U.S. Data Center Market Overview & Market Cluster, (January 2024), https://www.newmark.com/insights/market-report/2023-u-s-data-center-market-overview-market-clusters.

[113] Data Center Frontier, Rapidly Growing Chicago Data Center Market's Tier 1 Expansion Is Persistent and Ongoing (Sept. 11, 2023), https://www.datacenterfrontier.com/site-selection/article/33011320/rapidly-growing-chicago-data-center-markets-tier-1-expansion-is-persistent-and-ongoing.

[114] See https://www.datacenterknowledge.com/energy-power-supply/data-center-power-fueling-the-digital-revolution for examples of the power consumption of typical data centers.

monthly expected load forecast provided in July 2023, of 0.22%. MidAmerican noted there is projected to be a load reduction in Illinois that is due to 3M dropping an energy-intensive product line starting in 2025.

The IPA will continue to monitor national load growth trends and the utilities' updated forecasts to determine if these trends are likely to impact eligible customer retail load growth in Illinois that would be addressed in future procurement plans.

Ameren Illinois and ComEd construct their load forecasts by forecasting load for their entire delivery service area, then forecasting the load for each customer class or rate class within the service territory, and then applying multipliers to eliminate load that has switched to municipal aggregation or other ARES service. Customer groups that have been declared competitive – medium and large commercial and industrial customers – are removed entirely, as the utilities have no supply or planning obligation for them. In contrast, MidAmerican, a utility serving a much smaller number of electric customers in Illinois territory, does not have any customer classes that have been declared competitive. There is only one entity providing ARES service in the MidAmerican Illinois service territory serving a relatively small segment of customers. Similar to the other two utilities, MidAmerican constructs its load forecast by using a top-to-bottom approach.

Ameren Illinois does not explicitly address uncertainty in load growth. In other words, Ameren Illinois does not define "load growth scenarios" and examine the consequences of high or low load growth. Ameren Illinois addresses both load and weather uncertainty by defining high and low scenarios at particular confidence levels of the model fit, that is, of the residuals of its econometric model. The high and low cases, which represent the combined and correlated impact of weather and load growth uncertainties, represent a variation of only ±7% in service area load. However, Ameren Illinois' high and low cases also include extreme customer migration uncertainty.

ComEd defines high and low load growth scenarios as 2% above or below the load growth in the base case forecast. The changes in load growth are imposed upon the model rather than derived from economic scenarios, so it is hard to determine how they relate to economic uncertainty. Given the stability of utility loads in recent years, differences of ±2% in load growth should provide an appropriately representative range of uncertainty.

Like Ameren Illinois, MidAmerican addresses the load and weather uncertainty by defining high and low scenarios at particular confidence levels, i.e., by applying the 95% confidence interval around reference sales, customer and use per customer forecasts, and the non-coincident gross peak demand forecast. The street lighting sales forecast, however, was multiplied by 0.99 and 1.01 to generate, respectively, a lower and upper bound of street lighting sales forecast, which is more similar to the ComEd's approach.

3.5.2 Weather

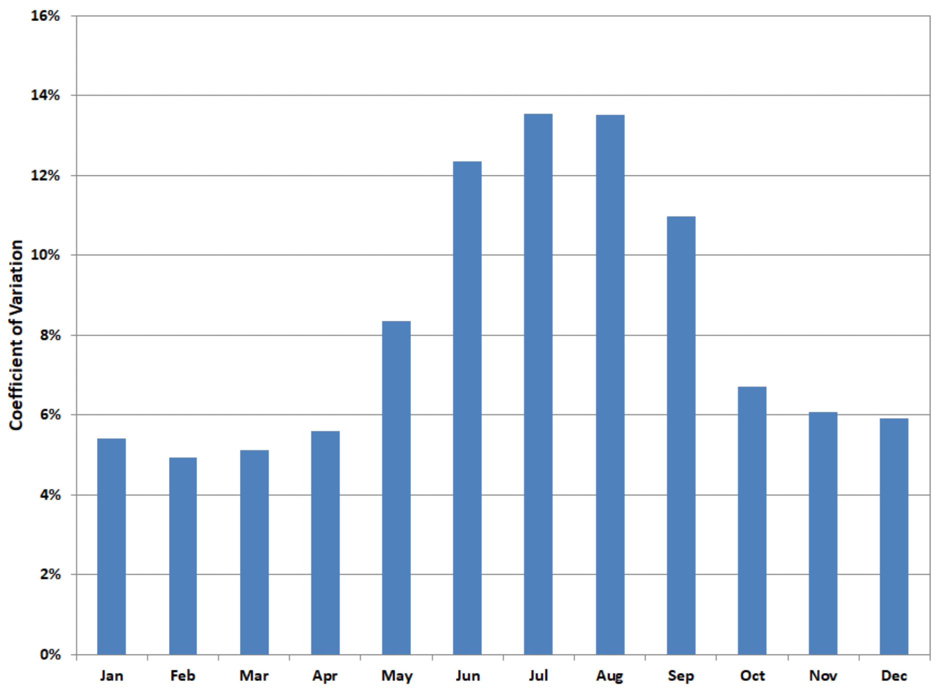
On a short-term basis, weather fluctuations are a key driver of the uncertainty in load forecasts, and in the daily variation of load forecasts around an average-day forecast. The discussion of high and low scenarios in Sections 3.2.2, 3.3.2, and 3.4.2 notes the way that Ameren Illinois, ComEd, and MidAmerican have incorporated weather variation into the high and low load forecasts. Ameren Illinois treats weather uncertainty together with load growth uncertainty. ComEd's forecasts are built around two sample years. Much of the impact of weather is on load variability within the year. MidAmerican's base case weather-related assumptions are not changed for the high-case and low-case load forecasts. The base-case load forecast is built on the "weather normalized" historical sales.

3.5.3 Load Profiles

As noted above, the "average hour" load forecast is not an accurate forecast of each hour's load. Within the sixteen-hour daily peak period, mid-afternoon hours would be expected to have higher loads than average, and early morning or evening hours would be expected to have lower loads. More importantly, multiplying the average hourly load by the cost of a "strip" contract (equal delivery in each hour of the period) gives an inaccurate forecast of the cost of energy. This is because hourly energy prices are correlated with hourly loads (energy costs more when demand is high). Technically, this is referred to as a "biased" forecast, because the expected cost will predictably differ from the product of the "average hour" load forecast and the "strip" contract price.

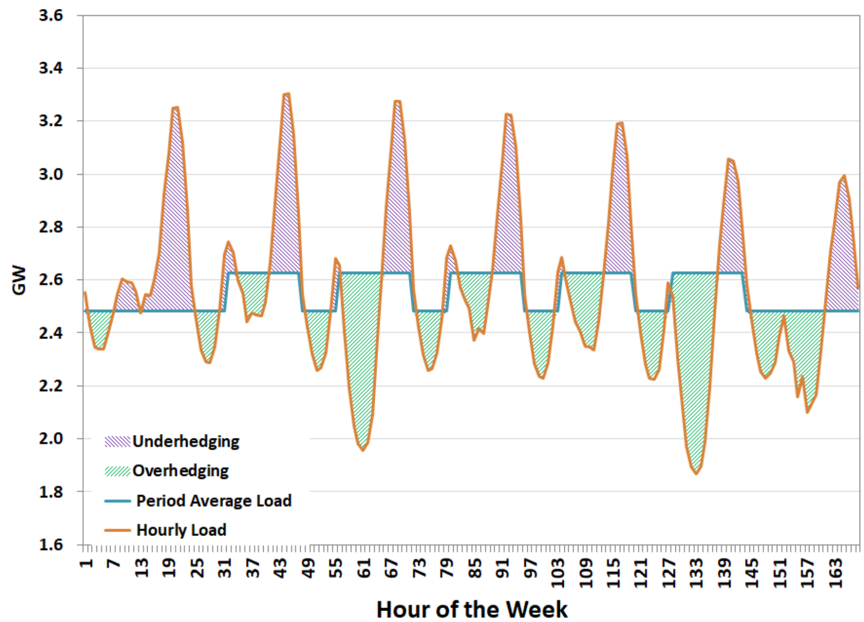
Figure 3-23 illustrates this disconnect by showing, for each month, the average historical "daily coefficient of variation" for peak period loads. This figure is based on historical ComEd loads from 2009 through 2023, normalized to the monthly base case forecasts in the first Delivery Year. To calculate the daily coefficient of variation, the variances of loads within each day's peak period are averaged to produce an expected daily variance. That variance is then scaled to load by first taking the square root and then dividing by the average peak-period hourly load forecasted for the month. As the figure shows, there is significant load variation during the day in the high-priced summer months.

Figure 3-23: Coefficient of Variation of Daily Peak-Period Loads



Because of this variation, even if the average peak and off-peak monthly load is perfectly hedged, the actual hourly load will still be imperfectly hedged. In other words, if the Agency were to buy peak and off-peak hedges whose volumes equaled respectively the average peak period load and average off-peak period load, there would still be unhedged load because the actual load is usually greater or less than the average. This is illustrated in Figure 3-24, below.

Figure 3-24: Example of Over- and Under-Hedging of Hourly Load



3.5.4 Municipal Aggregation and Individual Switching

In its base case, Ameren Illinois projects that approximately 54% of potentially eligible retail customer load[115] will have switched away from Ameren Illinois default fixed price tariff service by the end of the 2024-2025 Delivery Year. This is higher than the 45% switching statistics in the July 2023 forecasts.

Ameren expects that the communities will renew their agreements with the ARES, and AIC will see a similar rate of individual opt-out within these communities.[116] Ameren Illinois' current default service price is lower than comparable ARES prices for individual customers (as shown in Table 3-2 below), which may result in some individual customers opting to return to utility service. ComEd projects that 35% of potentially-eligible retail load will have switched to ARES service by the end of the 2025-2026 Delivery Year, which exceeds the 31% switching rate assumed in the July 2023 forecasts. Both Ameren Illinois and ComEd have assumed a wide range of switching fractions in the low and high scenarios (return to utility service would be represented as a decrease in the switching fraction over time).

In addition to offers to customers made through municipal aggregation programs, ARES offer a variety of products directly to customers – some of which have a similar structure to the utility bundled service, while others vary significantly in structure. These include offers with pass-through capacity prices, "green" energy above the mandated RPS level (typically at a premium price), month-to-month variable pricing (frequently with an initial rate lower than utility service, but no guarantee of that lower price being maintained after an initial period), longer-term fixed prices, options to match prices in the future, options to extended contract terms, and options to adjust prices retroactively.[117] Individual customers who choose one of these other rate structures presumably have made an affirmative choice to take on those alternative services.

Although switching from default service to an ARES by individual customers has some impact on overall customer switching trends, Ameren Illinois and ComEd switching forecasts have been dominated by municipal aggregation. While the IPA recognizes that many ARES focus on individual residential switching, the IPA is not

[115] "Potentially-eligible retail customer load" refers to the load of those customers eligible to take bundled service from the utility.

[116] In March 2024 AIC developed three energy forecasts that assume that these communities will renew their agreements with the ARES, and AIC will see a similar rate of individual opt-out within these communities. As such, the forecasts do not contain a switching scenario where load leaves or returns to AIC's fixed price supply due to the expiration of municipal aggregation agreements.

[117] For more information on choices offered by ARES, see the July 2024 Annual Report of the ICC Office of Retail Market Development at https://icc.illinois.gov/api/web-management/documents/downloads/public/icc-reports/2024%20ORMD%20Section%2020-110%20Report.pdf .

aware of a significant number of residential customers leaving default service to take ARES service outside of a municipal aggregation program. As shown in Table 3-2, this is currently the case because of the appreciable difference between the utility price to compare and representative ARES prices available to eligible utility customers.[118] It appears that, currently, ARES fixed price offers for a 12-month term are higher than the respective utility summer rates and do not appear to offer savings to individual residential customers.[119] It is reasonable to assume that switching behavior by individual customers (other than those who chose an ARES rate that is not an "apples-to-apples" comparison to the utility rate, or one that offers additional perceived value) will not be a significant factor in the load forecast, except for transition to municipal aggregation, opt-out from municipal aggregation, and return from municipal aggregation. The ARES offer currently applicable to MidAmerican's service territory is a variable rate which is not comparable to the utility's price.

Table 3-2: Representative ARES Fixed Price Offers and Utility Price to Compare[120]

Utility Territory	Utility Price to Compare (¢/kWh)	Representative ARES Price (¢/kWh)
Ameren Illinois (Rate Zone I)	8.14	10.53
Ameren Illinois (Rate Zone II)	8.14	10.50
Ameren Illinois (Rate Zone III)	8.14	10.74
ComEd	6.90	8.42

3.5.5 Hourly Billed Customers

Customers who could have elected fixed-price bundled utility service but take electric supply pursuant to an hourly pricing tariff are not "eligible retail customers" as defined in Section 16-111.5 of the PUA. Therefore, these hourly rate customers are not part of the utilities' supply portfolio for purposes of this procurement planning process, and the IPA does not procure energy for them. Ameren Illinois and ComEd did not include customers on hourly pricing in their load forecasts; they appropriately considered these customers to have switched. The amount of load on hourly pricing is small and unlikely to undergo large changes that would introduce significant uncertainty into the load forecasts. MidAmerican does not have hourly billed customers.

3.5.6 Energy Efficiency

Public Act 95-0481 created a requirement for ComEd and Ameren Illinois to offer cost-effective energy efficiency and demand response measures to all customers,[121] with updates to those savings targets adopted through Public Act 99-0906. Both Ameren Illinois and ComEd have incorporated into their forecasts the expected impacts of these updated measures (as applied to eligible retail customer load).

MidAmerican offers energy efficiency programs pursuant to a separate provision of the Public Utilities Act found in Section 8-408. In submitting its load forecast, MidAmerican stated that estimated past energy savings are implicit in the historical data used to derive the electric sales forecast models. Without adjustment, this method implies that the level of future estimated program savings will be similar to past estimated program savings. Estimated program impacts in the forecast period are not projected to deviate measurably from estimated historical levels, so no adjustment was made to the forecasting models.

[118] Representative ARES prices are an average of 12-month fixed price offers from ARES available at https://www.pluginillinois.org/OffersBegin.aspx. The utility Price to Compare is exclusive of the Purchased Electricity Adjustment, which as discussed in Section 6.5 has been a consistent credit in recent years for Ameren Illinois and ComEd customers. Therefore, the difference shown may be understated.

[119] Based on the price data in Table 3-2, Ameren Illinois retail customers taking a representative fixed-price supply service offer from an ARES in September 2023 would pay approximately 30.1% more than if they were to take default supply service from the utility. ComEd retail customers would pay approximately 21.9% more.

[120] The values in the table are as of July 24, 2024. Offers without an explicit premium renewable component. Monthly service fees and early termination fees are not included in rates.

[121] See P.A. 95-0481 (Section originally codified as 220 ILCS 5/12-103).

3.5.7 Demand Response

As noted by the utilities in their load forecast documentation, demand response does not impact the weather-normalized load forecasts. As such, the IPA notes that demand response operates more like supply resources. Section 7.4 of the Plan contains the IPA's discussion and recommendations for demand response resources.

3.5.8 Emerging Technologies

An emerging technology that could have a significant impact on the Illinois power market as well as the IPA's future procurement plans is energy storage—in particular, lithium-ion ("Li-ion") battery storage integrated with solar PV distributed generation. Based on storage data compiled by the U.S. Department of Energy, as of July 2024, there were 67 operational utility scale battery-based storage systems with a total capacity of 415 MW operating in PJM and 35 systems totaling 84.7 MW operating in MISO. Illinois was listed as having 13 utility scale projects with 117.6 MW in operation and 6 utility scale projects with 220.0 MW proposed and under construction.[122] The overwhelming majority of these projects are based on Li-ion chemistry.

While utility scale energy storage technology continues to be developed and deployed, distributed solar PV integrated with distributed storage offers significant potential to enhance the benefits and spur the development of solar distributed generation. However, the costs of Li-ion batteries for use with distributed solar PV systems (such as residential rooftop solar) remain high relative to the value proposition for residential and small commercial solar PV applications, even with the average cost of battery storage declining by 89% from 2008 to 2022113[123] and are now expected to fall by an average of 11% per year from 2023 to 2030.[124] While the average cost of battery storage using Li-ion batteries is forecast to continue to decline it is too early to forecast the impact on load forecasts associated with distributed solar PV integrated with battery storage.

The Agency notes that while Public Act 99-0906 encouraged the development of distributed solar PV, there were clear provisions in Illinois law to encourage the adoption of integrated storage technologies prior to the enactment of Public Act 102-0662 on September 15, 2021. Public Act 102-0662 includes several provisions encouraging the development of integrated energy storage in Illinois, including storage co-located at shuttered coal plant sites alongside new utility-scale solar projects,[125] rebates for energy storage systems,[126] and mandating a study of policies and programs that could support energy storage systems.[127] Multiple proposals in the Spring 2024 session of the 103rd General Assembly sought for the IPA to develop an energy storage procurement plan and procure energy storage credits to support the development of new energy storage projects, although no such bills passed. The Agency will continue to monitor the development of the energy storage market in the coming years and monitor developments on energy storage legislation in the Illinois General Assembly.

3.5.9 COVID-19 Impacts on Utilities' Load Forecasts

In reviewing the load forecast documentation, ComEd and MidAmerican briefly mention that they have included consideration of the impacts of COVID-19 in their forecasts. ComEd states that COVID has impacted load at the home and adjusted the forecast methodology to account for changes in load due to the pandemic. ComEd included new independent variables within the traditional models used in filings before 2020 which estimate the GWh impact by customer class from dynamics like social distancing, mandated business closures, and remote work. ComEd has noted that with no significant changes in pandemic statistics in the last two years, these variables do not have a significant impact over the forecast period.

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[122] The summary values were calculated by reviewing the following two databases: 1) U.S. Department of Energy 2023 Form EIA-860 Data - Schedule 3, 'Energy Storage Data', https://www.eia.gov/electricity/data/eia860/, release date 6/12/2024 and 2) https://sandia.gov/ess-ssl/gesdb/public/, queried in July 2023. Duplicate projects identified across the two databases were removed from the totals.

[123] Electric Vehicle Battery Pack Costs in 2022 Are Nearly 90% Lower than in 2008, according to DOE Estimates, January 9, 2023

https://www.energy.gov/eere/vehicles/articles/fotw-1272-january-9-2023-electric-vehicle-battery-pack-costs-2022-are-nearly#:~:text=The%20Department%20of%20Energy's%20(DOE's,least%20100%2C000%20units%20per%20year.

[124] https://www.goldmansachs.com/intelligence/pages/electric-vehicle-battery-prices-falling.html.

[125] See 20 ILCS 3855/1-75(c-5).

[126] See 220 ILCS 5/16-107.6(b-5) and (c).

[127] See: 220 ILCS 5/16-135.

3.6 Recommended Load Forecasts

3.6.1 Base Cases

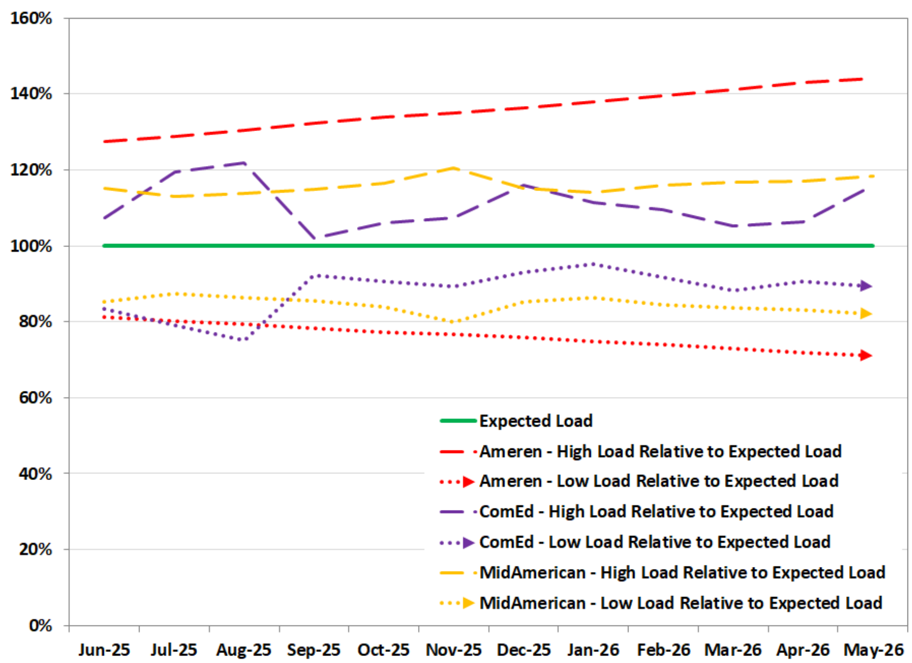
The IPA recommends adoption of the Ameren Illinois, ComEd, and MidAmerican base case load forecasts.[128] The Ameren Illinois and ComEd forecasts include already approved energy efficiency programs, and MidAmerican's forecast includes verified energy efficiency program impacts as well.

3.6.2 High and Low Excursion Cases

The high and low cases represent useful examples of potential load variability. Although they are primarily driven by variation in switching, Ameren Illinois correctly notes that this is the major uncertainty in its outlook. The switching variability, especially in Ameren Illinois' high and low forecasts, is extreme and thus these may be characterized as "stress cases." The Agency's procurement strategy to date has been built on hedging the expected average hourly load in each of the peak and off-peak sub-periods, and the high and low cases represent significant variation in those averages.

As illustrated in Figure 3-25, the Ameren Illinois low and high load forecasts are on average equal to 76% and 136% of the base case forecast, respectively, during the 2025-2026 Delivery Year. Comparatively, for the same period, ComEd's low and high load forecasts are on average equal to 88% and 111% of the base forecast, respectively. This reflects the differences in switching assumptions used by the two utilities. MidAmerican's low and high load forecast deviations from the base case are flat and symmetrical being equal to 84% and 116%, respectively. The reference case forecasts for retail switching were not changed in Mid American's high and low load forecasts.

Figure 3-25: Comparison of Ameren Illinois, ComEd, and MidAmerican High and Low Load Forecasts for Delivery Year 2025-2026



Another potential use of the high and low cases would be to analyze the risks of different supply strategies. A key driver of that risk is the cost of meeting unhedged load on the spot market. One of the main reasons is the disparity between load and the selected hedging instrument. As in Figure 3-24, load is variable while the hedging instrument (standard block energy) features a constant delivery of energy. The spot price at which the

[128] As discussed in Footnote 116, the Agency also adopts Ameren Illinois' mid scenario of switching related to municipal aggregation contained within the base case load forecast.

unhedged volumes are covered is positively correlated with load. However, as explained below, the high and low cases are less suitable for such a risk analysis.

The relatively high load factor of the ComEd base case forecast implies that the hourly profile of that case is not representative of a typical year. This means that the base case hourly forecast would understate the amount by which hourly loads vary from the average hourly loads in the peak and off-peak sub-periods. Using that hourly profile for a risk analysis could lead to underestimating the cost of unhedged supply.

The Ameren Illinois and MidAmerican load scenarios have identical monthly load shapes (differing by uniform scaling factors). These shapes will not provide much information about the cost of meeting fluctuating loads, except for the information contained in the expected load shape.

The extreme nature of the Ameren Illinois low and high load forecasts can influence the results of a probabilistic risk analysis. With almost any assignment of weights to the Ameren Illinois cases, load uncertainty will dominate price uncertainty. This does not apply to ComEd and MidAmerican, which must be taken into account when evaluating any simulation of procurement risk.

4 Existing Resource Portfolio and Supply Gap

Starting with the 2014 Procurement Plan, the IPA has procured energy supply in standard 25 MW on-peak and off-peak blocks. This energy block size was reduced from the previous level of 50 MW to more accurately match procured supply with eligible retail customer load.[129] These purchases are driven by the supply requirements outlined in the current year procurement plan and are executed through a competitive procurement process administered by the IPA's Procurement Administrator. This procurement process is monitored for the Commission by the Commission-retained Procurement Monitor. The history of the IPA-administered procurements is available on the IPA website.[130]

The 2024 Procurement Plan targeted the procurement of energy supply to meet the needs of ComEd's and Ameren Illinois' eligible retail customers, as well as that portion of MidAmerican's eligible retail customer load not met through its allocation of existing generation. The 2025 Procurement Plan will continue to target the procurement of energy supply to meet the needs of eligible retail customers for each of the three utilities.

In addition to purchasing energy block contracts in the forward markets, Ameren Illinois, MidAmerican, and ComEd rely on the operation of their RTOs (MISO and PJM) to balance their loads and consequently may incur additional costs or credits. Purchased energy blocks may not perfectly cover the load, therefore triggering the need for spot energy purchases or sales from or to the RTO wholesale market. The IPA's procurement plans are based on a supply strategy designed, among other things, to balance price risk and cost. The underlying principle of this supply strategy is to procure energy products that will cover all or most of the near-term load requirements and then gradually decrease the amount of energy purchased relative to load for the following years.

The 2024 Procurement Plan's energy procurement strategy involved procurement of hedges to meet a portion of the hedging requirements over a three-year period and included two procurement events in which the July and August peak requirements were targeted to be hedged at 106% for Ameren Illinois and MidAmerican, while the remaining peak and off-peak requirements were targeted to be hedged at 100% for Ameren Illinois and MidAmerican. The Commission's Final Order approving the 2023 Plan reduced the hedging target for ComEd's eligible customers to 50% in recognition of the value that Carbon Mitigation Credits can provide to eligible retail customers in offsetting energy price changes. Another change implemented for the 2023 Plan was hedging a greater portion of the immediate summer months' load prior to the Spring procurement so that the volumes to be procured for the prompt summer months would be reduced in the immediately prior Spring procurement event. This change reduces the impact that a seasonal price spike (as occurred in 2022) would have on summer month procurements. The changes implemented for the 2023 and 2024 Plans will continue for the 2025 Plan.

In response to FERC's decision on August 31, 2022, approving revisions to the Midcontinent Independent System Operator, Inc. ("MISO") Open Access Transmission, Energy and Operating Reserve Markets Tariff, MISO established a seasonal resource adequacy construct. Following MISO's implementation of this seasonal capacity construct in the 2023-2024 Delivery Year, the Agency held its third and fourth capacity events to procure seasonal Zonal Resource Credits ("ZRCs") in the Fall 2023 Capacity Procurement and the Spring 2024 Capacity Procurement, respectively.

For Ameren Illinois and MidAmerican, this Plan maintains the 106% hedging target for July and August on-peak to mitigate the impact of shaping risk, which due to the correlation between load and price, results in load-weighted prices during peak hours being greater than time-weighted prices. In the risk analysis conducted for the 2014 Plan, the IPA determined that load shape and its correlation with prices adds approximately 6% to the average cost of energy supply. For Ameren Illinois and MidAmerican, the IPA will continue its current energy procurement strategy for July and August which involves procurement of on-peak hedges at 106% and off-peak at 100%. Following the 2024 Plan, for this Plan the Agency will continue to shift the procurement volume for the summer months in the prompt Spring procurement from approximately 50% to 25% by increasing procurement volumes in prior procurements. Based on the Commission's Order approving the 2023 and 2024 Plans, the IPA will maintain the hedging targets for ComEd of 50% through the 2026-2027 delivery

[129] See 2014 IPA Procurement Plan at 93.

[130] https://ipa.illinois.gov/energy-procurement/prior-approved-plans.html.

year for all months to recognize the value that Carbon Mitigation Credits can provide to eligible retail customers in offsetting energy price fluctuations. Because Carbon Mitigation Credit contracts end after the 2026-2027 delivery year, procurement targets for ComEd for the third year of procurement (the 2027-2028 delivery year) will return to a level designed to hedge to 100% (and 106% on-peak for July and August) at the conclusion of the three-year cycle of procurements.

Additionally, the IPA will continue its current energy procurement strategy to meet the hedging requirements over a three-year period and includes two procurement events each year, one in the spring and the second in the fall. Percentage and quantity targets for each procurement event in 2025 are specified in Section 7.1 of this Plan.

Because of the uncertainty in the amount of eligible retail customer load in future years, the IPA has not purchased energy beyond a 3-year horizon, except in a few circumstances. These include:

- 20-year bundled REC and energy purchases (also known as the 2010 long-term power purchase agreements or "LTPPAs"), starting in June 2012, made by Ameren Illinois and ComEd in December 2010 pursuant to the Final Order in Docket No. 09-0373.[131]
- The February 2012 "Rate Stability" procurements mandated by Public Act 97-0616 for block energy products covering the period June 2013 through December 2017.[132]
- The discussion below explores in more detail the supply gap between the updated utility load projections described in Chapter 3 and the supply already under contract for the planning horizon. The IPA's approach to addressing these gaps is described in Chapter 7.

4.1 Ameren Illinois Resource Portfolio

Figure 4-1 shows the current supply gap in the Ameren Illinois supply portfolio for the five-year, June 2025 through May 2030, planning period, using the base case on-peak forecast described in Chapter 3.

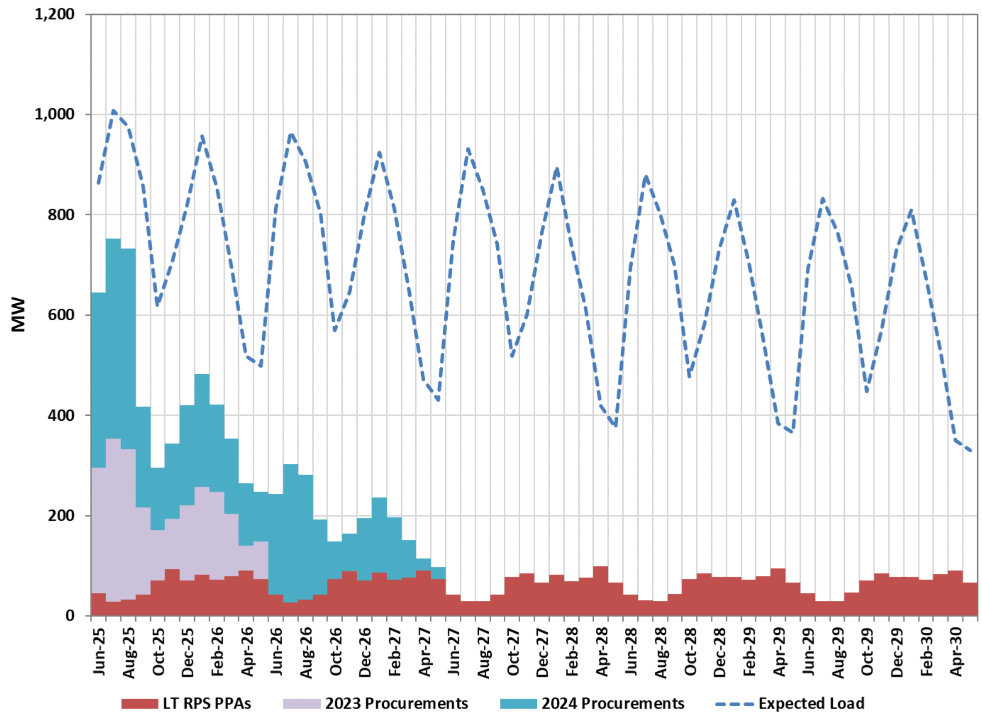
Ameren Illinois' existing supply portfolio, including long-term renewable energy resource contracts, is not sufficient to cover the projected load for the 2025-2026 Delivery Year. Additional energy supply will be required for the entire 5-year planning period. As of April 2023, Ameren Illinois was serving approximately 57% of its eligible load. However, in response to recent volatile pricing and market conditions, the utility is forecasting a switching percentage of approximately 45% in its load forecast which is discussed in Chapter 3. The Ameren Illinois base case scenario load forecast assumes that switching will be flat across the current planning horizon.

Quantities shown are average peak period MW for both loads and historic purchases.

[131] With the changes to the Renewable Resources Budget contained in P.A. 99-0906, curtailment of the Ameren Illinois and ComEd LTPPAs (as occurred for ComEd in 2013 and 2014) is extremely unlikely. MidAmerican is not a counterparty to the LTPPAs.

[132] P.A. 97-0616 also mandated associated REC procurements, but these REC procurements did not impact the (energy) resource portfolio. Additionally, twenty-year power purchase agreements between Ameren Illinois and ComEd and the FutureGen Industrial Alliance, Inc. were directed by the Commission order approving the Agency's 2013 Procurement Plan. (See Docket No. 12-0544) However, U.S. DOE funding support for FutureGen 2.0 was suspended, and in early 2016, the project's development was ultimately terminated.

Figure 4-1: Ameren Illinois' On-Peak Supply Gap - June 2025-May 2030 Period - Base Case Load Forecast

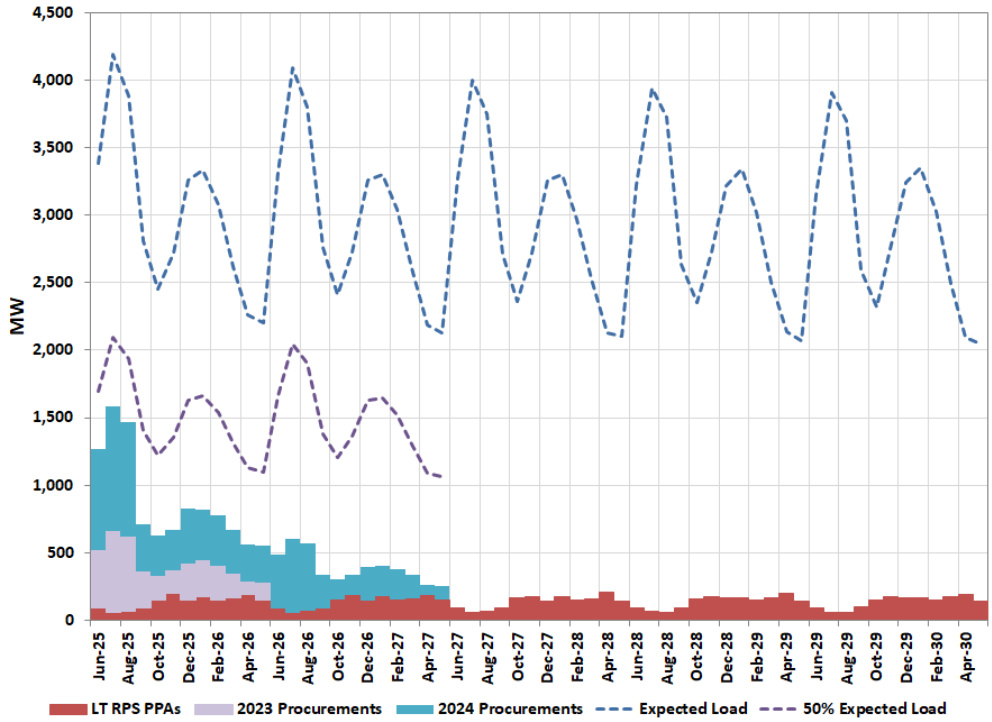


Under the base case load forecast scenario, the average supply gap for peak hours of the 2025-2026 Delivery Year is estimated to be 333 MW, the peak period average supply gap for the 2026-2027 Delivery Year is estimated to be 362 MW, and the average peak period supply gap for the 2027-2028 Delivery Year is estimated to be 396 MW. While the planning period is five years, the IPA's hedging strategy is focused on procuring electricity supplies for the immediate three Delivery Years.

4.2 ComEd Resource Portfolio

Figure 4-2 shows the current gap in the ComEd supply portfolio for the June 2025-May 2030 planning period, using the base case load on-peak forecast described in Chapter 3. Note that through May 2027, this Plan seeks to hedge 50% of ComEd Expected Load due to the offsetting value created by Carbon Mitigation Credit Contracts (See Section 6.9). As of May 2023, approximately 54.8% of total usage in ComEd's 0 to 100 kW class was served by retail electric suppliers.

Figure 4-2: ComEd's On-Peak Supply Gap - June 2025-May 2030 period - Base Case Load Forecast



As with Ameren Illinois, ComEd's current energy resources will not cover eligible retail customer load starting in June 2025. The average supply gap during peak hours for the 2025-2026 Delivery Year under the base case load forecast is estimated to be 2,139 MW. The average supply gap during peak hours for the 2026-2027 and 2027-2028 Delivery Years is estimated to be 2,577 MW and 2,792 MW respectively.

4.3 MidAmerican Resource Portfolio

MidAmerican has requested that the IPA procure electricity for the incremental load that is not forecasted to be supplied in Illinois by MidAmerican's Illinois jurisdictional generation including an allocation of generating capacity from its generating facilities located in Iowa ("Illinois Historical Resources").

MidAmerican revised the methodology used for its generation supply forecast starting with the forecast information submitted for the 2019 Plan. The prior forecast methodology utilized production cost models to dispatch the Illinois Historical Resources whenever the expected cost to generate electricity is less than the expected cost of acquiring it in the market. The revised methodology is based on the utilization of MISO Unforced Capacity ("UCAP") from the baseload Illinois Historical Resources to determine the generation available to meet MidAmerican's Illinois eligible load.[133]

MidAmerican's revised methodology utilizes the full capability of each baseload generation asset, represented by the UCAP MW values as determined by MISO for each year's Planning Resource Auction. The UCAP values de-rate generating unit capabilities by considering historical forced outage rates and operating conditions under summer peak conditions. This methodology was utilized for the 2020, 2021, 2022, 2023, 2024 Plans. The IPA, for the 2025 Plan, recommends no changes to the determination of monthly on-peak and off-peak block energy requirements. MidAmerican's generation supply forecast is based on the UCAP values for each of the following baseload resources:

- Coal resources including: Neal Unit #3, Neal Unit #4, Walter Scott Unit #3, Louisa Generating Station, and Ottumwa Generating Station.
- Nuclear Resources: Quad Cities Nuclear Power Station.

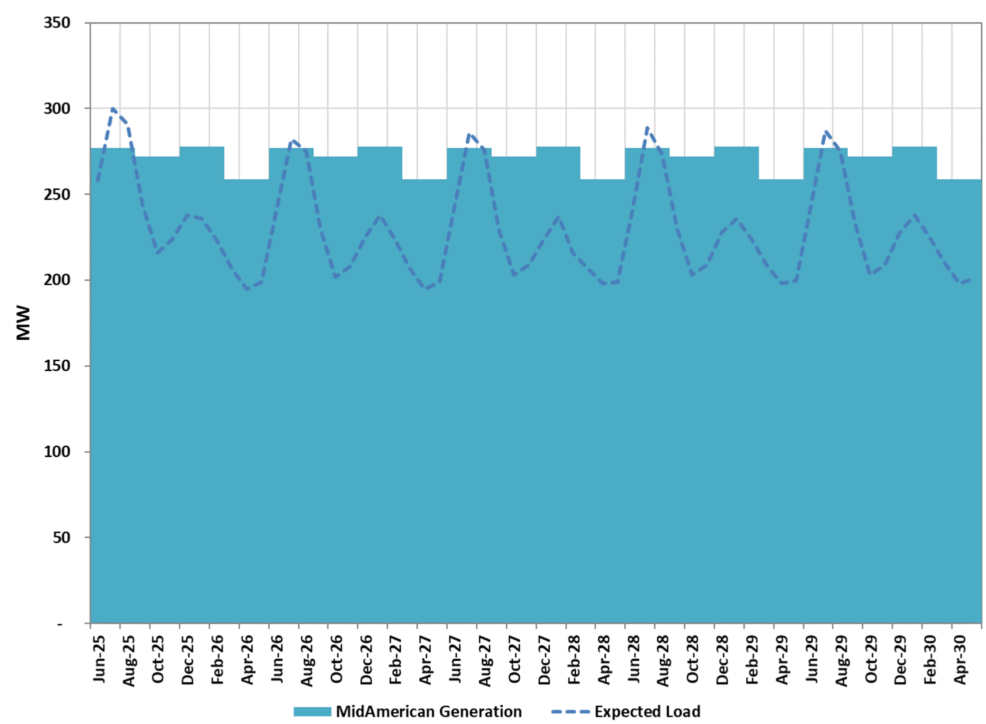
[133] MidAmerican allocates 10.86% of the UCAP ratings of its baseload units for Illinois Historical Generation.

The supply capability that is determined is netted against the forecast of MidAmerican Illinois load to calculate the monthly on-peak and off-peak shortfalls which will be met with energy block purchases in the IPA procurements. In determining the amount of block energy products to be procured for MidAmerican, the IPA treats the allocation of capacity and energy from MidAmerican's Illinois Historical Resources in a manner analogous to a series of standard energy blocks. This approach is consistent with the 2024 Procurement Plan approved by the Commission.

The IPA believes that the methodology used with regards to MidAmerican's supply procurement is reasonable and that the overall hedging levels and laddered procurement approach are consistent with the proposed approach for Ameren Illinois and ComEd. The IPA and MidAmerican will continue to monitor the actual performance of this approach and will revisit it in future procurement plans, if warranted.

Figure 4-3 shows the current supply gap in the MidAmerican supply portfolio for the five-year planning period, using MidAmerican's base case on-peak load forecast. The average supply surplus during peak hours for the 2025-2026 Delivery Year under the base case load forecast is estimated to be 42 MW. The average supply surplus during peak hours for the 2026-2027 Delivery Year is 44 MW and for the 2027-2028 Delivery Year the supply surplus is 44 MW.

Figure 4-3: MidAmerican's On-Peak Supply Gap - June 2025-May 2030 period - Base Case Load Forecast



5 PJM and MISO Resource Adequacy Outlook and Uncertainty

As a result of retail choice in Illinois, the resource adequacy challenge (i.e., the load and resource balance) can be summarized as a function of determining what level of resources to purchase and from which markets. However, for the Illinois market to function properly, the RTO markets and operations (e.g., MISO and PJM) must provide sufficient resources to satisfy the load requirements for all customers reliably. This Chapter reviews the likely load and resource outcomes over the planning horizon to determine if the current system is likely to provide the necessary resources such that customers will be served with reliable power.

In reviewing the load and resource outcomes, this Chapter analyzes several studies of resource adequacy that are publicly available from different planning and reliability entities. These entities include:

- North American Electric Reliability Corporation ("NERC"), the entity certified by the Federal Energy Regulatory Commission ("FERC") to establish and enforce reliability standards with the goal of ensuring the reliability of the bulk power system.
- PJM Interconnection, L.L.C. ("PJM"), which operates the transmission grid in Northern Illinois, serving ComEd.
- Midcontinent Independent System Operator, Inc. ("MISO"), which operates the transmission grid in most of central and southern Illinois, serving Ameren Illinois and MidAmerican.

The 2023 NERC Long-Term Reliability Assessment ("2023 NERC LTRA") provides a region-wide annual forecast of resource adequacy for both MISO and PJM for a period of ten years. As noted in previous procurement plans, the findings of this annual forecast are based on the resource assumptions available at the time the report is published. Most importantly, for MISO, the forecast is published five months before the release of the actual results of the MISO Planning Resource Auction ("PRA") for the most recent delivery year, which may result in a disconnect between the forecast and the actual results.[134] The most recent NERC forecast projected resource shortfalls for MISO starting in the 2028-2029 Delivery Year. For the current assessment of the 2024-2025 Delivery Year, there was agreement between the 2023 NERC LTRA and the MISO PRA. The results of the PRA showed sufficient capacity at the regional, sub-regional, and zonal levels, including MISO Zone 4 (which includes Illinois). One exception to capacity sufficiency was in MISO Zone 5, which is described in more detail in Section 5.2.2.5. The NERC forecast showed that PJM will maintain adequate resources to meet the collective needs of customers in the PJM region.

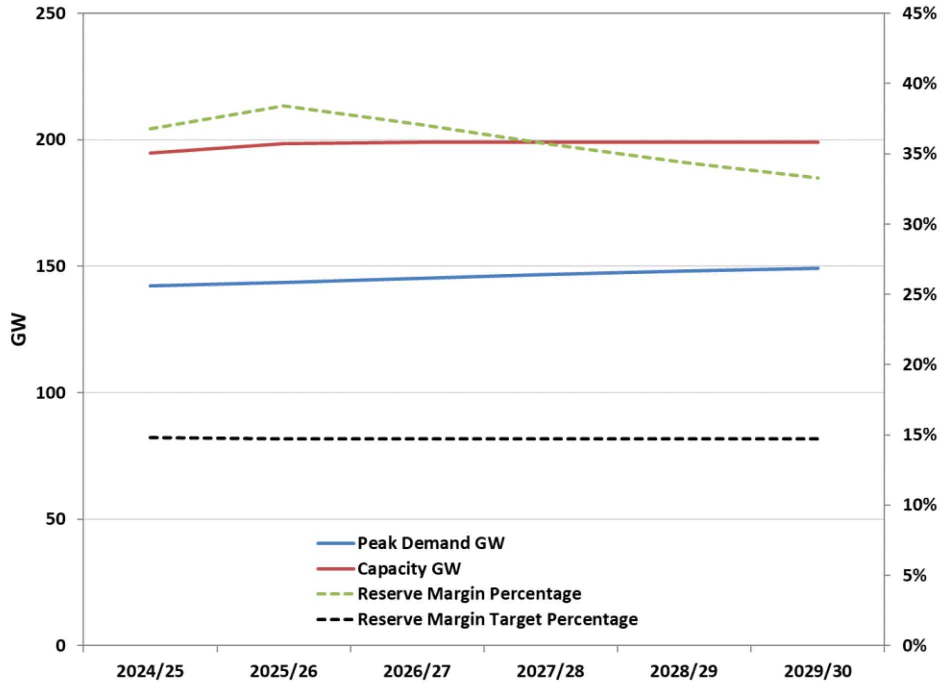
5.1 Resource Adequacy Projections

5.1.1 PJM RTO

As shown in Figure 5-1, based on the 2023 NERC LTRA, PJM is projected to have sufficient resources to meet load plus required reserve margins for Delivery Years 2024-2025 through 2029-2030, with projected reserve margins above the 14.8% target reserve margin for Delivery Year 2024-2025, and 14.7% target reserve margin for Delivery Years 2025-2026 to 2029-2030. For the 2024-2025 Delivery Year, the reserve margin is 22.0% above the target reserve margin and is 18.6% above the target reserve margin for the 2029-2030 Delivery Year.

[134] The reliability assessment by NERC was published in December 2023, five months before the results of the 2024-2025 MISO PRA were published. 2024-2025 is the most recent Delivery Year for the MISO PRA.

Figure 5-1: NERC Projection of Supply and Demand in PJM for Delivery Years 2024-2025 to 2029-2030



Source: 2023 NERC LTRA

5.1.2 MISO RTO

The 2023 NERC LTRA projects that MISO will have insufficient resources on a region-wide basis to meet load plus a target reserve margin starting with the 2028-2029 Delivery Year. The projections are shown in Figure 5-2. For the 2024-2025 Delivery Year, the reserve margin is approximately 9.5% above the target reserve margin, declining to 1.7% above the target reserve margin for the 2027-2028 Delivery Year, falling to 4% below the target reserve margin for the 2028-2029 Delivery Year, and further dropping to 7.7% below the target reserve margin for the 2029-2030 Delivery Year.

For the 2024-2025 Delivery Year, there was agreement between the 2023 NERC LTRA and the PRA, as the results of the PRA showed sufficient capacity at the regional, sub-regional, and zonal levels, including Zone 4 that includes Illinois. Zone 5 is not projected to have capacity sufficiency, as described in more detail in Section 5.2.2.5.

The results of the 2024 survey jointly conducted by MISO and the Organization of MISO States ("2024 MISO-OMS Survey") indicate a potential surplus of 1.1 GW to a deficit of 2.7 GW of capacity for the summer of the 2025-2026 Delivery Year, depending on critical yet uncertain drivers, such as the pace and quantity of new resource additions.[135] An assumption of 6.1 GW/year of potential new capacity results in a surplus of 1.1 GW of capacity in the 2025-2026 Delivery Year. On the other hand, a more conservative assumption of 2.3 GW/year of potential new capacity results in a deficit of 2.7 GW of capacity in the 2025-2026 Delivery Year.

While the IPA acknowledges the findings of the 2023 NERC LTRA's region-wide long-term assessment, the IPA also notes that the results of these findings are based on the resource assumptions available at the time the report is published.

The IPA will continue to review and analyze the various studies and assessments to estimate the accuracy of future resource adequacy projections.

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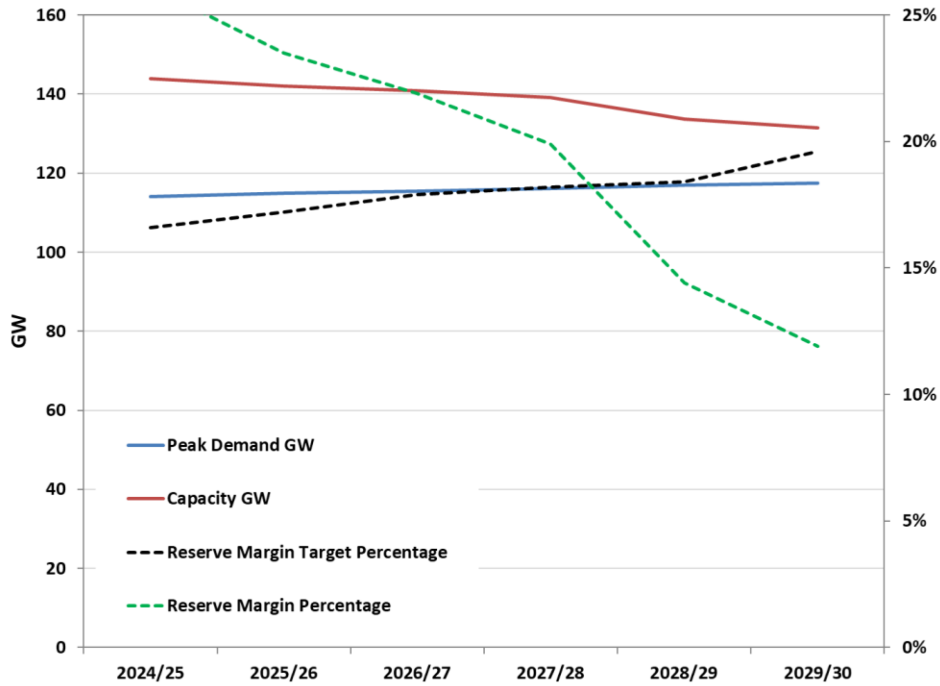
135 https://cdn.misoenergy.org/20240620%20OMS%20MISO%20Survey%20Results%20Workshop%20Presentation635585.pdf

Figure 5-2: NERC Projection of Supply and Demand in MISO for the Delivery Years 2024-2025 to 2029-2030



Source: 2023 NERC LTRA

5.2 RTO Administered Organized Capacity Auctions

Electric power systems should have sufficient capacity resources to meet peak load requirements plus a planning reserve margin to maintain resource adequacy and ensure reliable system operations. Regional transmission organizations like PJM and MISO operate centralized competitive capacity markets to help ensure resource adequacy and reliability. This section provides a brief overview and a regulatory update of these organized capacity markets.

5.2.1 PJM Reliability Pricing Model

In PJM, capacity is largely procured through the PJM-organized capacity market, the Reliability Pricing Model ("RPM"), which was approved by FERC in December 2006. In 2015, PJM implemented changes to the RPM construct, which established a Capacity Performance product.[136] The RPM is a forward capacity auction through which generators offer capacity to serve the obligations of load-serving entities ("LSEs"). The primary capacity auctions, Base Residual Auctions ("BRAs"), are held each May three years prior to the commitment period. In the RPM construct, the commitment period is referred to as a "Delivery Year." In this Plan, "Delivery Year" is also used in relation to all capacity and energy procurements.[137] In addition to the BRAs, up to three incremental auctions are held, at intervals of 20 months, 10 months, and 3 months prior to the Delivery Year. The 1st, 2nd, and 3rd Incremental Auctions are conducted to allow for replacement resource procurement, increases and decreases in resource commitments due to reliability requirement adjustments, and deferred

[136] On June 9, 2015, FERC accepted PJM's proposal to establish a new capacity product, a Capacity Performance Resource, on a phased-in basis, to ensure that PJM's capacity market provides adequate incentives for resource performance during emergency conditions (FERC Docket No. ER15-623 et al., 151 FERC ¶ 61,208). Resources that are committed as capacity performance resources will be paid incentives to ensure that they deliver the promised energy and reserves when called upon in emergencies. Capacity Performance has been fully implemented for the 2018-2019, 2019-2020, 2020-2021, 2021-2022, 2022-2023, 2023-2024, and 2024-2025 Delivery Years, with transitional capacity performance incremental auctions conducted for the 2016-2017 and 2017-2018 years to facilitate improved resource performance during those years by allowing a portion of capacity to be rebid as Capacity Performance Resources in a new procurement. Implementation of Capacity Performance has generally resulted in increased capacity clearing prices, in particular for the ComEd zone.

[137] As noted above, a Delivery Year is June 1 through May 31 of the following year. The use of "Delivery Year" in this Plan also applies to the MISO RTO where the term "Planning Year" is normally used.

short-term resource procurement.[138] A Conditional Incremental Auction may be conducted, if and when necessary, to secure commitments of additional capacity to address reliability criteria violations arising from the delay of a backbone transmission upgrade that was modeled in the BRA.

The Final Zonal Net Load Price, which is the price paid by LSEs for capacity procured as part of the RPM, is calculated just prior to the beginning of each Delivery Year. This price is determined based on the results of the BRA and subsequent incremental auctions for a given year. As the procurement of the majority of the capacity via the RPM is done during the BRA, there is little variation between the BRA clearing price (Preliminary Zonal Capacity Price) and the Final Zonal Net Load Price as shown in Figure 5-3. However, while Figure 5-3 shows little variation in the ComEd zone between the BRA clearing price and the Final Zonal Net Load Price for the Delivery Years through 2015-2016, Delivery Years 2016-2017 and 2017-2018 show a significant variation between the prices. This is because the Final Zonal Net Load Price for 2016-2017 and 2017-2018 includes the incremental costs of each year's transitional Capacity Performance Incremental Auction ("CPIA").[139]

Figure 5-3 shows higher BRA prices in the ComEd zone for Delivery Years 2018-2019 through 2021-2022 relative to 2017-2018, which are attributable to the transition to full implementation of the Capacity Performance product (i.e., Capacity Performance Resources bidding in the BRA) as well as transmission constraints in the ComEd LDA. There is also a notable drop in price in Delivery Years 2022-2023, 2023-2024, and 2024-2025.[140] However, the results for the 2025-2026 Delivery Year were released by PJM on July 30, 2024 and show a very dramatic increase in the capacity price.[141]

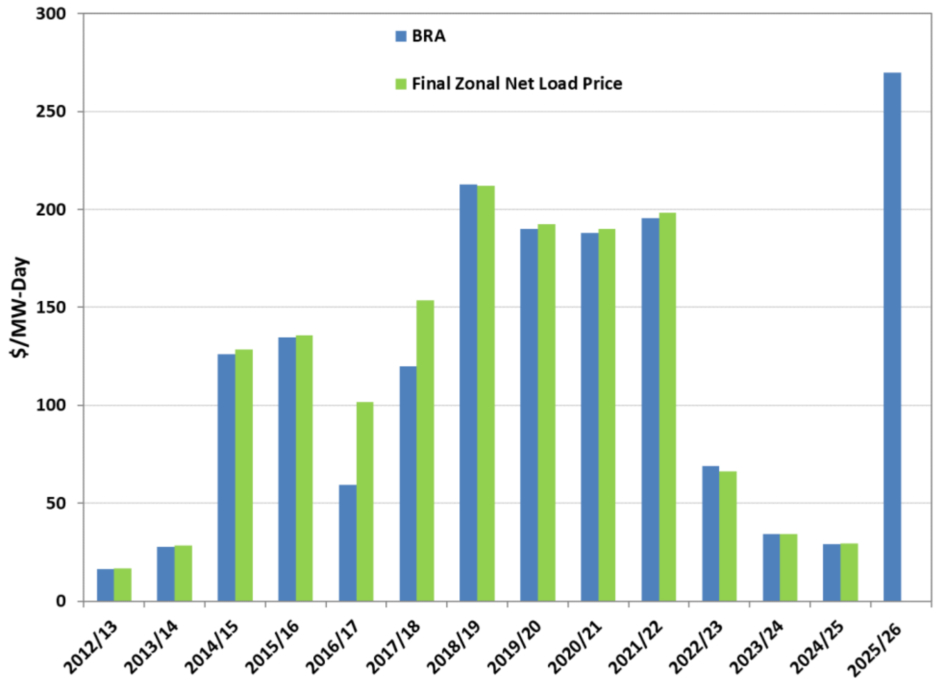
[138] Deferred short-term resource procurement only applies prior to the 2018-2019 Delivery Year.

[139] The BRA clearing price (Preliminary Zonal Capacity Price) for the ComEd zone for 2016-2017 was $59.37/MW-Day. 60% of resources procured in the 2016-2017 CPIA were Capacity Performance Resources. The preliminary incremental cost component for the 2016-2017 CPIA was $38.17/MW-Day and the final incremental cost component was $39.86/MW-Day. After factoring in the adjustments to account for the results of the 1st, 2nd, and 3rd incremental auctions, the Final Zonal Net Load Price was $101.62/MW-Day, a 71% increase from the BRA clearing price. 70% of resources procured in the 2017-2018 CPIA were Capacity Performance Resources. The BRA clearing price for the ComEd zone for 2017-2018 was $119.81/MW-Day. The preliminary incremental cost component for the 2017-2018 CPIA was $27.69/MW-Day and the final incremental cost component was $29.97. After factoring in the adjustments to account for the results of the 1st, 2nd, and 3rd incremental auctions, the Final Zonal Net Load Price for 2017-2018 was $153.61/MW-Day, a 28% increase from the BRA clearing price.

[140] In 2017-2018, 2018-2019, 2019-2020, 2020-2021, 2021-2022, 2022-2023, 2023-2024, and 2024-2025 the ComEd Zone was modeled as a separate Locational Deliverability Area ("LDA"), and in all years starting with 2018-2019, with the exception of 2023-2024 and 2024-2025, the results showed that the zone was a constrained LDA. Binding constraints therefore also contributed to the higher clearing price although 2022-2023, 2023-2024, and 2024-2025 cleared at a significantly lower price than the previous years. For 2022-2023 the lower price was due to a lower load forecast and reserve requirement, and overall lower prices from resources participating in the BRA. For 2023-2024 potential factors contributing to the lower clearing price include, but are not limited to, (i) the first application of the less restrictive minimum offer price rule, (a revised lower unit-specific market seller offer cap, (ii) less lead time to the delivery year (one year instead of three), and (iii) expected higher energy prices leading to lower offers in the capacity market. For 2024-2025 the lower price was due to overall lower prices of resources participating in the BRA.

[141] See: https://pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2025-2026/2025-2026-base-residual-auction-report.ashx.

Figure 5-3: PJM (ComEd Zone) Capacity Price for Delivery Years 2012-2013 to 2024-2025[142]



As explained in more detail in the IPA's 2020 Electricity Procurement Plan,[143] FERC issued a number of orders that would significantly change PJM's RPM in the future. As noted in the 2020 Electricity Procurement Plan, FERC issued an Order[144] on June 29, 2018 providing that an important component of PJM's RPM, the Minimum Offer Price Rule ("MOPR"), was unjust and unreasonable because it does not address the impact of state-subsidized existing resources on the capacity market.

FERC instituted a proceeding[145] under Section 206 of the Federal Power Act to find a replacement for the current MOPR.

On October 2, 2018, PJM filed a proposal that had two main features: (i) an expanded MOPR that would apply to all fuel and technology types as well as to existing and new resources, and (ii) a Resource Carve-Out ("RCO") that would allow resources subject to the MOPR to receive capacity market payments without bidding into the PJM capacity market.[146]

On December 19, 2019, FERC issued an Order[147] that expanded the MOPR to apply to all fuel and technology types (new and existing resources). The expanded MOPR also includes new and existing demand response, energy efficiency, storage, and all resources owned by vertically-integrated utilities. Essentially, with certain exceptions, all existing and new resources receiving a state subsidy would not be allowed to offer capacity bids below the applicable MOPR floor. FERC directed PJM to develop applicable MOPR floors for new and existing resources using 100% of the cost of new entry and net avoided cost, respectively. FERC also rejected the RCO

[142] 2024-2025 is the latest Delivery Year for which the Final Zonal Net Load Price has been calculated. It will be calculated for future Delivery Years as the start of the year approaches.

[143] See pages 46-48 of the IPA's 2020 Electricity Procurement Plan at https://ipa.illinois.gov/content/dam/soi/en/web/ipa/documents/2020-final-electricity-procurement-plan/ipa-final-2020-electricity-procurement-plan.pdf.

[144] Order Rejecting Proposed Tariff Revisions, Granting in Part and Denying in Part Complaint, and Instituting Proceeding Under Section 206 of the Federal Power Act, 163 FERC ¶ 61,236, FERC Docket No. EL16-49-000 et al, June 29, 2018.

[145] FERC Docket No. EL18-178-000.

[146] Initial Submission of PJM Interconnection, L.L.C, FERC Docket No. EL18-178-000 (Consolidated), October 2, 2018.

[147] Order Establishing Just and Reasonable Rate, FERC Docket No. EL18-178-000 (Consolidated), December 19, 2019.

option. FERC directed PJM to submit a compliance filing within 90 days, including a proposed schedule for future capacity auctions.

On March 18, 2020, PJM submitted its compliance filing in response to FERC's December 19, 2019 Order.[148] In its filing, PJM submitted revisions to their tariff that would modify the application of the MOPR to address state subsidies and their impact in the PJM capacity market. The PJM filing also provided a timetable for conducting the BRA for the 2022-2023 Delivery Year. Specifically, PJM proposed to complete all pre-auction activities and open the BRA for the 2022-2023 Delivery Year within six and a half months after the date of FERC's acceptance of PJM's compliance filing. In order to accommodate a request made by the Organization of PJM States to delay the BRA to May 2021,[149] PJM proposed that, in the event that legislation directly applicable to new elections of the Fixed Resource Requirement Alternative[150] is enacted before June 1, 2020, and upon request of a state public utility commission acting in its official capacity, PJM would have the limited ability to extend the schedule for the BRA to no later than March 31, 2021.

On April 16, 2020, FERC issued an Order[151] addressing requests for rehearing of its December 19, 2019 Order. In the April 16, 2020 Order, FERC largely upheld their December 19, 2019 Order. FERC also directed PJM to make another compliance filing within 45 days of the date of the Order (i.e., by June 1, 2020). On June 1, 2020, PJM submitted the second compliance filing[152] addressing the issues raised in FERC's Order which included, but were not limited to (i) modifying the March 18, 2020 filing to include separate provisions for the pre-existing MOPR and the new MOPR for capacity resources with a state subsidy; (ii) clarifying that state default service procurements are state subsidies, and proposing language that will allow for the continuation of normal commercial activity associated with state default service auctions while safeguarding against any revenues that would distort the competitiveness of the RPM auctions; (iii) updating the March 18, 2020 filing to clarify that subsidized capacity resources procured in a bilateral transaction cannot be used to replace a non-subsidized capacity resource's capacity commitment; and (iv) revising the proposed tariff language to be consistent with FERC's clarification in the April 16, 2020 Order that zonal net revenues are to be used for calculating default offer price floors for new capacity resources and that resource-specific net revenues should be used for calculating default net avoidable cost rate values for existing resources.

On October 15, 2020, FERC issued an Order[153] largely accepting PJM's June 1, 2020 compliance filing, denying the compliance filing in part, and directed PJM to submit another compliance filing within 30 days of the Order. In that Order, FERC indicated that the date for the upcoming 2022-2023 Base Residual Auction could not be set until an Order on the pending Energy and Ancillary Services ("E&AS") compliance filing was resolved.[154]

On November 12, 2020, FERC approved PJM's E&AS compliance filing,[155] clearing the path for PJM to establish the dates for the upcoming RPM auctions, as well as the deadlines for the associated pre-auction activities. One day later, on November 13, 2020, PJM submitted its compliance filing required under the October 15, 2020 FERC Order from the MOPR proceeding. In that compliance filing, PJM noted that, consistent with FERC's Order, PJM had not set the date for the next Base Residual Auction as it was still awaiting FERC's Order on PJM's E&AS compliance filing. PJM further noted, now that FERC had accepted PJM's E&AS compliance filing, PJM would proceed in establishing the dates for the upcoming RPM auctions, as well as the deadlines for the associated pre-auction activities. PJM set May 19, 2021 as the date for the 2022-2023 Base Residual Auction.

On April 6, 2021, the PJM Board issued a letter to PJM stakeholders asking them to pursue several topics related to the capacity market. One of the topics included "Implementing changes to the Minimum Offer Price Rule (MOPR) to ensure the capacity market accommodates state policy choices related to resource mix, as well as

[148] Compliance Filing Concerning the Minimum Offer Price Rule, Request for Waiver of RPM Auction Deadlines, and Request for An Extended Comment Period of At Least 35 Days, FERC Docket No. EL18-178-000, March 18, 2020.

[149] See letter from the Organization of PJM States, Inc., to the PJM Board of Managers, at https://www.pjm.com/-/media/about-pjm/who-we-are/publicdisclosures/20200219-opsi-letter-re-scheduling-next-base-case-residual-auction.ashx?la=en.

[150] The Fixed Resource Requirement Alternative allows an LSE to opt out of participating in the PJM capacity auction and satisfy its obligation to commit unforced capacity by submitting a capacity plan.

[151] Order on Rehearing and Clarification, FERC Docket No. EL18-178-002, April 16, 2020.

[152] Second Compliance Filing Concerning Application of The Minimum Offer Price Rule, FERC Docket No. ER18-1314-006, June 1, 2020.

[153] Order on Compliance, Granting Waiver Request, Addressing Arguments raised on Rehearing, and Setting aside Prior Order, in Part, FERC Docket No. EL18-1314-006 (Consolidated), October 15, 2020.

[154] For E&AS filing, see PJM Compliance Filing, FERC Docket No. EL19-58-003, August 5, 2020.

[155] FERC approved the E&AS compliance filing in an Order issued on November 12, 2020. See Order on Compliance, FERC Docket EL19-58-003.

long established self-supply business models, while adequately mitigating buyer-side market power."[156] In the letter, the PJM Board further noted that the issue of critical importance, which the PJM stakeholders should address first, is the MOPR and its future application in the capacity market. The Board also noted that, although FERC had not formally spoken on the issue, a recent FERC technical conference focused heavily on the MOPR, and the FERC Chair provided clear publicly stated guidance that he wanted this issue addressed as soon as practicable. Given the importance of the issue the PJM Board requested that the discussion to modify the MOPR should be advanced via the Critical Issue Fast Path (CIFP) accelerated stakeholder process mechanism to try and achieve stakeholder consensus that would inform a PJM Board decision on a potential filing with FERC.

PJM instituted a CIFP-MOPR stakeholder process which discussed various proposals for modifying the MOPR.[157] On July 27, 2021 the PJM Board approved the PJM proposal which had received majority stakeholder support and instructed PJM to prepare the PJM proposal for filing with FERC.[158] PJM filed their proposal with FERC on July 30, 2021.[159] PJM's proposal would replace the existing MOPR provisions in the PJM Tariff. The PJM proposal, which was to be effective starting with the 2023-2024 delivery year, was meant to protect the PJM capacity market from buyer-side market power and state actions that directly interfere with capacity auction clearing prices, while accommodating state public policies and self-supply models. Under PJM's proposal, the MOPR would be applied to generation capacity resources that exercise Buyer-Side Market Power[160] and generation capacity resources that receive Conditioned State Support.[161] PJM would require capacity market sellers to certify 1) whether, at the time of certification, their generation capacity resource is receiving or expected to receive Conditioned State Support, and 2) that the capacity market seller acknowledges and understands that the exercise of Buyer-Side Market Power is not permitted in PJM's RPM auctions and the seller does not intend to submit a sell offer for their generation capacity resource as an exercise of Buyer-Side Market Power.

On September 29, 2021, PJM's proposal became effective by operation of law due to the absence of FERC action because the commissioners were divided two against two as to the lawfulness of the proposal.[162]

The PJM BRAs have been delayed a number of times for various reasons. The most recent delay impacts the auction schedules for the 2025-2026 through 2028-2029 Delivery Years. The auction schedule revisions were meant to allow for the auctions to be conducted after FERC has taken action following PJM's proposed RPM reform and tariff changes, which were filed on October 13, 2023.[163] FERC approved the changes on January 30, 2024.[164] The schedule for the 2025-2026 BRA, which was initially delayed to June 2024, was further delayed to July 2024 to allow PJM more time to provide education on the implementation of the recently approved marginal effective load carrying capability accreditation methodology. The schedule for the 2026-2027 BRA has been delayed to December 2024, the schedule for the 2027-2028 BRA has been delayed to June 2025, and the schedule for the 2028-2029 BRA has been delayed to December 2025. The schedule for the 2029-2030 BRA will be back on the regular schedule in May 2026. FERC approved the new schedules in its Order issued on June 9, 2023.[165]

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[156] https://www.pjm.com/-/media/about-pjm/who-we-are/public-disclosures/20210406-board-letter-regarding-capacity-market-minimum-offer-price-rule-and-initiation-of-the-critical-issue-fast-path-process.ashx

[157] https://www.pjm.com/committees-and-groups/cifp-mopr.

[158] https://www.pjm.com/-/media/about-pjm/who-we-are/public-disclosures/20210708-board-letter-communicating-critical-issue-fast-path-minimum-offer-price-rule-decision.ashx.

[159] Revisions to Application of Minimum Offer Price Rule, FERC Docket No. ER21-2582-000, July 30, 2021.

[160] Buyer-Side Market Power is the ability of a market participant with a load interest to suppress market-clearing prices for the overall benefit of the participant's portfolio.

[161] Conditioned State Support is defined as out-of-market payments provided by states to generation capacity resources in exchange for the sale of a FERC-jurisdictional product conditioned on clearing in any PJM capacity market. Conditioned State Support refers to any directives the state may provide as to the price level at which a generation capacity resource must be offered in the PJM RPM auction or directives that the generation capacity resource is required to clear in any PJM RPM auction.

[162] Notice of Filing Taking Effect by Operation of Law, FERC Docket No. ER21-2852-000, September 29, 2021.

[163] Capacity Market Reforms to Accommodate the Energy Transition While Maintaining Resource Adequacy, FERC Docket No. ER-24-99-000, October 13, 2023.

[164] Order Accepting Tariff Conditions Subject to Condition, FERC Docket No. ER24-99-000/001, January 30, 2024.

[165] Order Accepting Tariff Revisions, Subject to Condition, and Granting Waiver Request, FERC Docket No. ER23-1609-000, June 9, 2023.

5.2.1.1 Capacity Hedging for ComEd

As shown in Figure 5-3, PJM capacity prices for the upcoming 2025-2026 Delivery Year increased from $28.92 to $269.92 per MW-day. While capacity prices were expected to increase,[166] this increase was significantly higher than those expectations and may indicate a new era of capacity pricing and volatility for PJM and for the purpose of consideration in this plan, the ComEd zone.

According to PJM, auction prices were significantly higher across the RTO due to decreased electricity supply offers in the auction caused primarily by a large number of generator retirements, increased projected peak load, and implementation of FERC-approved market reforms including improved reliability risk modeling for extreme weather and accreditation that more accurately values each resource's contribution to reliability.[167] PJM's President and CEO Manu Asthana has said, "significantly higher prices in this auction confirm our concerns that the supply/demand balance is tightening across the RTO. The market is sending a price signal that should incent investment in resources."[168]

For the 2025-2026 and 2026-2027 delivery years, the impact of higher capacity prices will be partially blunted by a corresponding decline in the price of Carbon Mitigation Credits ("CMCs"), potentially even turning the price of those credits negative and thus resulting in a bill credit for retail customers. (See Section 6.9 for further discussion of this mechanism). However, this offsetting effect of CMC contracts only covers about 60% of load. Residential and small commercial customers also pay a disproportionate share of capacity costs as their load profiles are peakier than other customer classes.

In light of this new price volatility, the Agency sought stakeholder feedback through its draft 2025 Plan on the advantages and disadvantages of the Agency beginning to procure capacity for ComEd eligible retail customers as a way to mitigate risks created by this price volatility and to increase stability of rates. The Agency included the following questions in the draft Plan:

- Should the Agency consider procuring capacity for ComEd eligible retail customers?
- If the Agency begins procuring capacity for ComEd eligible retail customers, how should the Agency structure the capacity product? In particular, are there any recommendations on what portion (in percentage terms) of ComEd eligible retail customer capacity obligation should be hedged, and what portion (in percentage terms) should be procured through the BRA?
- Given the three-year forward design of the PJM capacity market, are there hedging opportunities for PJM capacity that differ from the hedging opportunities that exist in the MISO market which is for prompt year capacity?
- Do stakeholders expect to see similar or different results in the 2026-2027 BRA results scheduled for release in December 2024? Do stakeholders expect that the price signals sent by the 2025-2026 results may spur new market entries in time for that auction?

The only feedback received was from ComEd, who noted that eligible retail customers "pay a disproportionate share of capacity costs because their load profiles are more susceptible to variable peak demands than other customer classes."[169] However, ComEd opined that given the timing of PJM capacity auctions and the timing/constraints for the development of any new resources in the ComEd zone, "there is likely insufficient time for Commission consideration and action on potential alternatives that would alleviate ComEd's obligations related to PJM capacity purchases through May 2028."[170]

ComEd also noted that, "existing alternatives to the current PJM BRA construct are limited, and thus the vast majority of Load Serving Entities ("LSEs") in PJM procure the capacity resources they need through PJM's competitive capacity market."[171] While the Agency shares ComEd's concerns about the impact of increasing

[166] See for example, "Almost 20% of Americans face prospect of higher electric bills," Crains Chicago Business, July 29, 2024, https://www.chicagobusiness.com/utilities/electric-bills-set-rise-demand-spikes-pjm-grid.

[167] See https://insidelines.pjm.com/pjm-capacity-auction-procures-sufficient-resources-to-meet-rto-reliability-requirement/.

[168] Id.

[169] See ComEd comments at: https://ipa.illinois.gov/content/dam/soi/en/web/ipa/documents/20240917-comed-comments.pdf.

[170] Id.

[171] Id.

capacity prices on eligible retail customers, ComEd did not provide a specific recommendation on whether or how the Agency could procure capacity for ComEd eligible retail customers to help manage the increased volatility of PJM capacity prices. The Agency does not see any clear path forward for a simple capacity procurement that would provide value to ComEd eligible retail customers. Therefore, at this time the IPA does not propose to conduct any hedging of capacity for ComEd eligible retail customers. Addressing increasing capacity challenges in the ComEd zone of the PJM market will require broader solutions in regulatory and legislative venues.

5.2.2 MISO Planning Resource Auction

The MISO Resource Adequacy Construct, specified in Module E-1 of its Tariff,[172] contains the Resource Adequacy Requirements ("RAR") that require LSEs in the MISO region to procure sufficient Planning Resources to meet their anticipated peak demand, plus a planning reserve margin ("PRM")[173] for the Delivery Year. An LSE's total resource adequacy obligation is referred to as the Planning Reserve Margin Requirement ("PRMR"). On June 11, 2012, FERC conditionally approved MISO's proposal to enhance its RAR by establishing an annual construct based upon meeting reliability requirements on a locational basis, including the use of an annual Planning Resource Auction or PRA. MISO implemented the Module E-1 RAR, which became fully effective on June 1, 2013.

On December 15, 2017, MISO filed the currently effective provisions of its Tariff governing resource adequacy in MISO with FERC, informing FERC that their filing did not change any of the current Tariff provisions regarding MISO's resource adequacy requirements, and requesting that FERC reaffirm that these provisions are just and reasonable.[174] On February 28, 2018, FERC issued an Order accepting MISO's filing.[175] However, MISO's Independent Market Monitor ("IMM") asserted that "it does not believe that the Auction outcomes have been just and reasonable because the prices produced through the Auction have departed from any reasonable measure of an efficient capacity price level."[176] The MISO IMM further stated that "it expects prices to continue to clear at near-zero prices due to attributes of MISO's construct including the vertical demand curve coupled with new restrictions on capacity imports by PJM Interconnection, LLC (PJM) and increased sub-regional transfer capability between MISO South and MISO Midwest."[177]

On March 26, 2018, MISO filed changes to the MISO Tariff to enhance the locational aspect of their Resource Adequacy Construct with FERC by (i) creating External Resource Zones ("ERZs"), (ii) allocating excess auction revenues through Historic Unit Considerations ("HUCs"), and (iii) aligning parameters used to calculate auction inputs such as Capacity Import Limits ("CIL"), Capacity Export Limits ("CEL"), and Local Clearing Requirements ("LCR") with the use of these limits in the PRA.[178] FERC's Staff issued a Deficiency Letter[179] to MISO on May 15, 2018, to which MISO responded on June 5, 2018.[180] FERC issued an Order on August 2, 2018 rejecting MISO's proposed tariff revisions but providing some guidance for a revised proposal.[181] On August 31, 2018 MISO submitted a revised proposal.[182] On October 31, 2018, FERC issued an Order accepting MISO's filing.[183]

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172 Under the MISO Tariff Module E-2 outlines, the RAR compliance obligations for a new LSE during a transitional period until the new LSE's assets can be included in the full annual RAR process in accordance with Module E-1.

173 The PRM (or target reserve margin) is determined by MISO, based on a Loss of Load Expectation ("LOLE") of one day in ten years, or state-specific standards. If a state regulatory body establishes a minimum PRM for the LSEs under its jurisdiction, then that state-set PRM would be adopted by MISO for jurisdictional LSEs in that state.

174 Refiling of MISO's Resource Adequacy Construct, FERC Docket No. ER18-462-000, December 15, 2017.

175 Order Accepting Tariff Filing, 162 FERC ¶ 61,176, FERC Docket No. ER18-462-000, February 28, 2018.

176 Id. at 6.

177 Id.

178 MISO filing to "Enhance Locational Aspect of Resource Adequacy Construct", FERC Docket No. ER18-1173-000, March 26, 2018.

179 See https://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=14920258.

180 See https://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=14938877.

181 Order on Tariff Filing, 164 FERC ¶ 61,081, FERC Docket No. ER18-1173-000 et al., August 2, 2018.

182 Refiling of Resource Adequacy Construct Locational Enhancements, FERC Docket No. ER18-2363-000, August 31, 2018.

183 Order Accepting Tariff Filing, 165 FERC ¶ 61,067, FERC Docket No. ER18-2363-000, October 31, 2018.

In the spring of 2013, MISO administered its first PRA which covered the 2013-2014 Delivery Year. Since then, in the spring of each year, MISO has conducted its annual PRA; the spring 2024 MISO PRA was the twelfth auction administered by MISO.

As described in more detail in Section 5.2.2.1, beginning with the 2023-2024 Delivery Year, MISO has implemented a seasonal resource adequacy construct.

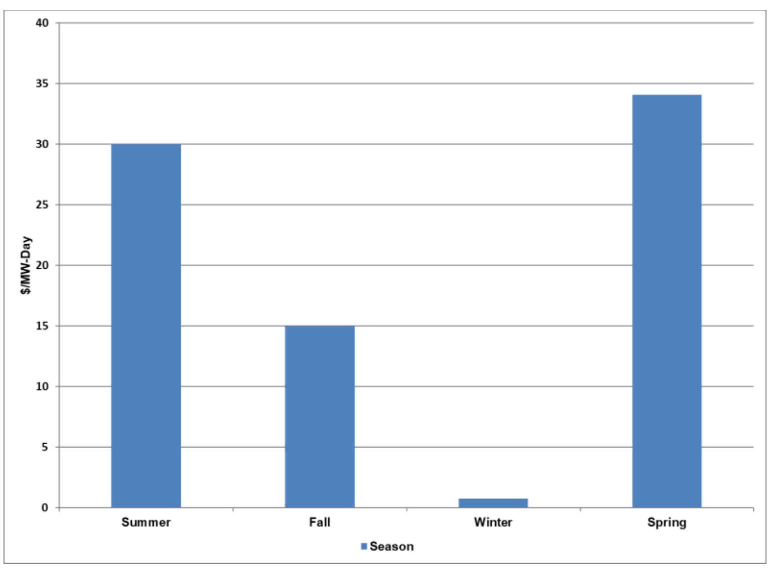
5.2.2.1 Seasonal Resource Adequacy Construct

Effective with the 2023-2024 Delivery Year, MISO has implemented a seasonal resource adequacy construct. As explained in the IPA's 2023 Electricity Procurement Plan, MISO has transitioned from the previous Summer-based, annual construct to four distinct Seasons: June to August for Summer, September to November for Fall, December to February for Winter, and March to May for Spring.[184] Under the new construct, MISO establishes PRMRs for all market participants representing load serving entities on a seasonal basis. MISO also develops seasonal local reliability requirements, seasonal LCRs, seasonal capacity import limits, and seasonal capacity export limits. MISO then conducts the PRA and establishes an Auction Clearing Price for each Local Resource Zone ("LRZ") for each season. The PRA is conducted once each year, in the spring before the applicable Delivery Year, but clears the requirements for each season.

Under the Seasonal Resource Adequacy Construct, MISO also determines seasonal accredited capacities for certain classes of resources. The affected resources are Demand Response Resources and Capacity Resources that are Generation Resources (collectively "Schedule 53 Resources"). These Schedule 53 Resources are subject to the availability-based accreditation methodology established in a new Schedule 53 of the MISO Tariff. Resources that are not subject to Schedule 53 (Dispatchable Intermittent Resources, Intermittent Generation, Electric Storage Resources, External Resources or Use Limited Resources) continue to have their accreditation determined generally as before, with appropriate adjustments made to convert their accreditation to a seasonal basis.[185]

The results of the second seasonal PRA were released on April 26, 2024.[186] Figure 5-4 shows the seasonal PRA results for Zone 4 (which includes Illinois) for Delivery Year 2024-2025. An explanation of the results is provided in Section 5.2.2.5.

Figure 5-4: 2024-2025 Delivery Year Seasonal PRA Results for MISO Zone 4



[184] See IPA's 2023 Electricity Procurement Plan, Section 5.2.2.1.

[185] This accreditation process, which for thermal resources is based on Unforced Capacity ("UCAP"), is determined using resource performance between September 1 and August 31 of the three years prior to the Planning Year. This data is used to determine Equivalent Forced Outage Rate Demand ("XEFORd"), excluding events outside of management control, which is then used as a component in the calculation of UCAP. The UCAP is calculated by taking Installed Capacity ('ICAP") and multiplying it by (1- XEFORd).

[186] The PRA results can be found at: https://cdn.misoenergy.org/2024%20PRA%20Results%20Posting%2020240425632665.pdf

The IPA notes that in line with the MISO Tariff and the move to a Seasonal Resource Adequacy Construct, changes have been made to the IPA's bilateral procurement approach. The IPA has stopped procuring annual ZRCs and is now conducting bilateral procurements for each of the four seasons and procuring seasonal ZRCs.[187] The results of the seasonal procurements conducted by the IPA to date can be found on the IPA's website.[188]

For a given Delivery Year, MISO procures all seasonal capacity products in one auction (rather than separately timed auctions for each season). The IPA is also conducting procurements of seasonal ZRCs for all four seasons simultaneously; however, consistent with the IPA's general approach of laddered hedging, the procurement of seasonal ZRCs for a given Delivery Year is conducted over multiple procurement events in the two years prior to the given Delivery Year. The target quantities of seasonal ZRCs used for each procurement event is based on updated capacity forecasts that are provided by Ameren Illinois.

5.2.1.2 MISO's Filing to Reform Resource Accreditation Requirements

In its filing to reform resource accreditation requirements,[189] MISO notes that it is at an inflection point in its portfolio evolution. Sizable segments of dispatchable thermal generation are aging into retirement and being replaced with increasing amounts of highly weather-dependent intermittent wind and solar resources. These retirements, combined with the significant penetration of intermittent resources and increased frequency of extreme weather events, are shifting the nature of system risk and creating challenges to maintaining reliable system operations. These events are highlighting the fact that MISO's existing resource accreditation methods are no longer sufficiently robust to capture those risks and send the proper signals to state regulators and LSEs participating in integrated resource planning processes for the investment and retirement of resources needed to maintain reliability into the future.

In response to these challenges and the continued need for diversity in the resource mix, MISO proposes to transition to a direct loss of load-based methodology (DLOL-based methodology). The proposed method measures a resource's availability when reliability risk is the greatest. The proposal builds upon the current seasonal accreditation methodology. The DLOL-based methodology first measures a resource's expected marginal contribution to reliability using the resource's performance during a loss of load expectation ("LOLE") analysis. The second step in the DLOL-based methodology then uses historical resource-level performance (deterministic approach) in the hours that are currently employed under MISO's Tariff to accredit individual resources within their respective resource class. The DLOL-based methodology is meant to address a range of reliability risks in the planning and operations horizons by incorporating a forward-looking probabilistic analysis and measuring a resource's performance during recent periods of high system risk. Under the proposal, MISO defines the periods of highest system risk identified in the probabilistic analysis as "Critical Hours." Critical Hours include all loss of load hours and may also include low margin hours comprised of those hours where available generation in excess of load is less than or equal to 3% of load in that hour (*i.e.*, low margin).

MISO is proposing a change in how all capacity resources, except external resources (referred to as "Schedule 53A Resources"), receive capacity credit at the resource class-level, as well as how the resource class-level UCAP megawatts are allocated amongst the individual resources. In addition, MISO is proposing to use the same methodology to calculate the PRMR that it uses to accredit resource classes. The proposal thus preserves the deterministic element of resource accreditation established in Schedule 53 by accrediting all Schedule 53A resources based upon their actual performance during resource adequacy hours. The DLOL-based accreditation proposal also enhances the Schedule 53 methodology by adding a probabilistic element to perform resource class-level UCAP calculations to align the class-level accreditation of all Schedule 53A resources with the determination of PRMR.

The DLOL-based methodology will be fully implemented in the 2028-29 PRA, after a three-year transition period. As of the date of the filing of this Plan on September 30, FERC has yet to issue an order on MISO's filing.

[187] As discussed in Section 5.2.2.7, in this Plan the Agency is now proposing to also procure a financial swap contract product for capacity that will mirror volumes of ZRCs but not require their actual delivery to Ameren Illinois.

[188] See procurement results on https://ipa.illinois.gov/energy-procurement/current-approved-plan.html and https://ipa.illinois.gov/energy-procurement/prior-approved-plans.html.

[189] Filing to Reform MISO's Resource Accreditation Requirements, FERC Docket No. ER24-1638-000, March 28, 2024.

5.2.1.3 MISO's Filing to Implement a Reliability Based Demand Curve

In its filing to implement a reliability-based demand curve,[190] MISO notes that its historical application of a vertical demand curve in the PRA has contributed to low auction clearing prices as a result of setting the Auction Clearing Price close to zero when the market has even a small surplus of capacity and inversely setting an artificially high Auction Clearing Price at or near the Cost of New Entry if there is any shortfall of capacity. Vertical curves therefore tend to produce excess price volatility, more frequent pricing at the auction price cap, and more frequent capacity shortfalls. MISO further notes that the prolonged prevalence of low prices throughout much of the PRA's history disregarded the significance of incremental capacity, failed to incentivize new investments, and has played an adverse role in the premature retirement of both merchant and utility resources.

In order to fix the problems caused by the vertical demand curve, MISO is proposing to implement a downward sloping Reliability Based Demand Curve ("RBDC"), commonly known as a sloped demand curve. MISO notes that the RBDC would mitigate price volatility, modestly increase the total volume of capacity maintained in the market and reduce the frequency and severity of shortfalls. MISO proposes to implement the downward sloping, RBDC in the PRA beginning with the 2025 – 2026 Delivery Year.

On June 27, 2024, FERC issued an Order accepting MISO's filing.[191] In their Order FERC noted: "We find that MISO's downward-sloping demand curve will reduce volatility in Auction Clearing Prices, increase the stability of the capacity revenue stream over time, and render capacity investments less risky, thereby encouraging greater investment and at a lower financing cost. Additionally, we find that using the proposed sloped demand curve will result in capacity price signals that reflect the marginal reliability impact of incremental capacity additions, provide better incentives for efficient resource entry and exit, and as a result, improve resource adequacy and economic efficiency across the MISO footprint."[192] FERC accepted MISO's proposed Tariff revisions, effective June 3, 2024 (the beginning of the 2025-2026 Delivery Year), as requested by MISO.

5.2.1.4 Overview of Results of the MISO PRA

Figure 5-5 below shows the results of the MISO PRA since its inception. The results for the 2023-2024 and 2024-2025 Delivery Year are a weighted average of the seasonal results.[193]

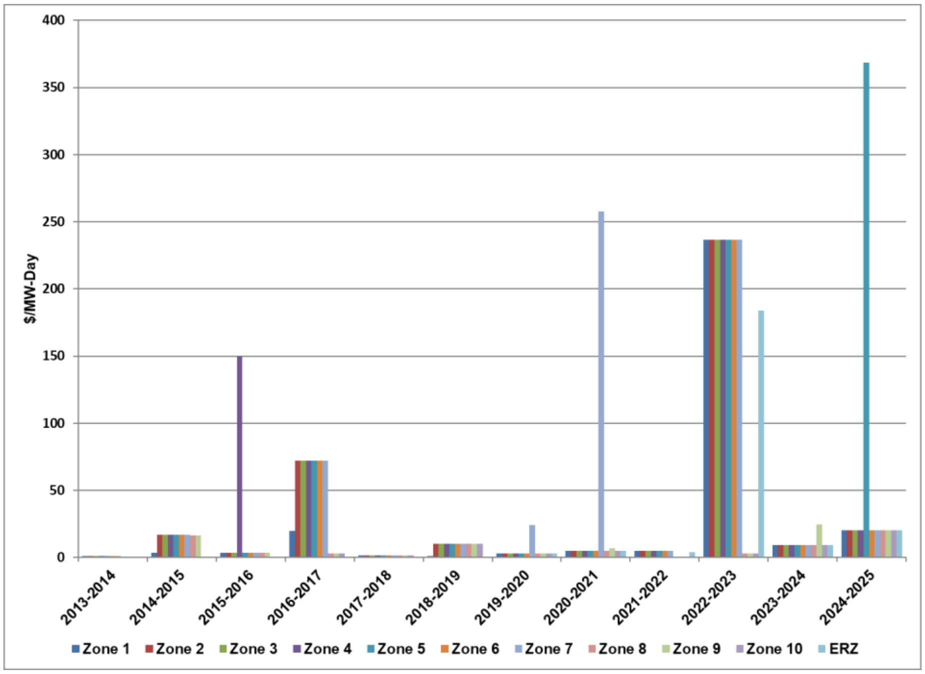
[190] Reliability Based Demand Curve, FERC Docket No. ER23-2977-000, September 29, 2023.

[191] Order Accepting Tariff Revisions, FERC Docket No. ER23-2977-000, June 27, 2024.

[192] Id. at page 36.

[193] The weighting of the results is based on the hours in each season.

Figure 5-5: MISO PRA Results for Delivery Years 2013-2014 to 2024-2025



As shown in Figure 5-5, and explained in detail in previous procurement plans, capacity prices in the MISO PRA have been volatile, ranging from a low of $1.00/MW-Day to a high of $257.53/MW-Day (for Zone 4 the range has been $1.05/MW-Day to $236.66/MW-Day). For the 2020-2021 PRA, most of the MISO zones cleared between $4.75/MW-Day and $6.88/MW-Day. Zone 7 (Michigan) cleared at $257.53/MW-Day, the Cost of New Entry ("CONE"). Zone 7 cleared at the CONE due to insufficient capacity to meet the LCR. The IPA notes that for the 2015-2016 PRA, in order to meet the LCR in Zone 4, a higher priced bid was selected, resulting in the zone clearing at $150/MW-Day, a price which was 9 times greater than the price for the previous Delivery Year. A detailed explanation of the results of the 2015-2016 PRA, including an analysis of the Zone 4 price, is provided in the IPA's 2016 Electricity Procurement Plan.[194] For the 2021-2022 PRA, Zones 1 through 7 cleared at $5/MW-Day, and Zones 8-10 cleared at $0.01/MW-Day. For the 2022-2023 PRA, Zones 1-7 cleared at $236.66/MW-Day, and Zones 8-10 cleared at $2.88/MW-Day. A detailed explanation of the results for the 2022-2023 are presented in the 2023 Electricity Procurement Plan.[195] For the 2023-2024 PRA, with the exception of the Fall and Winter prices for Zone 9 (Louisiana and parts of Texas), all zones cleared at the same seasonal prices: $10.00/MW-Day (Summer), $15.00/MW-Day (Fall), $2.00/MW-Day (Winter), and $10.00/MW-Day (Spring). The Fall and Winter prices for Zone 9 were $59.21/MW-Day and $18.88/MW-Day respectively. In the Fall and Winter, Zone 9 required higher priced supply within the zone to meet its LCRs. The results of the 2024-2025 PRA are explained in the Section 5.2.2.5 below.

5.2.1.5 Results of the 2024-2025 PRA

For the 2024-2025 Delivery Year, with the exception of the Fall and Winter prices for Zone 5 (Missouri), all zones cleared at the same seasonal prices: $30.00/MW-Day (Summer), $15.00/MW-Day (Fall), $0.75/MW-Day (Winter), and $34.10/MW-Day (Spring). The Fall and Winter prices for Zone 5 were $719.81/MW-Day, which is the seasonal CONE. In the Fall and Winter, Zone 5 cleared at the seasonal CONE due to inadequate capacity to meet its LCRs, driven by resource retirements and seasonal outages.

Figure 5-4 presents the seasonal PRA results for Zone 4. The weighted average seasonal results for all the zones are presented in Figure 5-5.

[194] See IPA's Final 2016 Electricity Procurement Plan, Section 5.2, pages 58-62.

[195] See IPA's Final 2023 Electricity Procurement Plan, Section 5.2.2.2.3, pages 60-62.

5.2.1.6 Request for Stakeholder Feedback on Capacity Hedging for Ameren Illinois Eligible Retail Customers and Proposed Approach

On June 10, 2024, the Agency requested feedback from stakeholders related to the capacity procurements the Agency conducts on behalf of the eligible retail customers of Ameren Illinois.[196] Specifically, the Agency sought responses on the following:

- How the implementation of a sloped demand curve would (i) impact the IPA's consideration of how to hedge capacity for Ameren Illinois eligible retail customers, and (ii) affect suppliers in their approach to the MISO capacity market—specifically to participation in the IPA's capacity procurement events. The Agency was also interested in recommendations on what portion (in % terms) of Ameren Illinois eligible retail customer capacity obligation should be hedged (and how far in advance), and what portion (in % terms) should be procured through the PRA.
- What considerations the Agency should utilize when developing benchmarks for capacity given the ongoing evolution of the MISO capacity market and the lack of transparent price data as can be found for block energy products.
- Whether the procurement of ZRCs from renewable resources or demand response should be evaluated differently than ZRCs supported by conventional generation.
- Whether (i) the current design of the procurement process for capacity conducted by the Agency contains unintended barriers to participation, and if so, what changes (within the procurement structure mandated by the Illinois Power Agency Act and the Public Utilities Act) could be implemented; (ii) the Agency should consider a change in the timing and frequency of capacity procurements from the current model which ties them to the Spring and Fall procurements for block energy; and (iii) the Agency should consider including the ability to bid on an annual combination product (e.g., a bid for a quantity of ZRCs for all four seasons that would be accepted in totality, rather than separate bids for each season.

The Agency received only one stakeholder response which came from Ameren Illinois.[197] Ameren's response states the following:

- Ameren Illinois believed that the implementation of a sloped demand curve should not change the IPA's approach to hedging capacity.
- Ameren Illinois believed that the current hedge percentages for capacity are currently set at an appropriate level. Ameren indicated that they could support the idea of hedging in additional forward years if the Agency feels there is a market for such a product.
- Ameren Illinois supported the notion of using a tiered benchmark approach as long as the Agency continues to follow all the rules that are applicable to the procurement process and benchmarks are established in a thoughtful manner.
- Ameren Illinois did not believe at this time that any special considerations should be made for renewable resources or demand response resources.
- Given the lack of cleared ZRCs in recent capacity procurements, Ameren Illinois proposed that the Agency explore and consider the use of financial products for capacity hedging where there would not be an actual purchase of ZRCs, and instead the product could be structured as a "fixed for float swap" contract. Ameren suggested that soliciting for this type of product could attract sellers who would not otherwise be able to participate in capacity procurements. Ameren Illinois recommended a third annual capacity procurement solely for sellers of financial products be conducted in January or early February of each year for the balance of capacity not procured in prior procurements. In supporting this approach, Ameren noted that by the time of this third procurement, sellers would know accreditation values for resources participating in the next MISO PRA, which could provide sellers strategic value for their participation.

[196] See: https://ipa.illinois.gov/content/dam/soi/en/web/ipa/documents/20240610-2025-electricity-procurement-plan-request-for-stakeholder-feedback-capacity-hedging.pdf.

[197] See comments of Ameren Illinois at https://ipa.illinois.gov/content/dam/soi/en/web/ipa/documents/20240710-aic-response-capacity-hedging.pdf.

- Ameren Illinois supports the idea of including the ability to bid on an annual combination product if the price benchmarks are established in a thoughtful manner.

The IPA appreciates the comments of Ameren Illinois. The development of benchmarks is a confidential process, and the IPA intends to work with its Procurement Administrator on considering how to implement tiered benchmarks for capacity. The IPA will also work with the Procurement Administrator to introduce the ability to bid on annual combination products for capacity (as is already done for energy).

Further, when the IPA released the draft 2025 Electricity Plan on August 15, 2024, the Agency sought feedback from stakeholders about using financial products for capacity hedging where there would not be an actual purchase of ZRCs. Instead, the financial product could be structured as a swap contract, or an agreement between two parties for the exchange of cash flows or liabilities of two different financial instruments.

The Agency was interested in responses to the following questions and used the feedback it received to inform the approach included in this Plan filed for ICC approval. In the draft Plan, the Agency posed the following questions:

1. Do stakeholders agree with the IPA's analysis that this type of swap contract would be permissible under the provisions of the IPA Act and the PUA given the requirement to procure "standard wholesale products" as interpreted by the ICC in prior dockets approving IPA Procurement Plans?
2. Are there other types of financial products other than this structure of a swap contract that the IPA should consider? If so, what would be the advantages of those products compared to a swap contract or the traditional procurement of ZRCs?
3. Are there likely to be sellers who would be interested in bidding on a financial product who would not participate in a procurement for ZRCs? Would the procurement of a financial product increase participation in IPA administered capacity procurements?
4. With this Plan scheduled to be approved by the ICC in mid-December 2024, is it realistic to conduct a procurement in January or February of 2025, or should the IPA continue to develop this new procurement category, including contract development and outreach to potential bidders, for planned implementation in early 2026 (subject to approval in the 2026 Procurement Plan)?
5. Would the procurement of a financial product structured as a swap contract trigger any concerns related to the Sarbanes-Oxley Act, the Dodd-Frank Act, or any additional statutory or regulatory reporting, tracking, or disclosure requirements? If so, on whom would those requirements fall and what additional burdens may be imposed by these requirements?

The Agency appreciates the comments of two stakeholders, Ameren Illinois and Vistra Corp ("Vistra"), that it received on this topic. Both stakeholders support use of financial products, such as swap contracts,[198] for capacity hedging. Ameren Illinois asserted that swap contracts would meet the requirements of standard wholesale products under the provisions of the IPA Act and the PUA.[199] Ameren Illinois explains there are likely to be sellers who would be interested in bidding on a financial product who would not participate in a

[198] The Dodd-Frank definition of a "swap" means any agreement, contract, or transaction (i) that is a put, call, cap, floor, collar, or similar option of any kind that is for the purchase or sale, or based on the value, of one or more interest or other rates, currencies, commodities, securities, instruments of indebtedness, indices, quantitative measures, or other financial or economic interests or property of any kind; (ii) that provides for any purchase, sale, payment, or delivery (other than a dividend on an equity security) that is dependent on the occurrence, nonoccurrence, or the extent of the occurrence of an event or contingency associated with a potential financial, economic, or commercial consequence; (iii) that provides on an executory basis for the exchange, on a fixed or contingent basis, of one or more payments based on the value or level of one or more interest or other rates, currencies, commodities, securities, instruments of indebtedness, indices, quantitative measures, or other financial or economic interests or property of any kind, or any interest therein or based on the value thereof, and that transfers, as between the parties to the transaction, in whole or in part, the financial risk associated with a future change in any such value or level without also conveying a current or future direct or indirect ownership interest in an asset (including any enterprise or investment pool) or liability that incorporates the financial risk so transferred, including any agreement, contract, or transaction commonly known as (the different types of swaps listed in I-XXII); (iv) that is an agreement, contract, or transaction that is, or in the future becomes, commonly known to the trade as a swap; (v) including any security-based swap agreement which meets the definition of swap agreement as defined in section 206A of the Gramm-Leach-Bliley Act[198] of which a material term is based on the price, yield, value, or volatility of any security or any group or index of securities, or any interest therein; or (vi) that is any combination or permutation of, or option on, any agreement, contract, or transaction described in any of clauses (i) through (v). Dodd-Frank Wall Street Reform and Consumer Protection Act, Pub. L. No. 111-203, § 929-Z, 124 Stat. 1376, 1666-1667 (2010).

[199] See comments of Ameren Illinois at https://ipa.illinois.gov/content/dam/soi/en/web/ipa/documents/20240917-2025-ipa-draft-procurement-plan-aic-comments-final-091624-v2.pdf.

procurement for ZRCs, thus the IPA procuring financial products would create opportunities to sellers without physical assets that are interested in participating in IPA procurements.[200] Ameren Illinois believes that a January or February 2025 IPA procurement event of financial products is achievable.[201]

Vistra's comments indicate support for allowing financial products in the IPA's capacity procurement process. Vistra believes this will increase participation in the Agency's procurement events and will lead to more competitive capacity procurements, greater market liquidity, and more favorable procurement outcomes.[202] Vistra explained that there are many capacity market participants, such as major financial institutions and funds, which frequently engage in financial swap transactions—including structuring and executing financial capacity swap contracts— but have little or no interest in participating in physical capacity transactions. Vistra believes that providing a vehicle for such entities to participate in the capacity procurement process through financial capacity transactions will increase the level of participation in the IPA's procurement events and will provide the benefits that will enhance the quality of the IPA's capacity acquisition for Ameren Illinois. However, Vistra does not believe that an additional capacity procurement event in January or February 2025 to procure financial capacity products is needed, given that the IPA plans to conduct two electricity procurement events in 2025 for Ameren Illinois. Vistra explained that additional procurement events and auctions will lead to "auction exhaustion" for participants and bidders. Instead, Vistra recommends that financial capacity product procurements be included in the IPA's regularly-scheduled Spring and Fall procurement events for capacity and energy for Ameren Illinois.

As supported by both stakeholders, the IPA believes that enabling participants to bid financial products, such as swap contracts, in the Agency's capacity procurement events may help the Agency to meet its capacity hedging goals and that procuring financial products may be permissible under the IPA Act and the PUA. Pursuant to Section 16-111.5(b)(3) of the PUA, the procurement plan that the IPA prepares for each Illinois electric utility must include a plan for meeting the expected load requirements that will not be met through preexisting contracts including "the proposed mix and selection of standard wholesale products for which contracts will be executed during the next year, separately or in combination, to meet that portion of its load requirements not met through preexisting contracts."[203] Section 16-111.5(b)(3)(iv) defines standard wholesale products to include monthly 5 x 16 on-peak period block energy, monthly off-peak wrap energy, monthly 7 x 24 energy, annual 5 x 16 energy, other standardized energy or capacity products designed to provide eligible retail customers benefits from commercially deployed advanced technologies including but not limited to high voltage direct current converter stations, as such term is defined in Section 1-10 of the Illinois Power Agency Act, whether or not such product is currently available in wholesale markets, annual off-peak wrap energy, annual 7 x 24 energy, monthly capacity, annual capacity, peak load capacity obligations, capacity purchase plan, and ancillary services."[204]

Though the Commission has not considered the question of whether financial products fit within the statutory definition of standard wholesale products, some previous Commission findings are instructive on the matter. In Docket No. 13-0546 approving the Agency's 2014 Electricity Plan, a party proposed that the Plan be revised to include the Agency procuring full requirements products to meet ComEd's eligible retail customers' service load. The Commission considered whether full requirements products should be considered a standard wholesale product under Section 16-111.5 and held that, "while the statute does not single-out full requirements products as among those considered to be standard wholesale products, the list [in Section 16-111.5(b)(3)(iv) of the PUA] that is provided is preceded by the phrase, including but not limited to . . . the Commission notes that full requirements products will still be subject to the same determination of their compliance with the PUA as other standard wholesale products on a case-by-case basis and encourages the IPA to provide any benchmarks it deems necessary to ensure that compliance prior to the procurement of such products."[205]

[200] Id.

[201] Id.

[202] See comments of Vistra at https://ipa.illinois.gov/content/dam/soi/en/web/ipa/documents/20240917-vistra-comments.pdf.

[203] 220 ILCS 5/16-111.5(b)(3).

[204] 220 ILCS 5/16-111.5(b)(3)(iv).

[205] Docket No. 13-0546, Final Order dated December 18, 2013 at 94.

Further, in Docket No. 14-0588 approving the Agency's 2015 Electricity Plan, the Commission found that "standard wholesale products" are products that are traded on a liquid wholesale market, are well understood, and have transparent pricing such that products bid into the IPA's procurement events can be judged and compared solely on price.[206] The Commission found that the "standard wholesale products" list is non-exhaustive and non-static, and it depends on the products that may be traded in wholesale markets at a given time.[207] Based on these Commission findings, the Agency understands that swap contracts, or any other financial product procured for capacity hedging, must have attributes that are consistent with other commonly traded products in the wholesale market, including transparent prices that allow participants a degree of assurance that they are receiving fair market prices.

Additionally, given that the statutory list of standard wholesale products in Section 16-111.5(b)(3) of the PUA is non-exhaustive and non-static, the Agency does not see why swap contracts would not fit in the "other" category of standard wholesale products that benefit to eligible retail customers. The Agency views swap contracts bid in capacity procurements as products designed to provide benefits to eligible retail customers because the adding this new financial product in IPA administered capacity procurements will increase bidder participation, will increase in the number of bids, and will increase liquidity resulting in lower cost and stable prices over time.

Accordingly, the Agency proposes to include the procurement of a financial capacity products structured as a fixed-for-float swap ("Financial ZRC") in addition to taking bids for the delivery of ZRCs. While a swap product would not actually be a contract for ZRCs, the settlement prices of the swap contracts would be based on the prices of ZRCs from the MISO PRA. For example, if the swap contract price for a given season was $10 and the MISO PRA for that season was $5, the seller would be paid $5. If the MISO PRA for the season was $15, then the seller would pay Ameren Illinois $5. No transfer of ZRCs between the seller and Ameren Illinois would occur.

As stated in the stakeholder support for including financial products in the IPA administered procurement events, enabling bidders to bid in financial products could increase options for prospective bidders to bid in swap contracts, which could result in higher bidder participation in the IPA's capacity procurement events which previously saw low bidder participation and resulted in a lack of cleared ZRCs in Ameren Illinois.

Most recently, the IPA conducted a capacity procurement event on September 13, 2024 to procure seasonal ZRCs for Ameren Illinois for the Delivery Year starting June 1, 2025 and the Delivery Year starting June 1, 2026. To fulfill any unmet capacity targets for those delivery years, Ameren Illinois proposed that the Agency could conduct a procurement event in January or early February of 2025 to procure a financial product that would serve to make up the difference between the amount of capacity procured compared to its capacity hedging goals for the year.[208] However, the Agency agrees with Vistra (as described above) that the timing of an additional procurement in early 2025 would likely not be effective and could lead to bidder exhaustion or confusion. For this Plan filed for ICC approval, the Agency is not including the additional procurement in early 2025.

Instead, the IPA proposes to include the financial capacity product in its customary Spring and Fall capacity procurement events scheduled for 2025. The IPA, through its Procurement Administrator, will simultaneously analyze bids received for the traditional physical capacity product (ZRCs) and bids received for the financial capacity product (Financial ZRC) and select the least cost alternative, up to the procurement target for each of the delivery years being procured.

Finally, the draft 2025 Electricity Plan sought stakeholder feedback on whether the procurement of a financial product structured as a swap contract would trigger any concerns related to the Sarbanes-Oxley Act, the Dodd-Frank Act, or any additional statutory or regulatory reporting, tracking, or disclosure requirements. Ameren Illinois commented that the reporting requirements should be determined on a case-by-case basis by each party that participates in the procurement event and that such reporting requirements should not preclude the

[206] Docket No. 14-0588, Final Order dated December 17, 2014 at 156.

[207] Id.

[208] See comments of Ameren Illinois at https://ipa.illinois.gov/content/dam/soi/en/web/ipa/documents/20240917-2025-ipa-draft-procurement-plan-aic-comments-final-091624-v2.pdf.

IPA from considering the proposal to procure financial products. The IPA agrees with Ameren Illinois that such reporting requirements, as detailed in the Dodd-Frank Act of 2010, and are solely administrative requirements that should not prevent the IPA from including swap contracts in its procurements.

For the reasons stated above, the Agency respectfully seeks the Commission's approval to include financial products, including swap contracts, in IPA administered procurements for capacity hedging.

5.2.1.7 Capacity Hedging Strategy for Ameren Illinois

In the IPA's 2023 Electricity Procurement Plan, the Agency made an adjustment to its capacity hedging strategy for the 2024-2025 and 2025-2026 Delivery Years by adopting a hedging strategy of procuring up to 75% in the IPA's bilateral procurements and the balance in the PRA.[209] The 75% would be equally applied to all four seasons in the IPA's procurements. In adopting the adjusted hedging strategy, the IPA noted that a 75%/25% procurement strategy would mostly hedge Zone 4 eligible retail customers in the event of another price shock in the PRA; however, it would also allow the customers to benefit if the PRA clears at a price that is lower than the price in the IPA's bilateral procurements. The IPA decided not to propose any changes to the 75%/25% procurement strategy in its 2024 Electricity Procurement Plan after reviewing the results of the 2023-2024 PRA.

For the 2025 Electricity Procurement Plan, the Agency conducted a stakeholder feedback process as explained in Section 5.2.1.6. After reviewing the stakeholder response, for this Plan, the IPA has decided to maintain the current hedging strategy. The IPA will therefore continue with the 75%/25% procurement strategy and apply it to the 2026-2027, 2027-2028, and 2028-2029 Delivery Years. As discussed in the previous section, the Agency proposes including the option for the procurement of a financial swap contract product in the two procurement events for capacity for Ameren Illinois.

More details on the hedging strategy are provided in Section 7.2. For the 2025 Plan, the Agency will use a consistent hedging level across all four seasons. As future year results of MISO seasonal capacity auctions become available, the Agency will analyze the results of those auctions and may propose changes in seasonal hedging levels in future Plans.

[209] See discussion in the IPA's 2023 Electricity Procurement Plan in Section 5.2.2.2.4.

6 Managing Supply Risks

The Illinois Power Agency Act lists the priorities applicable to the IPA's portfolio design, which are "to ensure adequate, reliable, affordable, efficient, and environmentally sustainable electric service at the lowest total cost over time, taking into account any benefits of price stability."[210]

At the same time, the Legislature recognized that achievement of these priorities requires a careful balancing of risks and costs, when it required that the Procurement Plan include:

> *an assessment of the price risk, load uncertainty, and other factors that are associated with the proposed procurement plan; this assessment, to the extent possible, shall include an analysis of the following factors: contract terms, time frames for securing products or services, fuel costs, weather patterns, transmission costs, market conditions, and the governmental regulatory environment; the proposed procurement plan shall also identify alternatives for those portfolio measures that are identified as having significant price risk.*[211]

Public Act 102-0662 adjusted the Procurement Plan priorities of the IPA by adding:

> *…mitigation in the form of additional retail customer and ratepayer prices, reliability, and environmental benefits from standardized energy products delivered from commercially deployed advanced technologies, including, but not limited to, high voltage direct current converter stations, as such term is defined in Section 1-10 of the Illinois Power Agency Act, whether or not such product is currently available in wholesale markets…*

This Chapter discusses and assesses risk in the supply portfolio, as well as tools and strategies for mitigating the relevant risks. Developing a risk management strategy requires knowledge of the risk factors associated with energy procurement and delivery, and of the tools available to manage those risks. Section 6.1 describes the relevant risk factors. Sections 6.2 and 6.3 describe the tools for managing supply risk and the types of contracts and hedges that can be used to manage supply risk. Those products provide the basis for building the supply portfolio. The IPA's review of high voltage direct current ("HVDC") transmission and the assessment of the applicability of HVDC products as part of the Agency's procurement and hedging approach are also discussed in Section 6.3. Section 6.4 addresses the complementary issue of reducing or re-balancing the supply portfolio when needed, and the legal, regulatory and policy issues that may arise if utilities must do so by selling previously purchased hedges. Section 6.5 provides a historical summary of the Ameren Illinois, ComEd, and MidAmerican Purchased Electricity Adjustment ("PEA") rates as a guide to the historical impact of risk factors.[212] This section also addresses the changes in MidAmerican pricing that reflect the costs of participating in the IPA procurements. Section 6.6 discusses the IPA's historical approach to risk and portfolio management as well as the hedging considerations going forward. Section 6.7 describes the number and timing of the IPA's procurement events. Section 6.8 addresses the role of demand response programs in risk management. Finally, Section 6.9 provides a discussion of the use of Carbon Mitigation Credits to offset the reduction of the IPA's energy hedging targets including a review of the relative cost of the offsetting benefits provided by CMC contracts.

Section 6.6.2 addresses the cost and uncertainty impacts of supply risk factors. Risk is often taken to mean the amount by which costs differ from initial estimates. Utility energy pricing in Illinois for Ameren Illinois and ComEd customers is based on estimates and cost differences which are trued up after the fact through the PEA. Prior to the 2016-2017 Delivery Year, MidAmerican provided power and energy to its eligible Illinois customers entirely from MidAmerican owned generation, with energy costs for MidAmerican customers in Illinois recovered through base rates regulated by the ICC. Starting with the 2016-2017 Delivery Year, MidAmerican pricing for its Illinois customers also included the cost of energy obtained in IPA procurements through its PEA, which reflects a cost recovery process similar to what is used by Ameren Illinois and ComEd.

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[210] 20 ILCS 3855/1-20(a)(1).

[211] 220 ILCS 5/16-111.5(b)(3)(vi).

[212] See 220 ILCS 5/16-111.5(l). This policy is manifest through riders filed by each utility – ComEd's Rider PE (Purchased Electricity), and Ameren Illinois' Rider PER (Purchased Electricity Recovery).

6.1 Risks

Procurement risk factors can be divided into three broad categories: volume, price, and hedging imperfections. Volume risk deals with risk factors associated with identifying the volume and timing of energy delivery to meet demand requirements. Price risk covers not only the uncertainty in the cost of the energy but also the costs associated with energy delivery in real time. Hedging imperfections are the result of mismatches between the types of available hedge products and the nature of customer demand.

6.1.1 Volume Uncertainty and Price Risk

The accuracy of load forecasts directly impacts volume uncertainty. Accurate customer consumption profiles, load growth projections, and weather forecasts impact both the total energy requirement and the shape of the load curve. Chapter 3 describes the load forecasting processes utilized by Ameren Illinois, ComEd and MidAmerican. The risk factors that determine overall volume risk include changes in customer load profiles and usage patterns, the uncertainties associated with load growth and short-term weather fluctuations, technology changes such as smart meters and behind the meter generation and storage, and customer switching. For the Illinois utilities, a key factor in volume risk is the uncertainty associated with customer switching which directly impacts the results of the utilities' load forecasts. The opportunities for potentially eligible retail customers to take service from ARES or through municipal aggregation resulted in substantial portions of the potentially eligible retail customer load switching away from the utilities toward non-utility retail contracts that ran through the 2014-2015 procurement year. In recent years, prior to the 2022-2023 Delivery Year, the number of residential customers taking ARES or municipal aggregation supply declined. Starting in December 2021 and continuing into early 2024, volatile market conditions and high electricity prices resulted in uncertainty with regard to the level of customer switching experienced by the utilities. Many customers taking service from alternative suppliers during this period also experienced volatile electricity supply prices ranging from well below to significantly above their default electric service cost, generating unprecedented uncertainty for attempts to forecast customer switching levels. From December 31, 2023 through June 30, 2024, the number of residential customers taking fixed price supply service from the utilities declined 8.31% for ComEd and 1.31% for Ameren Illinois.[213] The primary uncertainty surrounding customer switching going forward is related to how the recent switching patterns will settle and the potential for additional retail load migration back to or away from the utilities. The key switching assumptions for customer switching affecting the utilities' load forecasts are described in detail in Chapter 3 of this Plan. Customer switching decisions are influenced by the difference between utility and third-party pricing.

Customer switching behavior impacts volume risk and, in turn, variability in utility customer volumes impacts price risks. The IPA's historical procurement strategy involves buying power in a "laddered" approach with a large fraction of the power to serve retail customers in the delivery year procured through forward purchases over a three-year procurement horizon. In a period of rising prices, those forward purchases are likely to be priced below market. Therefore, the blended price of utility supply may be less than the current price of an ARES offer, even an offer through municipal aggregation. This price difference can result in increased customer migration back to the utility. The reverse can occur as well; higher utility supply costs relative to alternatives through ARES suppliers or municipal aggregation can result in eligible retail customers migrating away from the utilities.

6.1.2 Residual Supply Risk

Hedging imperfection can contribute to supply risks through mismatches in procurement supply shape, supply delivery points, and customer load locations. The standard on-peak and off-peak block energy products procured by the IPA do not reflect the variation in hourly loads. These products provide constant volumes and prices across a fixed number of hours while hourly prices as well as load vary across the day and within each of the on-peak and off-peak periods. Because of this variation, even if the average on-peak and off-peak monthly load is perfectly hedged, the actual hourly load will still be imperfectly hedged. Residual supply risk will remain since the actual load will vary between being greater than or less than the average.

213 See: Illinois Commerce Commission, Office of Retail Market Development, Industry Reports, Electric Switching Statistics at https://www.icc.illinois.gov/ormd/reports-and-statistics.

6.1.3 Basis Differential Risk

Basis differential risk relates to the uncertainty that the price of energy at a given pricing point is not the same as the settlement price at the point(s) or zone where the energy is ultimately consumed. Locational mismatches are generally not a risk for the IPA procurements since the delivery points for the hedge contracts are the LSE's load zone.

6.2 Tools for Managing Supply Risk

Traditionally, a utility's electricity supply plan includes physical supply and financial hedges. Physical supply includes the power plants that the utility owns or controls, as well as transactions for physical delivery of electricity. Financial hedges are additional hedging instruments used to manage price risk and other risks, such as weather risk.

Following the enactment of the Electric Service Customer Choice and Rate Relief Law (Public Act 90-0561) in 1997, ComEd and Ameren Illinois divested their generating plants to unregulated affiliates or third parties. ComEd and Ameren Illinois have no contracts for unit-specific physical delivery, other than certain Qualifying Facilities (as designated under the federal Public Utilities Regulatory Policies Act) contracts. The utilities' supply positions, other than RTO spot energy purchases, are exclusively price hedges. MidAmerican has retained the resources that serve its Illinois customers; most of these resources are located outside of Illinois. MidAmerican allocates a portion of the capacity and energy from specified resources under its control for its Illinois eligible retail customers. Prior to the 2016 Plan procurements, the allocated capacity and energy from MidAmerican owned resources were sufficient to meet the needs of MidAmerican's Illinois eligible retail customers. Current and planned retirements among these resources are reducing the capacity available for allocation to MidAmerican's Illinois customers. As a result, MidAmerican requested that the IPA procure the portion of energy and capacity that is not forecasted to be met by the Illinois-allocated MidAmerican resources. Following the approach started for the 2016 Plan, and continued under subsequent Plans through the 2024 Plan, for the 2025 Plan, the IPA will procure the net energy requirements between MidAmerican's eligible retail customer load and the MidAmerican controlled generation allocated to its Illinois customers. The portion of MidAmerican's capacity requirements for eligible retail customers in Illinois not covered by MidAmerican's owned resources will be procured through the MISO PRA.

ComEd's capacity requirements will continue to be obtained through the PJM-Administered capacity market (absent any legislative changes). Prior to the 2023 Plan, the Ameren Illinois capacity needs had been procured through a combination of IPA procurements for 50% of its needs in the near-term forward market with the remaining balance obtained through the MISO PRA. Starting with the 2023 Procurement Plan, and continuing with the 2024 Plan, the IPA proposed to procure up to 75% of these needs through the IPA procurements, with the balance to be procured through the PRA. This 75% capacity procurement target for Ameren Illinois has been retained for the 2025 Plan.

Physical electricity supply and load balancing for ComEd, Ameren Illinois, and MidAmerican are coordinated by the respective RTOs (PJM for ComEd and MISO for Ameren Illinois and MidAmerican). ComEd, Ameren Illinois, and MidAmerican are considered to be LSEs by the RTOs. Each RTO provides day-ahead and real-time electricity markets and clearing prices. The generators supply their energy to the RTO, and the RTO delivers energy to LSEs and customers. The RTO ensures the physical delivery of power. The cost of managing this delivery, including the cost of managing reliability risks, is passed on to the LSEs financially. The risks faced by LSEs in supplying energy to customers are mostly financial. The LSEs still need to manage certain operational risks such as scheduling and settlement. There are other non-financial risks associated with electricity retailing, such as customer billing or accounts receivable risks, but those are not associated with the supply portfolio.

Each RTO charges a uniform day-ahead price for all energy scheduled to be delivered in a given hour and delivery zone. To the extent that real-time demand differs from the day-ahead schedule, load is balanced by the RTO at a real-time price: if demand exceeds the day-ahead schedule, then the LSEs pay the real-time price; and if demand is less than the day-ahead schedule, the LSEs are credited with the real-time price. Both the day-ahead and the real-time prices are referred to as Locational Marginal Prices ("LMPs") because they depend on the delivery location or zone.

6.3 Types of Supply Hedges

The 2014 Procurement Plan contained a detailed description of a number of different types of supply hedges, which are listed below. One point made in that Plan is that hedges available in the market are not perfect; the risks listed in Section 6.1 cannot all be hedged away except perhaps through a specially tailored "full requirements" hedge contract, whose price premium may not be acceptable in return for that degree of risk mitigation.[214]

An important category of energy supply hedges is a unit-specific supply contract. Other supply hedges are forward contracts, futures contracts, and options.

Unit-Specific Hedges

Unit-specific hedges are tied to the output of a specific generating unit which can depend on how the unit is dispatched, including contracts that fall into the following categories:

- As-available
- Baseload
- Dispatchable

Unit-Independent Hedges

Other energy supply hedges are available that are not dependent on the operation of a specific generating unit including:

- Standard forward hedges (block contracts)
- Shaped forward hedges
- Futures contracts
- Options
- Full requirements hedges

6.3.1 Suitability of Supply Hedges

Not all of the types of hedges listed in Section 6.3 are suitable for use in this Procurement Plan, and not all may be readily available in electricity markets.[215] Illinois law requires that "any procurement occurring in accordance with this plan shall be competitively bid through a request for proposals process," provides a set of requirements that the procurement process must satisfy, and mandates that the results be accepted by the ICC.[216] Among the specific requirements, the Procurement Administrator must be able to develop a market-based price benchmark for the process; the bidding must be competitive; and the ICC's Procurement Monitor is required to report on bidder behavior.[217] The level of bidding competitiveness can be gauged by the breadth of participation by bidders in the procurement.

Hedges most suitable for use by the Agency are those standardized products that are well-understood, and preferably widely traded. If a product has liquid trading markets, or is similar to other products with liquid markets, a bidder can manage its risk exposure. The availability of information on current prices and the price history of similar products helps bidders provide more competitive pricing and helps the Procurement Administrator produce a realistic benchmark. Prior to its 2014 Procurement Plan, the IPA had generally restricted its hedging to the use of standard forward energy hedges in 50 MW increments. The IPA began using

[214] Even a full requirements hedge does not truly eliminate all risk. For example, if a supplier of a full requirements tranche were to default, additional procurement costs to make up the shortfall could be passed along to eligible retail customers.

[215] There had been substantial debate in the approval of certain past Procurement Plans related to whether a full requirements approach is a more suitable approach for eligible retail customers. In approving the 2015 Plan and rejecting the Illinois Competitive Energy Association's full requirements procurement proposal as "not supported by the record," the Commission stated that it "wishe[d] to make clear that it is not inclined to consider future years' full requirements procurement proposals absent new arguments supported by an analysis quantifying benefits to eligible retail customers." Docket No. 14-0588, Final Order dated December 17, 2014 at 114. Since that decision, the IPA is not aware of any new arguments in favor of full requirements (let alone new arguments supported by analyses quantifying benefits to eligible retail customers) and notes the success of its procurement approach in producing competitive supply rates for Ameren Illinois, MidAmerican, and ComEd eligible retail customers.

[216] 220 ILCS 5/16-111.5(b), (e), (f).

[217] 220 ILCS 5/16-111.5(f)

25 MW increments and a second, fall energy procurement with the 2014 Plan. The Agency's recommended plans have been stated in terms of monthly contracts, although procurement events have met some of these needs with multi-month contracts.

The IPA has in the past purchased energy products that are not typically traded, such as the long-term PPAs with new-build renewable generation that were authorized in the 2010 Procurement Plan. These products still must be standardized in such a way that the winning bidders may be selected based on price alone, and the price is subject to a market-based benchmark. As discussed in Chapter 2, while the ICC clarified its understanding of the definition of "standard wholesale product" in its approval of the 2014 and 2015 Procurement Plans, the IPA's authority to procure other products, including shaped forward contracts and option contracts, could be subject to future litigation. Markets for products that are specifically designed for the IPA's requirements, such as full requirements contracts or over-the-counter options, will likely have limited transparency. The IPA's procurement structure requires a benchmarking and approval process which may not be compatible with such a low level of transparency.

Quoted prices for energy futures contracts at the PJM Northern Illinois Hub and the MISO Illinois Hub provide reasonable indications of the future prices anticipated by the market, making such contracts easier to benchmark. The markets for long-dated (i.e., further in the future) contracts are generally less liquid than the markets for near-term contracts, however. The Agency would need to obtain competitive pricing on such contracts if it were to incorporate them in its supply portfolio. However, it would be difficult or impossible to conduct the statutory RFP process for exchange-traded futures contracts: setting a price through an RFP process structured per legislative mandates is incompatible with price-setting in an open outcry auction, through electronic trading or by a market-maker. It is also unclear how the margin requirements would fit within the current regulatory framework if price movements require the utility to post margin many months in advance of delivery. The same concerns are even more applicable to options contracts.

Section 16-111.5(b)(3)(iv) of the Public Utilities Act provides that procurements of standard wholesale products may include energy from HVDC transmission lines that would have converter stations located in Illinois. To the extent such products qualify to participate in the IPA's procurement events, HVDC products are to be treated on a comparable basis with other sources of supply utilized in the IPA's hedging strategy and procurement process.

For this 2025 Plan, the IPA reviewed the development status of potential HVDC projects to assess the HVDC products that could be used by the Agency as a suitable risk management tool. The IPA's review identified several issues and uncertainties that would have to be addressed prior to incorporating HVDC products into the IPA's risk management strategy and an IPA Procurement Plan, including:

The SOO Green HVDC link, currently under pre-construction development, would involve a 350-mile long, 525 kV, bidirectional transmission line capable of transmitting 2,100 MW from a point near Mason City, Iowa in MISO to a point on the ComEd transmission system near Yorkville, Illinois in PJM. The commercial operation date for this project has been delayed several times. The current anticipated initial operation date is now 2030.[218] The uncertainty regarding the project's commercial operation date raises the issue of timing as to when the IPA would be able to consider products from the HVDC project for inclusion in the procurement process.

If the SOO Green HVDC transmission link is constructed it would offer a path for the transmission of wholesale energy, but the project will seek to also be compensated for the value of its capacity. Since the proposed terminus of the line would be in PJM, the IPA would only be procuring energy for ComEd's eligible customers that would be delivered through the HVDC line not capacity. This raises additional uncertainties regarding how this product could be incorporated in the IPA procurement process and still provide sufficient revenues to help make the project economically viable. In its recent Policy Study,[219] the IPA analyzed a policy to establish a procurement for RECs from a high voltage direct current transmission line, including a review of the potential

[218] See: Illinois Power Agency Policy Study. SOO Green HVDC Link Comments, p.23 https://ipa.illinois.gov/ipa-policy-study/stakeholder-feedback-on-draft-policy-study.html .

[219] See https://ipa.illinois.gov/ipa-policy-study.html.

costs to ratepayers, the impact on grid reliability and impact on resource adequacy in Illinois of the proposed SOO Green HVDC line.

Another proposed HVDC line under development, the Grain Belt Express HVDC line, is proposed as a nominally 600 kV line with a capacity of 5,000 MW that would run from Ford County, Kansas to an interconnection in MISO in Missouri in the project's first phase. The second phase of the project would involve 2,500 MW of the line's capacity to be delivered to a converter station in Clark County, Illinois with further deliveries along a 345 kV AC transmission line to a termination point in Sullivan County, Indiana.[220] The first phase of this HVDC line is scheduled to start construction in 2025 with the first year of operation currently anticipated for late 2029.[221] The schedule for the construction and operation of Phase 2 has not been announced.

Merchant HVDC projects, such as the projects referenced above, typically require long-term transmission contracts with terms of 15 to 20 years to be signed ahead of financing and construction. Since the IPA's procurement horizon is focused on three years, such long-term contracts do not fit into the IPA's statutorily defined procurement process.

Questions related to these issues were posed in the draft 2023 Procurement Plan, but no parties offered comment in response. As a consequence, the 2023 Plan did not offer resolution on these issues and uncertainties. While these issues remained unresolved for the 2024 Plan and for the 2025 Plan, the uncertainty around the in-service dates of the two HVDC projects products pushes the delivery of HVDC electricity products beyond the planning horizon for this Plan. The IPA also understands that the most recent legislative discussions around supporting at least the Soo Green HVDC project have focused on utilizing long-term REC delivery contracts as the means for providing revenue certainty, and not on the procurement of standard wholesale products (such as energy or capacity).

6.3.2 Options as a Hedge on Load Variability

An option gives the buyer a right but not an obligation to buy or sell a commodity at a specified price on or before a certain date. For example, a call option gives the buyer the right, but not the obligation, to buy a specific contract. A put option gives the buyer the right, but not the obligation, to sell a specific contract. Options are "one-way" hedges. A call option, for example, can help hedge against price increases but provides no hedge against price decreases. Options on forward or futures contracts are much less expensive than the contracts themselves because they only convey the right to buy or sell the contract for the commodity at a specified strike price.

Options can be perceived as attractive tools to hedge against customer migration and other forms of load fluctuations. According to option pricing theory, options are not any more useful for hedging price risk than are forward contracts unless one is exposed to other risks that correlate with and enhance price risk (for example, loss of load accompanied with declining prices). In theory, option prices are determined by the value of the option as a price hedge. If an option had additional value as a hedge against load migration risk, some might consider options to be a bargain. It turns out that options are expensive when used as hedges for load migration risk. This is because if a call option on 1 MW of load has a price V, then that should be its value as a price hedge. If the 1 MW is not currently served by the utility, but may return with some probability P, then the value of this option should be only P times V which is less than its price. In other words, the value of the option as a hedge against load migration risk is less than its value as a price hedge. But it is the value as a price hedge that determines the option's price.

There are also other costs and logistical obstacles to using options:

- A large part of the volume of options on the market is traded on exchanges. They have a particular advantage in that the trading exchange bears the counterparty default risk. However, the Agency's structured procurement process prevents the Agency from buying options on the exchanges.
- Option contracts can be relatively illiquid, making it more difficult to assure fair pricing. If options purchased through the IPA procurement process required an affirmative exercise decision, which most likely they would, the utilities would seek regulatory comfort on their exercise decision-

[220] See Illinois Commerce Commission March 8, 2023 Order in Docket No. 22-0499.

[221] "Grain Belt Express Launches Open Solicitation Process to Offer HVDC Transmission Line Capacity Delivery to MISO/AECI." March 2024. https://grainbeltexpress.com.

making before agreeing to use options. For example, if an exercise decision were dependent on the utility's load forecast or view of municipal aggregation, the utility would want to be able to show it had acted prudently. If the utility exercised a put option, to sell the underlying hedge, it would want to be sure that decision did not make it a wholesale market participant for purposes of FERC Order 717. If the option exercise were purely financial and automatic—resulting only in a cash payment from the option holder—these concerns might not be as important, but counterparty credit would be an issue.

The use of options is subject to regulations under the federal Dodd-Frank Act of 2010 (specifically Title VII).[222] Under the Dodd-Frank Act, the trading of options (and other swaps) would be reported to a central database for clearing purposes. Trade details (price, volumes, time stamped trade confirmations, and complete audit trails) would need to be reported. In addition, trade records must be kept for five years after the termination of trade (either through exercise or expiration) and must be made available within five business days of request. This would add to either the purchase cost or the ownership cost of options.

6.4 Tools for Managing Surpluses and Portfolio Rebalancing

The Illinois Power Agency Act specifies that the Procurement Plan "shall include … the criteria for portfolio re-balancing in the event of significant shifts in load."[223] It is therefore appropriate to consider what tools are available to conduct such rebalancing, keeping in mind that the utilities, not the Agency, are the owners of the forward hedges and that selling of excess supply in the forward markets may have unintended cost and accounting consequences.

- To date, the only rebalancing of hedge portfolios prior to the delivery date has been the curtailment of long-term renewable contracts due to budget restrictions. Spending on these contracts was subject to a limit related to a statutorily mandated rate impact cap calculated based on eligible retail customer load, making the budget available for payment under those contracts subject to fluctuation due to load migration away from (and back to) utility supply.[224]

- Sales of excess supply by the utilities via a reverse RFP to rebalance their supply portfolio may create a de facto "wholesale marketing function" within the utilities. The employees involved in wholesale marketing activities would be subject to the separation of functions in accordance with FERC Order 717.[225]

- To date, the utilities have scheduled excess supply in their portfolios, or made-up supply deficits in the RTOs' day-ahead markets with residual balancing occurring in the RTOs' real-time markets. This has been the dominant mode of portfolio rebalancing.

- As an alternative form of rebalancing, the Agency could conduct "reverse RFP" procurement events, in which the bids are to buy rather than sell forward hedges. The Agency does not believe that it has the authority to sell excess supply via its authority to "conduct competitive procurement processes" under 20 ILCS 3855/1-20(a)(2).

- The Agency could conceivably issue an RFP to purchase derivative products, such as put options on forward hedges, which would have a similar risk reduction effect to selling forwards. This may avoid legal and contractual difficulties associated with selling forward hedge contracts. This approach would also require the utilities to ensure they had regulatory approval to exercise the options after purchasing them, and the employees who exercise the option could become classified as part of a "marketing function." The Agency does not envision entering into derivative contracts for rebalancing purposes.

- The Agency could conduct multiple procurement events in a year if the rebalancing required is to increase the supply under contract. Since 2014, the IPA has conducted two energy procurements each year, one in the spring and the other in the fall. Starting with the 2018 Procurement Plan, the

[222] Pub. Law 111-203, July 21, 2010 (modifying, *inter alia*, the Commodity Exchange Act at 7 U.S.C. § 2).

[223] 220 ILCS 5/16-111.5(b)(4).

[224] As the state's renewable portfolio standard has transitioned to being funded through a charge assessed to all utility retail customers, and as the IPA Act expressly prioritizes "renewable energy credits under existing contractual obligations" in prioritizing limited funding, future curtailment of these agreements is no longer a meaningful risk. (See 20 ILCS 3855/1-75(c)(1)(E), (F)).

[225] 125 FERC ¶ 61,064, Oct. 16, 2008.

IPA began conducting two capacity procurements to cover a portion of Ameren's capacity requirements, one in the spring and one in the fall. Conducting multiple procurements each year provides for a more precise portfolio balance, which is the direct result of using more current load forecasts.

6.5 Purchased Electricity Adjustment Overview

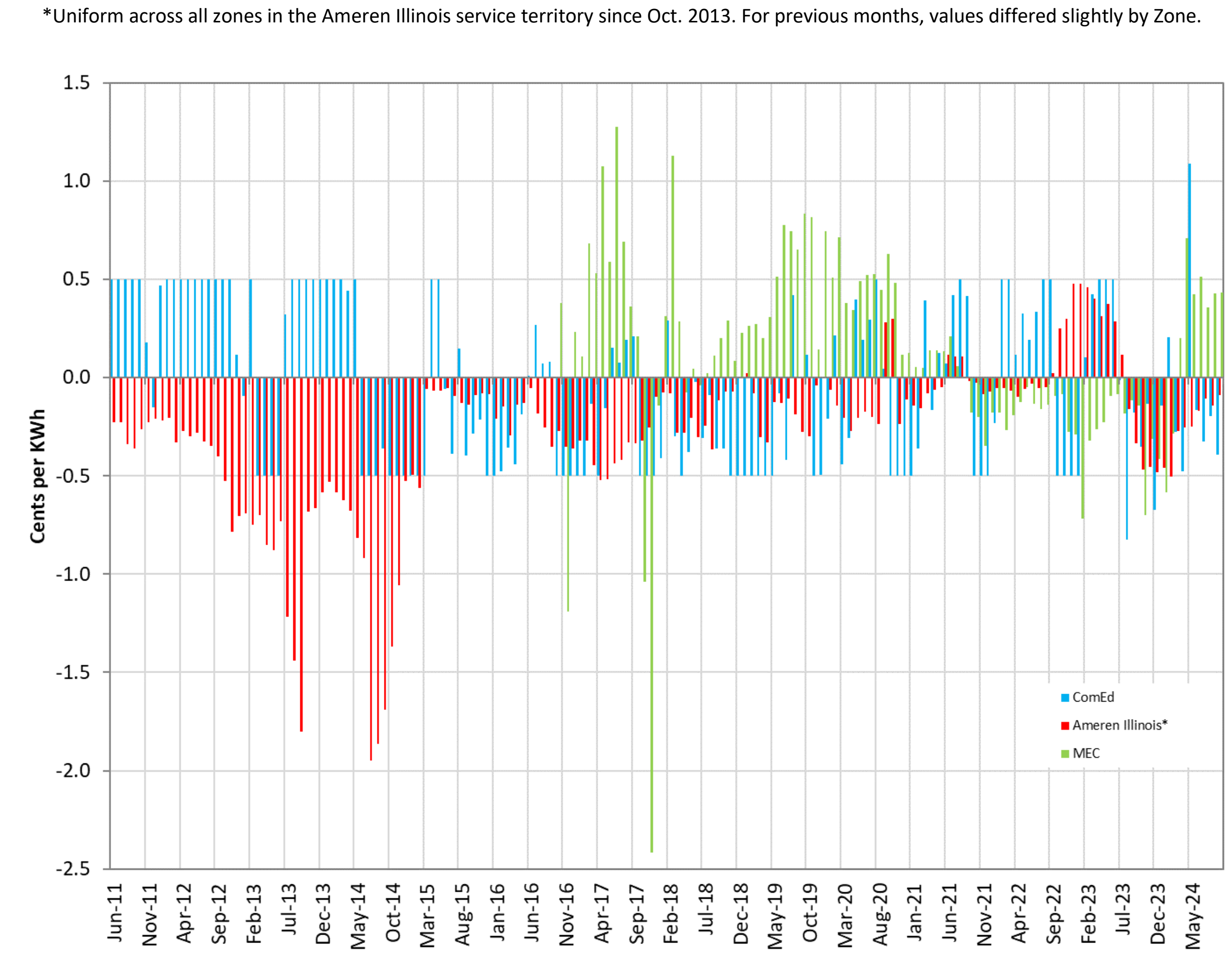
The PEA functions as a financial balancing mechanism to assure that electricity supply charges match supply costs over time. The balance is reviewed monthly, and the charge rate is adjusted accordingly. The PEA can be a debit or credit to address the difference between the revenue collected from customers and the cost of electricity supplied to these same customers in a given period. The supply costs are tracked, and the PEA adjusted, for each customer group. The PEA is applicable to the purchased electricity costs of Ameren Illinois, ComEd, and MidAmerican.

The PEA provides some guidance as to the amount by which the complete set of risk factors caused the cost of energy supply to differ from utility estimates. Figure 6-1 shows how the PEAs for Ameren Illinois and ComEd have changed over the last 13 years. The figure also shows the applicable MidAmerican PEAs starting with October 2016. Ameren Illinois' PEAs have been generally "negative" (i.e., operating as a credit to customers) since the early part of this period with a few positive months until turning positive from September 2022 through July 2023. The Ameren PEA was a negative value from August 2023 through June 2024. ComEd's have been "negative" as well as "positive" (i.e., operating as charge to customers). The MidAmerican PEA exhibited significant volatility from 2016 to 2018, ranging from a negative 2.415 cents/kWh in November 2017 to a positive 1.277 cents/kWh in June 2017 and a positive 1.127 cents/kWh in February 2018. Since then, MidAmerican's PEA has exhibited somewhat less volatility and was consistently positive from July 2018 through August 2021, then turned negative from September 2021 through February 2024, and turned positive again from March 2024 through June 2024.

In April 2014, the Commission approved an adjustment to ComEd's PEA that allows the accumulated balance of deferrals associated with the computation of the PEA each June to be rolled into the base default service rate for the next year and the associated balance to be reset to zero. The ComEd PEA increased from a credit to a charge for April and May of 2015 (due to how the ICC instructed ComEd to recover customer care costs from eligible retail customers, and not due to costs related to energy procurement). Absent that cost recovery, the PEA would have operated as a credit to customers in those two months. Since May 2015, the ComEd PEA has reflected both credits and charges. Through February 2023, ComEd voluntarily limited its PEA to move between +0.5 cents/ kWh and -0.5 cents/kWh. The change to the hedging strategy for ComEd that was implemented by the IPA in 2023, to only procure 50% of expected customers load, means that the ComEd PEA could have larger swings to reflect the cost of electricity purchased from the spot electricity market for the remaining 50% of load. However, that change was made in conjunction with a change to Rider CRFA "(Carbon-Free Resource Adjustment") which is the Rider that reflects the price of Carbon Mitigation Credits on customer bills. As discussed in Section 6.9, changes to the PEA are offset by changes to Rider CFRA.

In the early months of the historical period, notably July 2013 through September 2013 and July 2014 through November 2014, the magnitude of the Ameren Illinois negative PEAs increased significantly. The IPA understands that this change was largely the result of the long position in the supply portfolio of Ameren Illinois resulting from the increase in municipal aggregation switching, and that long position was subsequently settled favorably to customers within the MISO balancing markets. This resulted in an over-collection from eligible retail customers during the previous winters and the large negative PEA values represent the return of those proceeds to the remaining eligible retail customers. Since December 2014, the mostly negative values of the Ameren Illinois PEAs have been much smaller as portfolio volumes have become better matched with actual load. Ameren Illinois' PEA values have been primarily negative (a credit to customers) throughout this period with a few shorter periods of positive values (a charge to customers). Prior to April of 2018, MidAmerican had been including in the PEA factor the entire adjustment amount in a single month, creating significant volatility in the PEA factor. In April of 2018, MidAmerican began amortizing the monthly adjustment amount over multiple months when needed. MidAmerican is using a "soft cap" of +$100,000 to determine if the monthly adjustment amount should be amortized. During the time that the amortization has been used in the calculation, MidAmerican has seen a reduction in volatility with the PEA mostly positive with a period of negative values from in September 2021 through February 2024.

Figure 6-1: Purchased Electricity Adjustments in Cents/kWh, June 2011 – September 2024



6.6 Estimating Supply Risks in the IPA's Historical Approach to Portfolio Management

6.6.1 Historical Strategies of the IPA

The utilities, pursuant to plans developed by the IPA, have historically used fixed-price, fixed-quantity forward energy contracts and financial hedges (such as the LTPPAs), along with RTO load balancing services to serve load. Energy deliveries have been coordinated by the RTOs and the Agency arranged a portfolio of long-term contracts and standard forward hedges. These forward hedges were procured in multiples of 50 MW during the earlier procurements and in 25 MW blocks since 2014. Ancillary services have been purchased from the RTO spot markets. The utilities have used Auction Revenue Rights to mitigate transmission congestion cost.

Forward hedges have been procured on a "laddered" basis. The Agency originally sought to hedge 35% of energy requirements on a three-year-ahead basis, another 35% on a two-year-ahead basis, and the remainder on a year-ahead basis. Prior to 2014, procurements had been annual, in April or May, rather than on a more frequent or ratable basis. For example, in the spring of 2010, the Agency procured forward hedge volumes as close as possible to 35% of the monthly average on-peak and off-peak load forecasts for the 2012-2013 Delivery Year. In the spring of 2011, the Agency procured forward hedge volumes to bring the total volume as close as possible to 70% of then-current monthly average on-peak and off-peak load forecasts for the 2012-2013 Delivery Year. And in the spring of 2012, the Agency procured forward hedge volumes to bring the total volume as close as possible to 100% of then-current monthly average on-peak and off-peak load forecasts for the 2012-2013 Delivery Year. In the 2013 Procurement Plan, the Agency indicated it was considering a change in hedging from 100%/70%/35% of the expected load to 75%/50%/25%. Because there were no procurements in 2013, that hedging strategy was not formally adopted or implemented.

In the 2014 Procurement Plan, the IPA proposed a modification to the 75%/50%/25% strategy. Specifically, the Agency proposed that the procurement goal for a mid-April procurement event should be to hedge 106% of the expected load for the immediately following June-October. These months would be close to the procurement date and no benefit was seen in deferring 25% of the procurement to the spot market. On the other hand, because of the correlation between load and price and because prices in the hours of high usage are more than 100% of the time-weighted average price, a $1/MWh movement in the monthly average price translates into an increase of more than $1/MWh in the average portfolio cost (the load-weighted average price) – in fact, approximately $1.06/MWh. The Agency continued to recommend hedging up to only 75% of the expected load for November-May of the prompt delivery year in the April procurement, but also recommended a second procurement in September to bring the hedged volume for those months to 100%.

In the 2015 Procurement Plan, the IPA adopted some minor changes from the 2014 Plan. The hedge ratios for the April procurement event were adjusted to 100% of the expected load for off-peak hours for June through October delivery in the prompt delivery year and for on-peak hours for June, September, and October delivery in the prompt delivery year. The hedge ratio was left at 106% only for the on-peak hours of July and August The target hedge ratios for delivery in subsequent years were adjusted to 37.5% for all months (June-May) of the following delivery year for the April procurement event, 50% for all months of the following delivery year for the September event, 12.5% for all months of the second delivery year out for the April event, and 25% for all months of the second delivery year out for the September event.

In the 2016 Procurement Plan, other than moving October from the group of months fully hedged in the April procurement to the group of months to be fully hedged in the Fall procurement, no substantial changes to the strategy were implemented, but consideration was given to adjusting the target cumulative hedge ratios for various delivery months, effective at the next to last scheduled event prior to delivery.

For the 2017 through 2024 Procurement Plans, the IPA continued the use of two annual procurement events for standard energy blocks, one held in the spring with a subsequent event scheduled for each fall. Under the 2025 Procurement Plan, the IPA will continue the use of two procurement events to be held in the spring and fall, as described below and in Section 7.1.

Coming into the Spring 2022 energy procurement event, slightly less than 50% of the hedging requirements for the 2022 summer months had been procured, leaving the balance to be procured in the Spring 2022 events. The IPA's Spring 2022 energy procurements were exposed to unprecedented market volatility and unexpected high prices resulting in higher costs for eligible retail customers than would have been incurred if the balance to be procured in the Spring event had been less. In response, for the 2023 Plan, the IPA increased the percentage of summer load to be hedged in early procurement events in such a way that the summer procurement volumes to be hedged in the spring prior to delivery are reduced by about half. This approach seeks to limit the exposure to the adverse price risks during the volatile summer months by reducing the hedging percent target for the prompt summer months in the Spring procurement events. This approach was continued for the 2024 Plan and is proposed for the 2025 Plan.

The tables below illustrate the cumulative targets for July and August on-peak by procurement event and reflect a phase-in of the procurement for Delivery Years 2025, 2026, 2027, 2028, and 2029. Targets to be used in the Spring and Fall 2025 procurement events are specified in Section 7.1.1 of this Plan.

Table 6-1: Proposed Cumulative Procurement Targets for Ameren Illinois and MidAmerican

Procurement Event	July and August on-peak for Calendar Year					
	2025	**2026**	**2027**	**2028**	**2029**	**2030**
Fall 2024*	50%	25%				
Spring 2025	106%	52.5%	15%			
Fall 2025		75%	30%			
Spring 2026		106%	52.5%	15%		
Fall 2026			75%	30%		
Spring 2027			106%	52.5%	15%	
Fall 2027				75%	30%	
Spring 2028				106%	52.5%	15%

* Approved targets in the 2024 Plan.

Table 6-2: Proposed Cumulative Procurement Targets for ComEd

Procurement Event	July and August on-peak for Calendar Year					
	2025	**2026**	**2027**	**2028**	**2029**	**2030**
Fall 2024*	50%	25%				
Spring 2025	50%	26.25%	15.00%			
Fall 2025		37.50%	30.00%			
Spring 2026		50%	52.50%	15.00%		
Fall 2026			75.00%	30.00%		
Spring 2027			106%	52.50%	15.00%	
Fall 2027				75.00%	30.00%	
Spring 2028				106%	52.5%	15.00%

* Approved targets in the 2024 Plan.

The targets in Table 6-2 reflect the scheduled end of CMC contracts and their associated offsetting value at the end of the 2026-2027 Delivery Year. For 2027 and subsequent years, the cumulative targets for ComEd would match the schedule for Ameren Illinois and MidAmerican. As discussed in Section 6.9.1, the Agency has adjusted ComEd hedging levels to reflect ComEd's feedback on the draft Plan to reduce the amount of eligible retail customer load hedged by IPA procured contracts to 30% for the October through May delivery months.

This procurement schedule balances procurement overhead costs, price risk, and load uncertainty. If the amounts to be hedged in any year are small, the Agency could decide to avoid the procurement overhead and not schedule a procurement event (as in 2013).

The Agency has not used options, unit specific contracts (except for the LTPPAs and the since-cancelled FutureGen agreements), or other forms of hedging in the past. In addition, the Agency has not used forward sales or put options to rebalance its portfolio.

6.6.2 Measuring the Cost and Uncertainty Impacts of Supply Risk Factors

The IPA's procurement and hedging strategy has been challenged by volatile market conditions which had a major impact on the prices and availability of the wholesale energy blocks procured during the Spring 2022 procurement events. To address the risks associated with volatility in forward energy prices, the IPA has periodically reviewed its approach to hedging and investigated the merits of alternative procurement strategies. The primary goal of these reviews has been to evaluate the potential for further minimizing the volatility and cost of the utilities' supply portfolios. An objective of the procurement strategy is to maximize stability of the resulting rates for service to eligible retail customers, while minimizing cost.

The cost to eligible ratepayers for service in a given month is driven by the average price paid for energy procured under an IPA procurement plan. The stability of that cost is a function of the long-term trends (both predictable and random) in forward prices over the procurement period, and the random level of forward prices experienced on the specific days in which components of the portfolio are procured.

The IPA conducted an analysis for the 2021 Plan related to procurement scheduling and volatility. That analysis was updated for the 2023 Plan, and was reviewed for the 2024 Plan and this 2025 Plan. The updated analysis examined the degree to which varying the number of scheduled annual procurement events and moving procurements closer to their delivery months affect volatility price risk for individual delivery months in the portfolio. Shortening the time interval between the Agency's procurement event and the initial delivery month, along with using multiple annual procurement events, can result in an improved portfolio with lower price volatility.

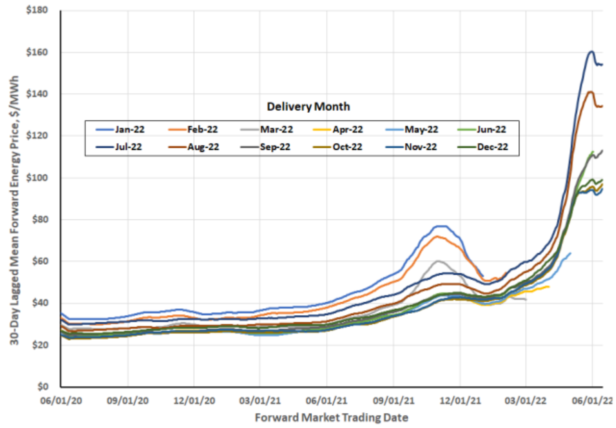
The results of the updated analysis indicated that the closer the procurement events are held to the product delivery date, the greater the price volatility on the hedges procured. Also, a review of monthly forward market volatilities does not support a preference for any periods of the year as ideal or to be avoided for conducting procurement events. However, to reduce uncertainty in procurement costs, the shape of the volatility-to-term curves indicate that procurements should be made several months in advance of the contract delivery dates to reduce price volatility. Other overriding factors, such as the risk of load switching associated with Municipal Aggregation programs, also impact the scheduling of procurement events relative to delivery timing and result in reasonable decisions to hold procurement events close to product delivery dates. The IPA's current hedging approach using a forward hedging strategy involving procurements over parts of three delivery years with two annual energy procurement events provides a means for reasonably mitigating price and volume risks associated with the procurement of energy supply blocks. The purchases of quantities up to three years prior to delivery have produced the lowest volatility of portfolio price.

6.7 Number and Timing of Procurement Events

The analysis considered two, three, and four procurement events per year, with each delivery month procured in the four or five events prior to delivery. With two events per year, the total procurement for a given year of delivery months would cover 2+ years, so 3 years (May 2018 to April 2020) of historical forwards were analyzed to get 12 delivery months (September 2019 to August 2020) of procurement costs. Prices for a given delivery month over the procurement period were reasonably stable month to month and showed low daily variation within any given month. Results showed very little impact on average price for different procurement schedules.

An updated analysis of historical Northern Illinois Hub forward on-peak energy prices was conducted to examine the impact of high prices and volatility. For the delivery months in 2022, the analysis shows that the volatility and price trends previously observed in 2017 through early 2020 continued into most of 2021. Figure 6-2 shows the daily forward prices for the 12 2022 delivery months for trading dates from June 2020 through early June 2022. Prices shown are 30-day lagged averages of daily prices reported by NYMEX.

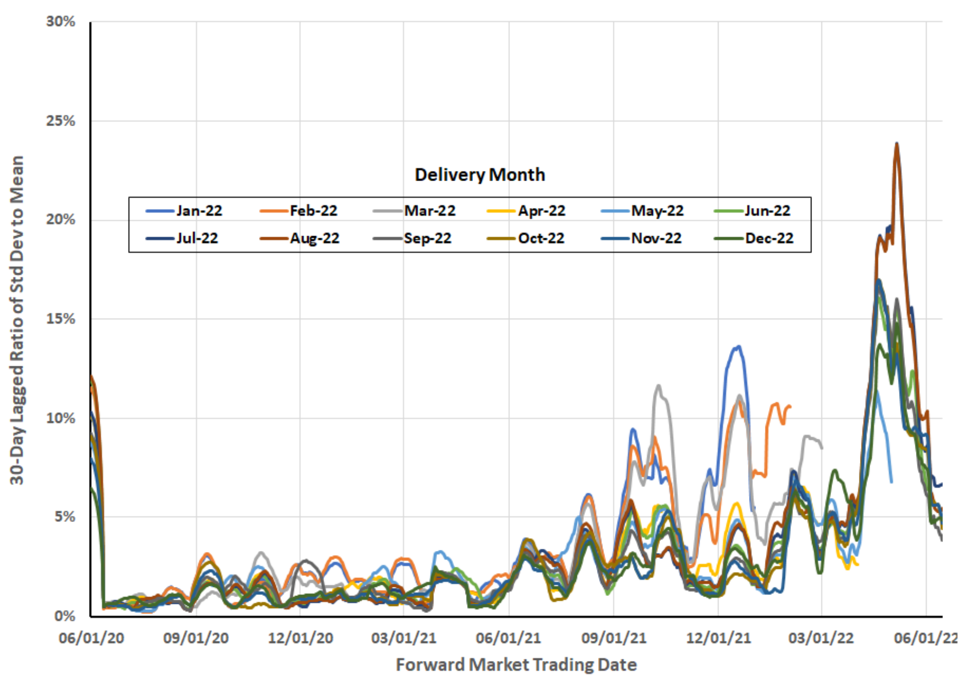
Figure 6-2: Northern Illinois Daily Forward Prices for 2022 Delivery Months



The prices appear to be stable through October 2021, when the winter month prices briefly spike. Prices subsequently dropped and leveled out until late-March of 2022, when they begin to rise sharply, particularly for the upcoming 2022 summer delivery months. Prices reached a peak at the end of May 2022 and dropped slightly afterward. The decline in prices continued through the end of 2022 and into 2023.

The standard deviation for the 30 days of prices represented by each point in the previous chart is shown in Figure 6-3. Variations are generally low as a percentage of mean for trading dates through late 2021, when variability spikes for the prompt winter delivery months. Volatility drops again until late March 2022 when it climbs dramatically through April, then peaks and falls significantly by early May.

Figure 6-3: Northern Illinois Daily Forward Prices for 2022 Delivery Months (Standard Deviation as % of Mean)



The analysis of the impact of these prices on the results of the April 2022 Procurement Event and the May 2022 Supplemental Event focused on the last few months of trading date data as applied to the summer 2022 delivery months. Figure 6-4 and Figure 6-5 show the same data as the previous charts for that more focused timeframe and identify the dates on which the two most recent procurement events occurred.

Figure 6-4: Northern Illinois Daily Forward Prices for April – December 2022 Delivery Months

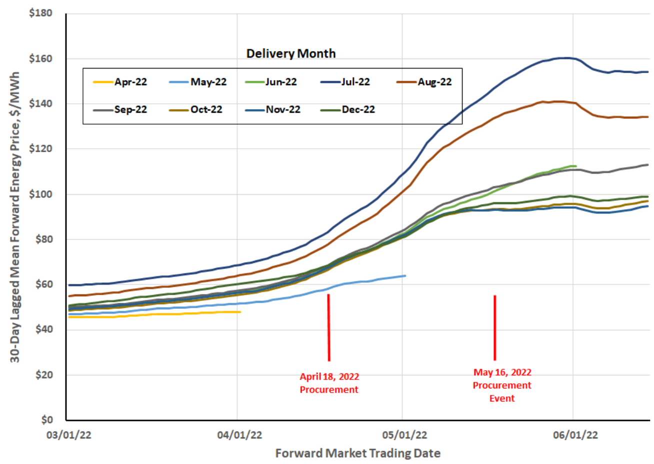
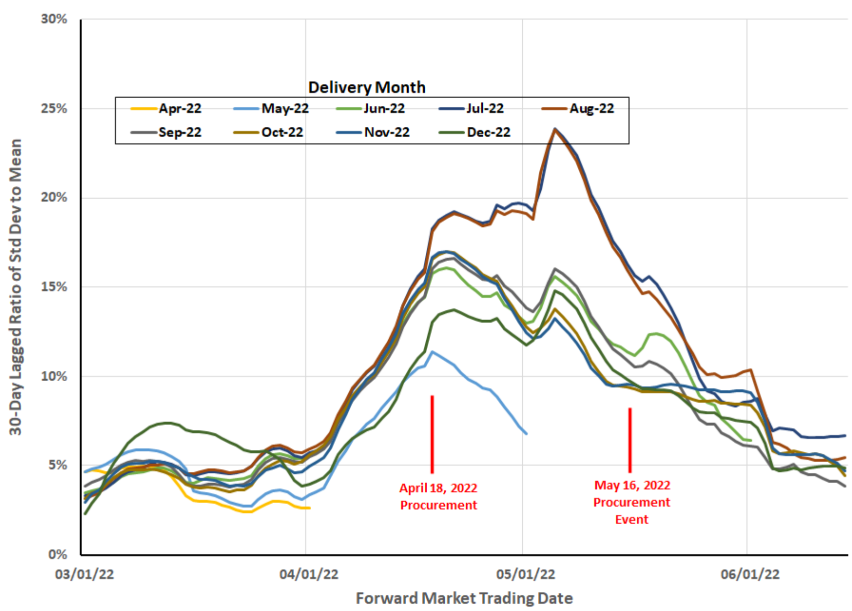


Figure 6-5: Northern Illinois Daily Forward Prices for April – December 2022 Delivery Months (Standard Deviation as % of Mean)



The forward prices, particularly for the upcoming July and August delivery months, were extremely volatile in the days leading up to and including the April 18, 2022 procurement event and were characterized by high prices. Undoubtedly, bidders were faced with high intra-day volatility, which created significantly more uncertainties than normally experienced with the bids they were submitting. These uncertainties are likely to have resulted in the incorporation of risk adders to the forward market price in the blocks that were offered. By the May 16, 2022 Supplemental Procurement Event, market prices were higher, but the 30-day standard deviation had decreased significantly.

6.7.1 Review of Proposed Changes to Hedge Volumes to be Procured in the Last Procurement Event Ahead of the upcoming June, July, and August

Figure 6-6 and Figure 6-7 show the means and standard deviations of total hedge energy procurement cost for each delivery month under the current hedge percentage schedule and the three alternative schedules used in the prior analysis. Each of the alternatives involves purchasing in 5 equal increments of 20% for each delivery month, with plans spread over 1+ to about 3 years. The costs are strictly the forward energy cost – no other adders. Note the standard deviation for the summer months on the "2020 Plan" which uses the current hedge percentage schedule are dramatically higher than those for other plans.

Figure 6-6: Hedge Portfolio Price Means

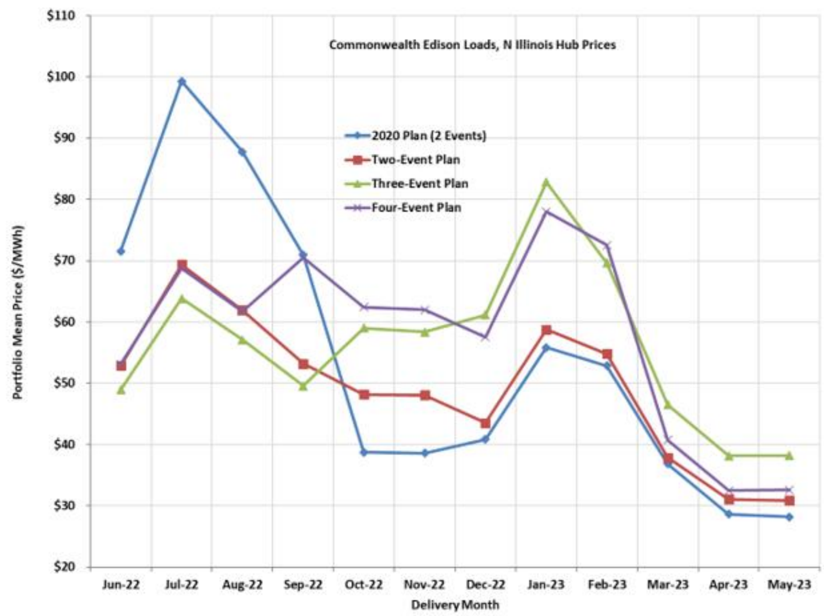
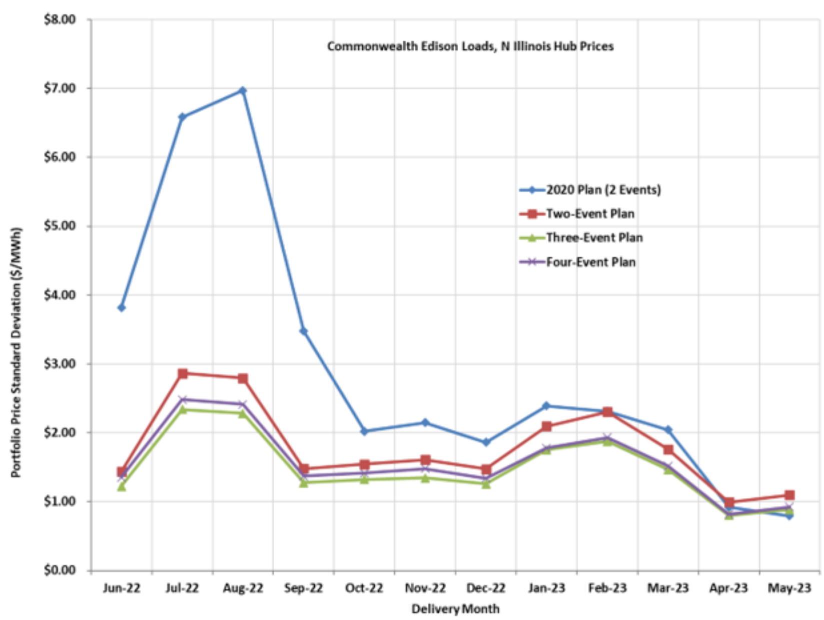


Figure 6-7: Hedge Portfolio Price Standard Deviation



The data here do not provide strong support for increasing the number of annual procurements events beyond the current Spring and Fall schedule.

However, these charts indicate that the current schedule for procuring the summer month blocks resulted in greater unexpected costs than would have been incurred if only 20% or 25% of the requirements for those months had been needed, rather than around 50%. As mentioned earlier, the increase in prices and higher volatility that occurred in April and May of 2022 was not anticipated and was inconsistent with forward price patterns from earlier years. The 2022 schedule of procurement targets for non-summer delivery months specify the procurement of up to 75% of the requirements in procurement events leading to the final procurement in the fall event, just prior to delivery. On the other hand, the 2022 schedule of procurement targets for summer delivery months specifies the procurement of up to 50% of the requirements in procurement events leading to the final procurement in the spring event, just prior to delivery. Summer months, July and August in particular, are generally among the highest priced and most volatile delivery months in forward and spot energy markets. Additionally, the volatility of forward prices tends to increase as time to delivery becomes shorter. This provides support for the IPA to implement a revised hedging strategy that would result in a portfolio of supply hedges with less uncertainty resulting from having about 75% of requirements in hand prior to the Spring procurement event just prior to delivery.

To avoid having particular short-term trends or events drive the conclusions, a statistical analysis focused on a model-based decomposition of the sources of seasonal and stochastic fluctuations was also conducted in a separate analysis using data for a representative time period prior to the impact of the 2022 energy price spikes. This approach, grounded in financial economic theory and quantitative methods, was used to assess key aspects of electric energy forward prices that continue to be important considerations for price hedging. MISO Illinois hub and PJM Northern Illinois hub on-peak and off-peak forwards prices were analyzed with a general model for use with forwards that have seasonally varying prices.[226] This modeling approach has three basic steps for characterizing price volatility of a particular forward product. The data sample analyzed spans monthly forwards from September 2015 through August 2020 and trade dates from August 3, 2015 through August 31, 2018.

First, for each trading date, the deseasonalized average of prices for the forward curve over 24 months is calculated for each trade date, starting with the prompt month. (Using data for 24 months ensures that the impact of seasonality is removed.) The daily fluctuations in 24-month average prices reflect market conditions apart from the predictable expected seasonal component of forward prices. In the model, logarithms of prices are used because commodity prices have uncertainty distributions that resemble a lognormal distribution more than a normal distribution. The deseasonalized log price series is modeled as a stochastic, or uncertain, variable that represents the historical trajectory of 24-month average forward prices over time.

Second, the seasonal premia by calendar month, expressed as percent of the deseasonalized prices, were calculated as the average difference between the daily prices for a product that expires (or physically delivers) in the specific calendar month and the daily deseasonalized prices.

The third and final factor in the decomposition of forward prices is what is known as the "convenience yield." The convenience yield is the residual of the forward price minus the deseasonalized forward price and the seasonal premium. The convenience yield is modeled as a second stochastic factor, which varies by time to maturity, accounting for the dynamics of supply-demand imbalances. The convenience yield volatility curves have smooth and rapidly decaying convenience yield volatility rates at more distant maturities. This shape is expected because more information about impending spot market conditions becomes known in the final months and days before the forward product's delivery period begins than is known many months in advance of delivery. The convenience yield volatilities of the off-peak product are slightly higher than the on-peak product at each hub, with the difference most pronounced in the prompt month.

Combining the deseasonalized forward price volatility factor and the convenience yield factor produces a term structure of average volatility. The curves for the PJM Northern Illinois and MISO Illinois hubs decline for the first several months due to the relatively high convenience yield, and then stay roughly constant, consistent with the assumption that forward prices do not exhibit mean reversion, which would be indicated by continued decline in volatility at more distant maturities. For the deseasonalized forward volatility curves, the volatility rate becomes roughly constant after month five to month eight. Figure 6-8 and Figure 6-9 depict the calculated term structure of average volatility applicable to ComEd and Ameren Illinois wholesale markets.

[226] S. Borovkova and H. Geman, "Seasonal and stochastic effects in commodity forward curves," *Review of Derivatives Research* (2006) pp. 167-186.

Figure 6-8: PJM Northern Illinois, Volatility Term Structure

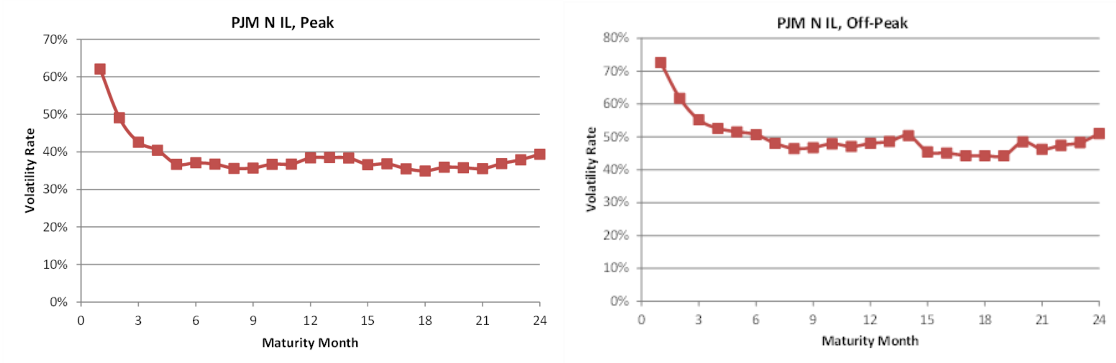
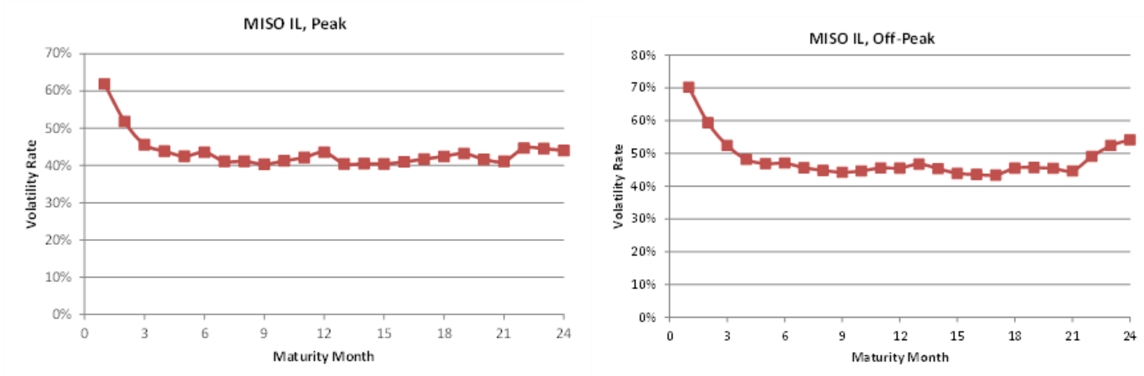


Figure 6-9: MISO Illinois, Volatility Term Structure



The stable volatility of average forward prices and the maturity-varying profile of convenience yields both lend support to a strategy of using multiple procurements which may be evenly spaced and sized. In order to avoid excessive uncertainty in procurement costs, the shape of the convenience yield curves indicates that the last procurement should be made several months in advance of contract expiration.

The conclusions based on these analyses remain relevant for this Plan. Taking into consideration the changes proposed for the summer month procurement targets, the IPA will continue to use the energy procurement schedule and implement a modification to the hedging approach utilized in the prior Plan. Following the Commission's Order approving the 2023 Electricity Procurement Plan, the Agency's hedging approach for the ComEd energy procurements includes consideration of the offsetting cost impact that Carbon Mitigation Credits can provide to eligible retail customers by leaving 50% of load unhedged through IPA procurements. The Agency continued this approach for the 2024 Plan and proposes to continue it for the 2025 Plan, with the modification of hedging to only 30% non-summer period (e.g., leaving 70% of the load unhedged). CMC contracts expire at the end of the 2026-2027 Delivery Year. Following the end of those contracts, the IPA plans that its hedging strategy and procurement targets will cover all of the energy supply requirements of ComEd's eligible retail customers, and that is reflected in the targets for the 2027-2028 Delivery Year.

6.8 Demand Response as a Risk Management Tool

Demand response programs operated by ComEd are not used to offset the incremental demand, over and above the weather-normalized base case peak load. The programs act as supply risk management tools to help assure that sufficient resources are available under extreme conditions. Under the current PJM capacity construct, demand resources participate fully as a source of supply in the capacity procurement process, and the RPM provides capacity compensation for demand resources that clear in RPM auctions in the same manner as cleared generation resources receive compensation. To participate fully as a source of supply, the demand response resource must, either by itself or, if seasonal, by being coupled with another eligible seasonal resource, be able to meet the annual availability requirements imposed on resources by PJM's adoption of Capacity Performance requirements.

In the case of Ameren Illinois and MidAmerican, MISO provides the ability for demand response measures to reduce supply risk. On March 14, 2014, FERC approved MISO's modification to its Module E-1 tariff to treat demand response and energy efficiency resources in a manner similar to other capacity providing resources for operational planning purposes. MISO distinguishes between capacity resources that clear the capacity auction and load modifying resources ("LMR") that have no capacity supply obligation. LMR have different obligations than capacity resources but do count toward planning resources. By qualifying as an LMR, the demand resource can help meet resource adequacy requirements obligations and receives compensation for providing planning resource capability. Also, by qualifying as an LMR, the demand resource is obligated to curtail during emergencies and may be penalized for failure to do so.[227] On February 2, 2017, FERC approved proposed changes to MISO's tariff to establish measurement and verification criteria for the LMR for the purpose of determining whether these resources are meeting their performance obligations.[228] On February 19, 2019, FERC approved revisions to MISO's tariff which allow MISO to more effectively access the capabilities of LMRs by requiring an LMR to offer its capability based on availability in all seasons and be deployed based on the shortest notification requirement that it can meet.[229] These rules will improve transparency around LMR capability by providing firmer and more clearly documented commitments regarding availability prior to participating in MISO's capacity market.

FERC Order No. 745 requires Independent System Operators and RTOs to compensate demand response resources participating in wholesale markets at the market price. In January 2016, the U.S. Supreme Court reversed a D.C. Circuit Court of Appeals ruling and upheld FERC's jurisdiction over demand response competing in wholesale markets, holding that the Federal Power Act provides FERC with the authority to regulate wholesale market operators' compensation of demand response bids and affirming the validity of the methodology used by FERC to provide compensation.[230] Chapter 7 of this Plan provides details and additional discussion regarding demand response resources.

6.9 Impact of Carbon Mitigation Credits on the Hedging Strategy for ComEd Eligible Retail Load

Carbon Mitigation Credits can help offset the impact of higher wholesale prices on retail customers in the ComEd service territory, including eligible retail customers, due to the indexing of the CMC price to the PJM busbar price. A key consideration for the determination of CMC payments is the legislated baseline CMC costs set at $30.30/MWh for the 2022-2023 Delivery Year, $32.50/MWh for the 2023-2024 Delivery Year, $33.43/MWh for the 2024-2025 Delivery Year, $33.50/MWh for the 2025-2026 delivery year, and $34.50/MWh for the 2026-2027 Delivery Year. The baseline costs set the limit for CMC price bids. All of the accepted CMC bids were priced at the baseline costs. The day-ahead market price for the relevant month and the value of capacity stated on a $/MWh basis are subtracted from the CMC bid price to determine the amount to be used in calculating the CMC payment. If the monthly CMC price calculation results in a net negative value, such as is likely to be the case during periods of high wholesale electricity prices, the CMC supplier makes payments that benefit all of ComEd's retail customers. As a result, payments from the CMC supplier would help offset the impact of higher wholesale prices on retail customers.

In the Commission proceeding approving the 2023 Plan, ComEd argued that the volume of CMCs purchased by ComEd could serve to provide offsetting price benefits for 60% to 65% of the eligible customer energy requirements in each month going forward. Under this approach, the IPA's block energy procurements would be implemented to hedge less than half of ComEd's eligible customer load, with the portion of the energy requirements not covered to be settled through purchases in the spot day-head market in the relevant delivery month (which would eventually be offset by ComEd's CMC purchases).

[227] A service that can include LMRs in MISO is Emergency Demand Response (EDR). EDR resources are required to respond during an emergency. EDR resources may qualify as LMR but are not required to do so. The EDR has flexibility with respect to offering emergency energy but is not counted as capacity towards resource adequacy requirements.

[228] See Midcontinent Independent System Operator, Inc., 158 FERC ¶ 61,119 (2017).

[229] See Midcontinent Independent System Operator, Inc., 166 FERC ¶ 61,116 (2019).

[230] See FERC v. Electric Power Supply Ass'n, 2016 WL 280888, 136 S. Ct. 760 (2016).

In its Final Order approving the 2023 Plan, the Commission conditionally accepted ComEd's proposal to reduce the hedging target in the ComEd service territory to 50%.[231] The Commission found that ComEd's hedging strategy would be a reasonable approach if revisions to Rider Carbon-Free Resource Adjustment "CFRA" (the CMC tariff) were first made allowing for more frequent adjustments "to reconcile any over- or under-collections under the CMC tariff on the same four-month lag that the PEA follows to reconcile purchased energy." The Commission explained that approval of such tariff revisions "would trigger the associated reduction in the hedging level to 50% if those revisions are approved by March 31, 2023."[232] ComEd accordingly filed the necessary tariff changes on December 21, 2022, the Commission voted not to suspend the filing on January 19, 2023, and the tariff changes became effective on February 4, 2023.[233] The updated reconciliation process was fully implemented by the October 2023 monthly billing period.

The Agency updated the 2023 Plan hedging target in the ComEd territory for all months to 50%. The hedging targets for ComEd updated in the previous Plan will be continued for this Plan through the 2026-2027 Delivery Year, with the adjustment of hedging non-summer months to 30%. The Commission explicitly noted in its Final Order that "[i]n the event of default on CMC contracts, the IPA may change the hedging percentages for ComEd to mirror those of Ameren and MidAmerican, with the consensus of the IPA, Staff, and the Procurement Monitor."[234]

In comments received on the draft Plan, ComEd proposed that "to maximize the CMC hedge during the non-summer months of October to May, when ComEd deliveries are the lowest, the percentage of open load should increase from 50% in the IPA's current 2025 Draft Plan to 70%."[235] This proposal was based on ComEd previous recommendations and ComEd's analysis of Section 6.9.1 below. Taking this adjustment into account yields a lower net cost when compared to the previous methodology of a 50% year-round hedge. The Agency has considered ComEd's proposal and agrees with it, and the Agency proposes to adjust hedging percentages accordingly.

6.9.1 Results of CMC Benefits Analysis – Relative Cost Impact

The ICC's Order approving the 2023 Plan called for a significant change to the IPA's energy hedging strategy for ComEd, leaving 50% of forecasted eligible retail load unhedged (e.g., an open position) to take advantage of the offsetting pricing benefits of CMCs.

The CMC price is calculated by taking the CMC Bid Price for the delivery year and subtracting, (1) the weighted monthly average busbar price for the participating nuclear units, and (2) the price of capacity for the delivery year.[236] The resulting price can be other positive or negative depending on wholesale electricity prices. ComEd's eligible retail customers thus benefit when negative prices result in payments made by the CMC suppliers, while when prices are positive the CMC suppliers receive payments.

The price of CMCs from June 2022 through May 2024 varied significantly. CMC prices were initially negative due to the price spike that occurred in 2022. This variance reflects falling energy prices after the summer of 2022 and relative price stability since the extreme price volatility seen through much of calendar year 2022. The CMC prices are shown in Table 6-3.

[231] See Final Order, ICC Docket No. 22-0590 at 23.

[232] Ibid

[233] See: https://www.icc.illinois.gov/meetings/meeting/commission-meeting/21512.

[234] See Final Order, ICC Docket No. 22-0590 at 24.

[235] See ComEd comments at: https://ipa.illinois.gov/content/dam/soi/en/web/ipa/documents/20240917-comed-comments.pdf .

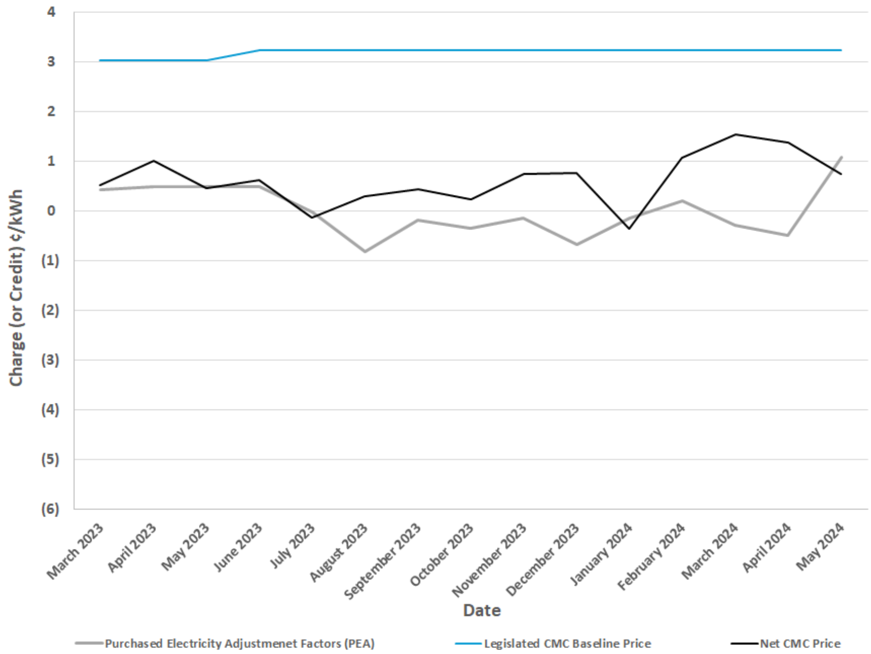
[236] CMC prices will also be adjusted to account for the value of any Federal subsidies. As of the release of this draft 2025 Electricity Procurement Plan, the IRS has not finalized the guidelines for a nuclear production tax credit. See Section 4.2 of the CMC Procurement Plan for more information of the process that would be utilized to introduce such an adjustment.

Table 6-3: Carbon Mitigation Credit Prices, June 2022 through June 2023

Month	CMC Price ($ / MWh)
Jun-22	-$52.30
Jul-22	-$52.79
Aug-22	-$60.11
Sep-22	-$42.21
Oct-22	-$18.35
Nov-22	-$16.05
Dec-22	-$33.36
Jan-23	-$4.24
Feb-23	$3.49
Mar-23	$5.28
Apr-23	$10.17
May-23	$4.62
Jun-23	$6.21
Jul-23	-$1.25
Aug-23	$3.09
Sep-23	$4.51
Oct-23	$2.39
Nov-23	$7.50
Dec-23	$7.76
Jan-24	-$3.63
Feb-24	$10.73
Mar-24	$15.54
Apr-24	$13.85
May-24	$7.43

Figure 6-10 below presents a monthly comparison of the Purchased Electricity Monthly Factors (PEA) versus both the Legislated CMC Baseline Price and the Net CMC Price. The Net CMC Prices are calculated by adjusting the CMC Baseline Costs for monthly energy and capacity credits. Prior to February 2023, CMC prices seen by customers did not change on a monthly basis, rather they were set based on an energy price forecast conducted by ComEd in the spring of 2022. Following a revision to Rider CFRA by ComEd, the CMC price seen by customers adjusts on a monthly basis. Initially, those adjustments included recalibrating the mismatch between the energy price forecast and actual market prices that reflected how energy prices fell in the second half of 2022. As shown in Figure 6-10, the summer of 2023, the CMC price and the PEA have generally moved in opposite directions, as was expected through this change.

Figure 6-10: Monthly Purchased Electricity Adjustment Factors vs. CMC Baseline and CMC Net Prices



For this Plan, the IPA conducted a review and analysis of the relative cost impact of taking advantage of the value of purchase of CMCs to provide offsetting benefits for a target volume of 50% of the utility's eligible retail load (with the remaining 50% of the load is still covered by IPA procured contracts) as compared with using IPA procured forward energy contracts to hedge 100% of the load. This analysis of monthly data focused on the time period for which the use of CMCs to provide offsetting benefits for ComEd's eligible load was implemented, June 2023 through May 2024. The results provide an indication of the relative benefits that ComEd's eligible retail customers could expect to receive when 50% of their load is left uncovered by (e.g., not covered by hedges procured by the IPA) in order to take advantage of the CMC contracts.[237]

The net cost analysis takes into consideration the cost of CMCs, the cost of the IPA's procured hedges, and the day ahead market price of electricity during a specific month to identify the relative value of leaving 50% of the customer supply uncovered by IPA procured hedges to take advantage of the off-setting benefits of CMCs which are paid for by ComEd's eligible customers in either case. The costs associated with IPA's forward contracts and CMCs are balanced against the credit for the market value of the forward contracts, with the net cost compared for each procurement/hedging approach. The lower net cost reflects the benefit to eligible retail customers.

Figure 6-11 shows the components of net cost for this by month for the period of June 2023 through May 2024, the total months for which CMCs hedging strategy has been implemented. The net cost takes into consideration the comparison of costs and/or benefits of CMCs to ComEd's eligible customers which depend on market prices as well as CMC prices, the cost of forward IPA procured contracts settled in that month, and the market value (credit) for those contracts based on market prices.

[237] Please see Appendix H for additional information on this analysis.

Figure 6-11: IPA Hedges 50% of Eligible Load

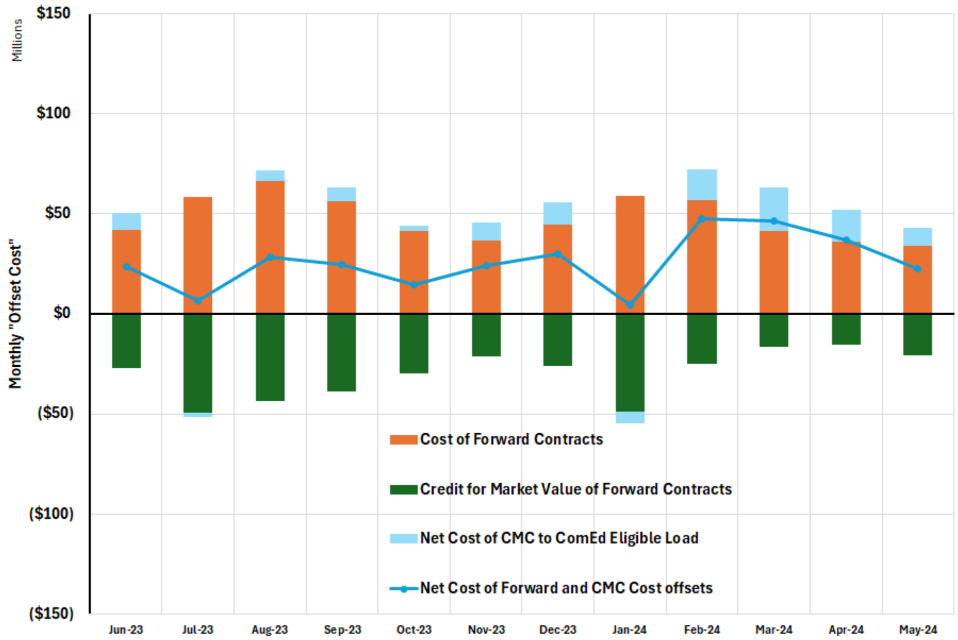
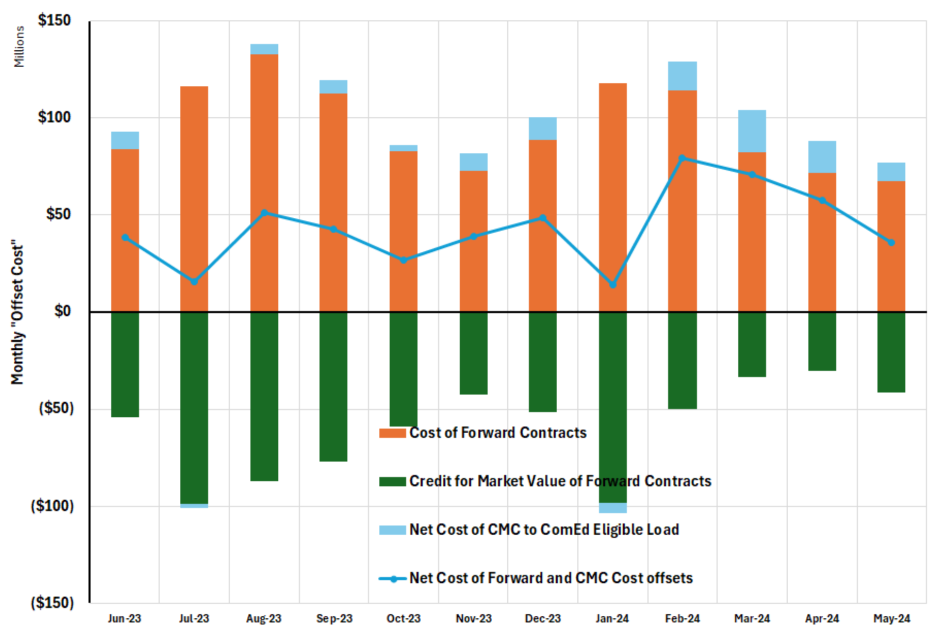


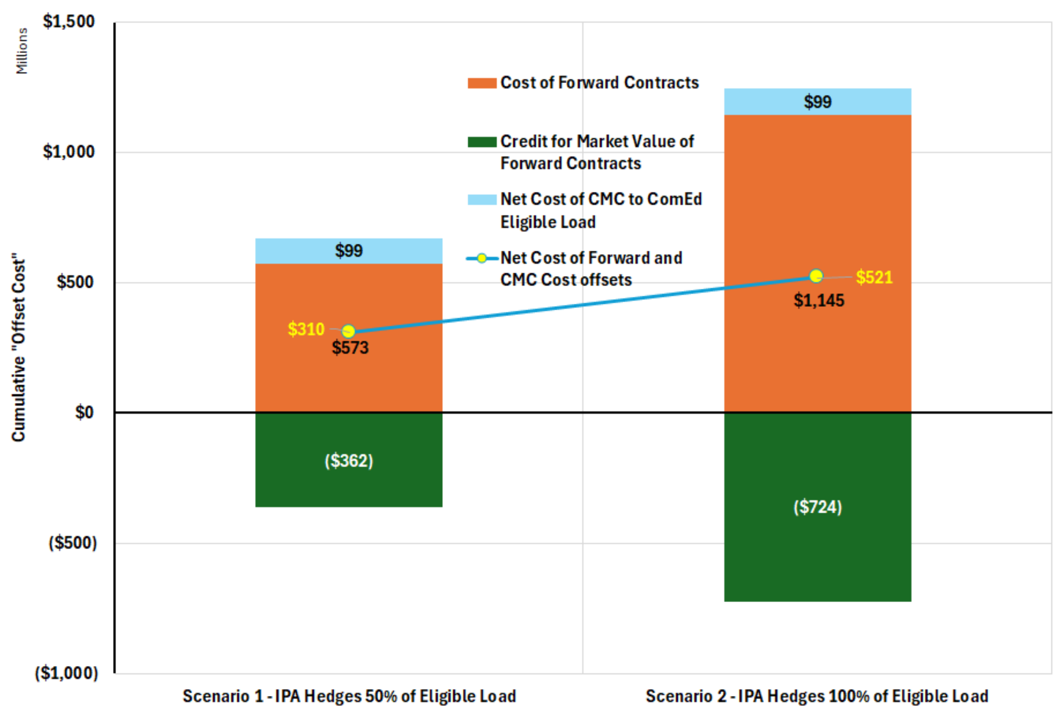
Figure 6-12 shows that if the amount of forward energy market hedging is doubled, as in the 100% hedging by IPA procured forward energy contracts, net costs increase in most months, partially offsetting the benefits of the CMCs.

Figure 6-12: IPA Hedges 100% of Eligible Load



In Figure 6-13 the net cost of $310 million for covering 50% of load with IPA procured hedges and 50% with CMC offsets as compared with the net cost of $521 million for 100% coverage of the load with IPA procured hedges results in $211 million in lower net cost (the benefits) to eligible retail customers for taking advantage of the CMC contract offsets. The primary element contributing to the cost differential is the net over-hedging that results from procuring forward energy contracts for 100% of the eligible retail load while at the same time the offsetting impact of CMCs is in effect. The relative net costs of these hedging strategies moving forward will depend on a variety of factors including the actual cost of forward energy contracts procured by the IPA and the wholesale price of electricity. While CMC contracts remain in effect through the end of the 2026-2027 Delivery Year, the lower costs in avoiding net over hedging (that is 100% IPA procured contracts plus the impact of CMC contracts) provide benefits to ComEd's eligible retail customers, however, when this program ends, the benefits vanish and using 100% IPA procured hedges once again becomes the most effective approach to protect eligible retail customers from electricity market price volatility.

Figure 6-13: Total Cost Impact (June 2023 Through May 2024)



On September 16, 2024, ComEd submitted comments to the IPA on the draft 2025 Electricity Procurement Plan. ComEd stated that to "maximize the CMC hedge during the non-summer months of October to May, when ComEd deliveries are the lowest, the percentage of open load should increase from 50% in the IPA's current 2025 Draft Plan to 70%."[238] Taking this adjustment into account yields a net cost of $251 million (compared to the $310 million and $521 million net costs as stated above). The IPA agrees with ComEd's comments and for the winter months (October through May) the IPA's proposes that the procurement for ComEd's eligible retail customers will leave 70% of their requirements uncovered so that the value CMCs can be utilized to the maximum extent possible.

This analysis shows that for the period considered (June 2023 through May 2024) and the market conditions that existed during that period, utilizing the price offsets created by CMC contract in combination with hedging only 50% of ComEd load lowered the costs to ComEd's eligible retail customers. Those costs are further lowered when hedging only 30% of ComEd load for the non-summer months. Therefore, the IPA has proposes incorporating the non-summer 30% hedging level to the hedging strategy for ComEd eligible retail customers for the 2025-2026 and 2026-2027 Delivery Years.

[238] See ComEd Comments at: https://ipa.illinois.gov/content/dam/soi/en/web/ipa/documents/20240917-comed-comments.pdf.

7 Resource Choices

This Chapter of the Procurement Plan sets out recommendations for the resources to be procured for the forecast horizon covered by this Plan. These include: (1) energy; (2) capacity; (3) transmission and ancillary services; (4) demand response; and (5) clean coal.

7.1 Energy

7.1.1 Energy Procurement Strategy

The IPA's energy hedging strategy for the 2025 Procurement Plan is consistent with the strategy used for the 2024 Plan.

- Procure hedges consisting of standard 25 MW energy blocks.
- Hedges will be calculated on the expected monthly average on-peak and off-peak load.
- Conduct two procurement events in 2025: one in the Spring, and one in the Fall.

This Plan continues the approach adopted in the 2023 Plan which recognizes the offsetting price impacts for ComEd's eligible retail customers created by ComEd's CMC contracts through the end of the 2026-2027 Delivery Year. Under this approach, as refined for this plan, the IPA only hedges 50% of ComEd's forecast eligible retail customer load in summer months and 30% of ComEd's forecast eligible retail customer load during non-summer months, with the price volatility of the remaining load offset by month to month changes in the CMC price.[239] As this Plan calls for the procurement of electricity through the 2027-2028 Delivery Year, this Plan includes a ramping up of procurement volumes in anticipation of returning to hedging 100% of ComEd's forecast eligible retail customer load starting in the 2027-2028 Delivery Year.

For Ameren Illinois and MidAmerican, at the conclusion of the Spring procurement event, the target cumulative hedges in each utility's supply portfolio should be as follows:

- For the period of June through September of the 2025-2026 Delivery Year, the target cumulative hedges should be approximately 100% of each monthly average on-peak and off-peak load, except for July and August on-peak, which should be 106%. For the period of October through May of the prompt Delivery Year, the target cumulative hedges in the portfolio should be approximately 75% of each monthly on-peak and off-peak average load.
- For the 2026-2027 Delivery Year the target cumulative hedges in the portfolio should be approximately 37.5% of each monthly on-peak and off-peak average load, except for June, July and August on-peak and off-peak, which should be approximately 52.5%.
- For the 2027-2028 Delivery Year the target cumulative hedges in the portfolio should be approximately 12.5% of each monthly on-peak and off-peak average load, except for June, July and August on-peak and off-peak, which should be approximately 15%.

For Ameren Illinois and MidAmerican, at the conclusion of the Fall procurement event, the resulting target cumulative hedges in each utility's supply portfolio should be as follows:

- For the 2025-2026 Delivery Year the target cumulative hedges in the portfolio should be approximately 100% of the average monthly on-peak and off-peak load, except for July and August peak, which should have been hedged at 106% in the Spring procurement.
- For the 2026-2027 Delivery Year the target cumulative hedges in the portfolio should be approximately 50% of the average monthly on-peak and off-peak load, except for June, July and August on-peak and off-peak, which should be approximately 75%.
- For the 2027-2028 Delivery Year the target cumulative hedges in the portfolio should be approximately 25% of the average monthly on-peak and off-peak load, except for June, July and August on-peak and off-peak, which should be approximately 30%.

For ComEd, at the conclusion of the Spring procurement event, the target cumulative hedges in each utility's supply portfolio should be as follows:

- For the period of June through September of the 2025-2026 Delivery Year, the target cumulative hedges should be approximately 50% of each monthly average on-peak and off-peak load. For the

[239] See Section 6.9 of this Plan for more information.

period of October through May of the prompt Delivery Year, the target cumulative hedges in the portfolio should be approximately 37.5% of each monthly on-peak and off-peak average load.
- For the 2026-2027 Delivery Year the target cumulative hedges in the portfolio should be approximately 18.75% of each monthly on-peak and off-peak average load, except for June, July and August on-peak and off-peak, which should be approximately 26.25%.
- For the 2027-2028 Delivery Year the target cumulative hedges in the portfolio should be approximately 12.5% of each monthly on-peak and off-peak average load, except for June, July and August on-peak and off-peak, which should be approximately 15%.

For ComEd at the conclusion of the Fall procurement event, the resulting target cumulative hedges in each utility's supply portfolio should be as follows:
- For the 2025-2026 Delivery Year the target cumulative hedges in the portfolio should be approximately 50% of the average monthly on-peak and off-peak load.
- For the 2026-2027 Delivery Year the target cumulative hedges in the portfolio should be approximately 25.0% of the average monthly on-peak and off-peak load, except for June, July and August on-peak and off-peak, which should be approximately 37.5%.
- For the 2027-2028 Delivery Year the target cumulative hedges in the portfolio should be approximately 25% of the average monthly on-peak and off-peak load, except for June, July and August on-peak and off-peak, which should be approximately 30%.

The strategy is summarized in Tables 7-1 and 7-2.

Table 7-1: Summary of Energy Procurement Strategy for Ameren Illinois and MidAmerican[240]

Spring 2025 Procurement			**Fall 2025 Procurement**		
June 2025-May 2026 (Upcoming Delivery Year)	**Upcoming Delivery Year+1**	**Upcoming Delivery Year+2**	**October 2025-May 2026**	**Upcoming Delivery Year + 1**	**Upcoming Delivery Year + 2**
June 100% on-peak and off-peak July and Aug. 106% on-peak, 100% off-peak Sep. 100% on-peak and off-peak Oct. – May 75% on-peak and off-peak	37.5% all months, except June, July and August on-peak and off-peak, which should be 52.5%.	12.5% all months, except June, July and August on-peak and off-peak, which should be 15%.	100% all months	50% all months, except June, July and August on-peak and off-peak, which should be 75%.	25% all months, all months, except June, July and August on-peak and off-peak, which should be 30%.

[240] Table shows the cumulative percentage of load targeted to be hedged by the conclusion of the indicated procurement events.

Table 7-2: Summary of Energy Procurement for ComEd[241]

Spring 2025 Procurement			Fall 2025 Procurement		
June 2025-May 2026 (Upcoming Delivery Year)	Upcoming Delivery Year+1	Upcoming Delivery Year+2	October 2025-May 2026	Upcoming Delivery Year + 1	Upcoming Delivery Year + 2
June - Sep. 50% on-peak and off-peak, Oct. - May 22.5% on-peak and off-peak	11.5% all months, except June, July, August, and September on-peak and off-peak, which should be 26.25%.	12.5% all months except June, July August, and September on-peak and off-peak which should be 15%.	30% all months	15.0% all months, except June, July August, and September on-peak and off-peak, which should be 37.5%.	25% all months except June, July August, and September on-peak and off-peak which should be 30%.

7.1.2 Energy Procurement Implementation

The following tables and figures were constructed using each utility's July 2024 base load forecasts to provide indicative procurement values for the 2025-2026 Delivery Year.[242] The actual target procurement volumes used for the Spring and Fall 2025 procurements will be calculated using the March 2025 and the July 2025 updated load forecasts respectively. The IPA recommends that each utility submit forecast updates that reflect the most accurate and up-to-date information and modeling available at the time. In updating the load forecasts, the utilities may incorporate refinements to their forecasts including but not limited to changes to variables' values (such as switching) and reasonable enhancements to econometric models, provided that any such refinements are properly disclosed and subject to the review and consensus of the IPA, ICC Staff, the Procurement Monitor, and the applicable utility.

While the utilities provided five years of load forecasts, given the absence of visible and liquid block energy markets four and five years out, it is not recommended that any block energy purchases be made to secure supply for those years (Delivery Years 2028-2029 and 2029-2030) in this Procurement Plan. Therefore, the tables and figures that follow only cover Delivery Years 2025-2026, 2026-2027, and 2027-2028.

[241] Table shows the cumulative percentage of load targeted to be hedged by the conclusion of the indicated procurement events.

[242] The anticipated procurement volumes are rounded up or down to the nearest 25 MW block. For additional information on expected load and supply already under contract, see Appendices E (Ameren Illinois), F (ComEd), and G (MidAmerican).

Figure 7-1: Ameren Illinois Peak Energy Supply Portfolio and Load

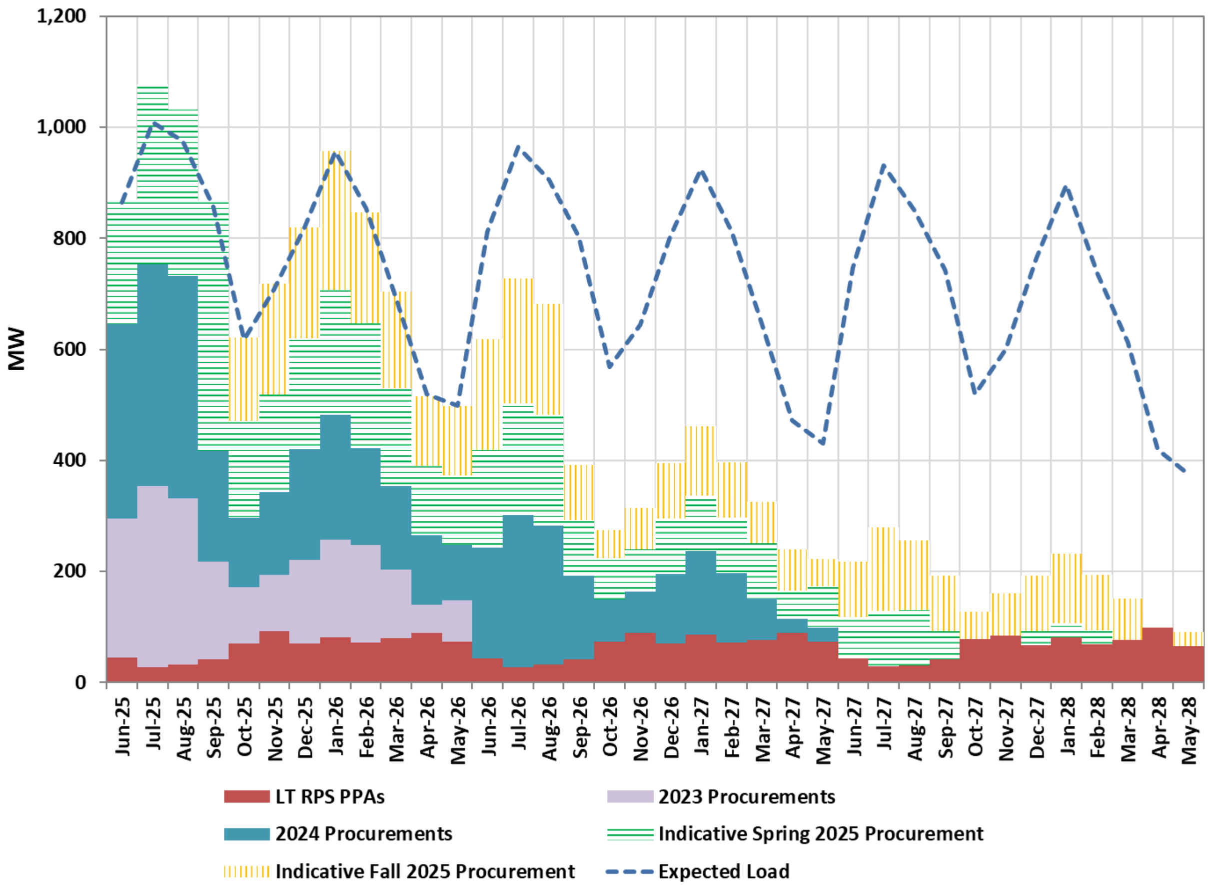


Figure 7-2: Ameren Illinois Off-Peak Energy Supply Portfolio and Load

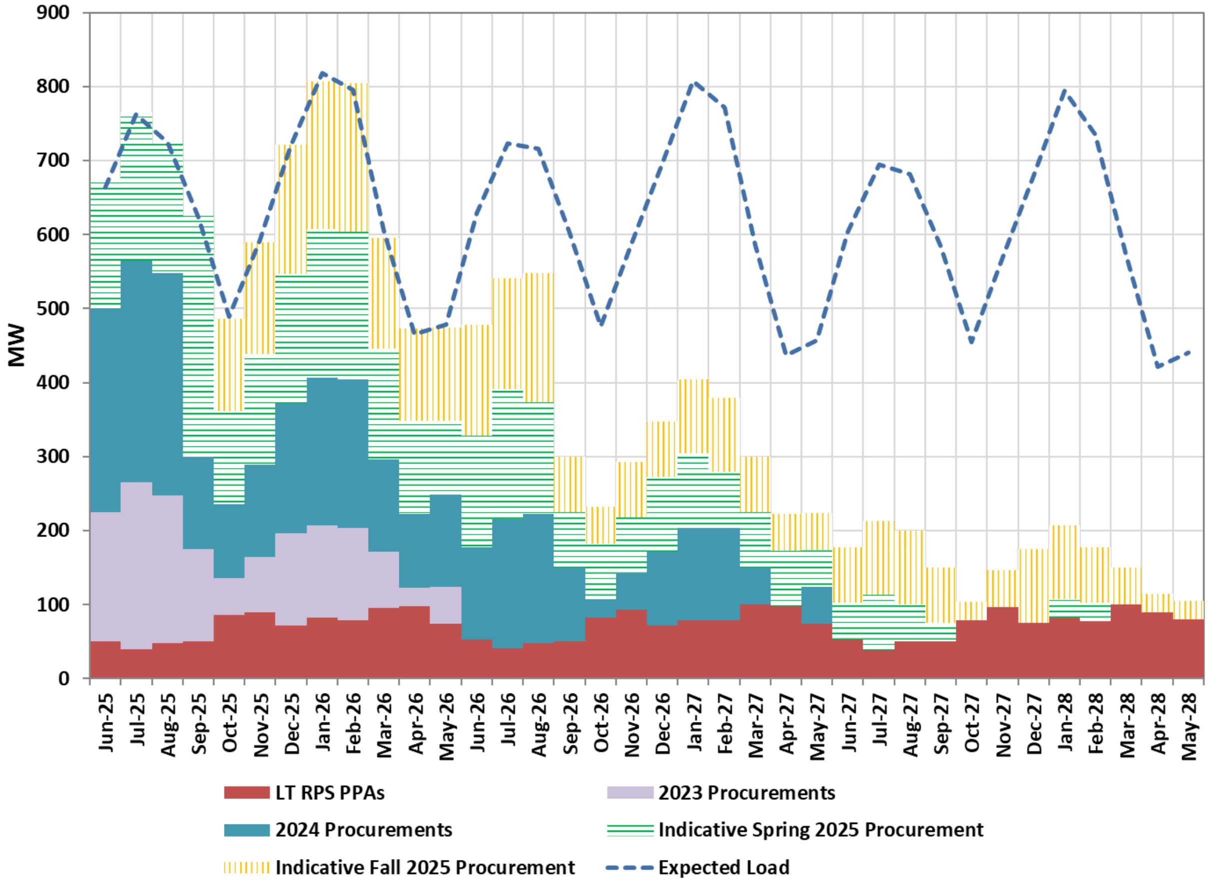


Table 7-3: Ameren Illinois 2025 Spring and Fall Procurements

Delivery Month	Anticipated Spring 2025 Purchases (MW)		Anticipated Fall 2025 Purchases (MW)	
	Peak	Off-Peak	Peak	Off-Peak
Delivery Year 2025-2026				
Jun-25	225	175	0	0
Jul-25	325	200	0	0
Aug-25	300	175	0	0
Sep-25	450	325	0	0
Oct-25	175	125	150	125
Nov-25	175	150	200	150
Dec-25	200	175	200	175
Jan-26	225	200	250	200
Feb-26	225	200	200	200
Mar-26	175	150	175	150
Apr-26	125	125	125	125
May-26	125	100	125	125
Delivery Year 2026-2027				
Jun-26	175	150	200	150
Jul-26	200	175	225	150
Aug-26	200	150	200	175
Sep-26	100	75	100	75
Oct-26	75	75	50	50
Nov-26	75	75	75	75
Dec-26	100	100	100	75
Jan-27	100	100	125	100
Feb-27	100	75	100	100
Mar-27	100	75	75	75
Apr-27	50	75	75	50
May-27	75	50	50	50
Delivery Year 2027-2028				
Jun-27	75	50	100	75
Jul-27	100	75	150	100
Aug-27	100	50	125	100
Sep-27	50	25	100	75
Oct-27	0	0	50	25
Nov-27	0	0	75	50
Dec-27	25	0	100	100
Jan-28	25	25	125	100
Feb-28	25	25	100	75
Mar-28	0	0	75	50
Apr-28	0	0	0	25
May-28	0	0	25	25

Figure 7-3: ComEd Peak Energy Supply Portfolio and Load

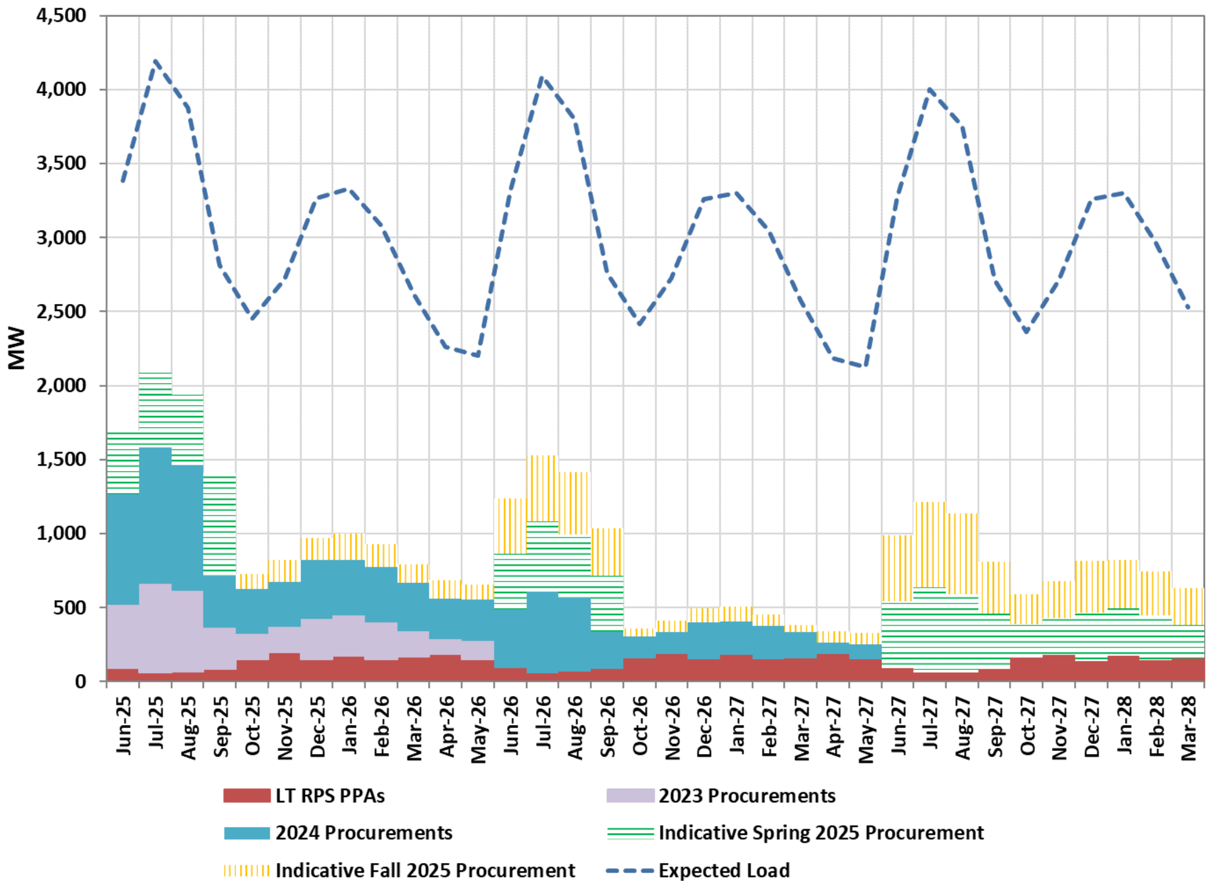


Figure 7-4: ComEd Off-Peak Energy Supply Portfolio and Load

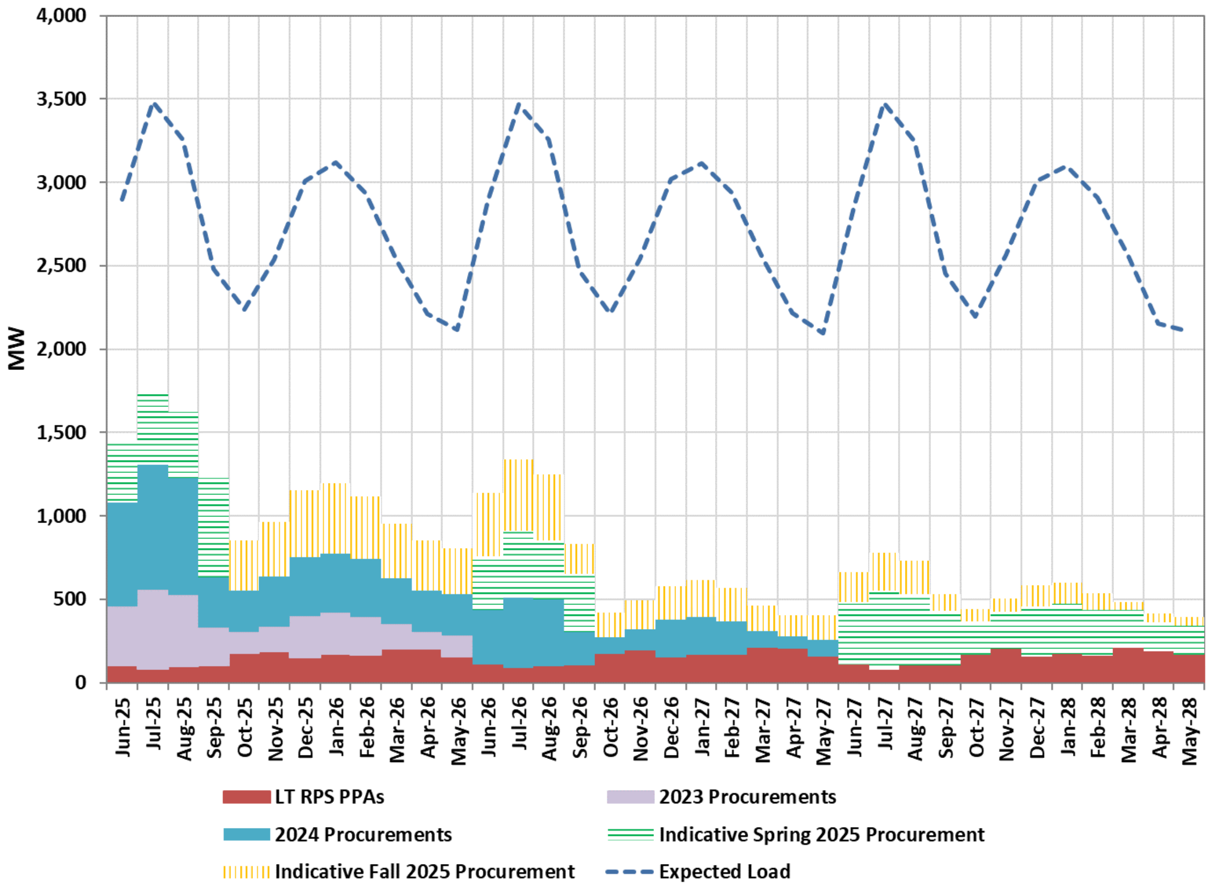
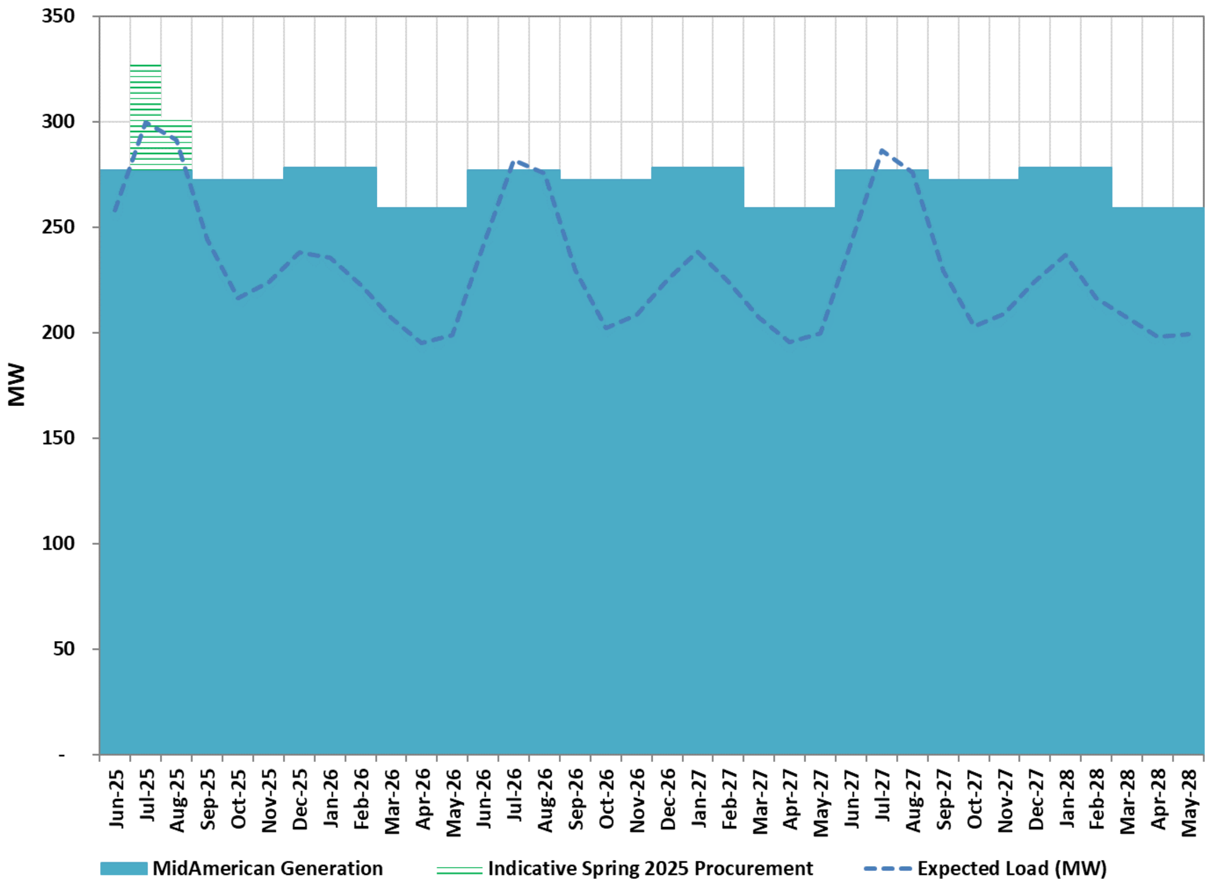


Table 7-4: ComEd 2025 Spring and Fall Procurements

Delivery Month	Anticipated Spring 2025 Purchases (MW)		Anticipated Fall 2025 Purchases (MW)	
	Peak	Off-Peak	Peak	Off-Peak
Delivery Year 2025-2026				
Jun-25	425	375	0	0
Jul-25	500	425	0	0
Aug-25	475	400	0	0
Sep-25	700	600	0	0
Oct-25	0	0	100	125
Nov-25	0	0	150	125
Dec-25	0	0	150	150
Jan-26	0	0	175	175
Feb-26	0	0	150	150
Mar-26	0	0	125	125
Apr-26	0	0	125	100
May-26	0	0	100	100
Delivery Year 2026-2027				
Jun-26	375	325	375	325
Jul-26	475	400	450	400
Aug-26	425	350	425	375
Sep-26	375	350	325	275
Oct-26	0	0	50	50
Nov-26	0	0	75	50
Dec-26	0	0	100	75
Jan-27	0	0	100	75
Feb-27	0	0	75	75
Mar-27	0	0	50	75
Apr-27	0	0	75	50
May-27	0	0	75	50
Delivery Year 2027-2028				
Jun-27	450	375	450	375
Jul-27	575	475	575	500
Aug-27	525	425	550	450
Sep-27	375	325	350	300
Oct-27	225	200	200	175
Nov-27	250	225	250	225
Dec-27	325	300	350	300
Jan-28	325	300	325	300
Feb-28	300	275	300	300
Mar-28	225	225	250	200
Apr-28	175	175	150	175
May-28	200	175	175	175

Figure 7-5: MidAmerican Peak Energy Supply Portfolio and Load[243]



[243] While it may appear that the volume of hedges to be procured for MidAmerican is relatively small, it is important to recognize that the incremental cost of acquiring these hedges is also relatively small and that the hedges cover a period of significant price volatility in the electric power markets - peak summer.

Figure 7-6: MidAmerican Off-Peak Energy Supply Portfolio and Load

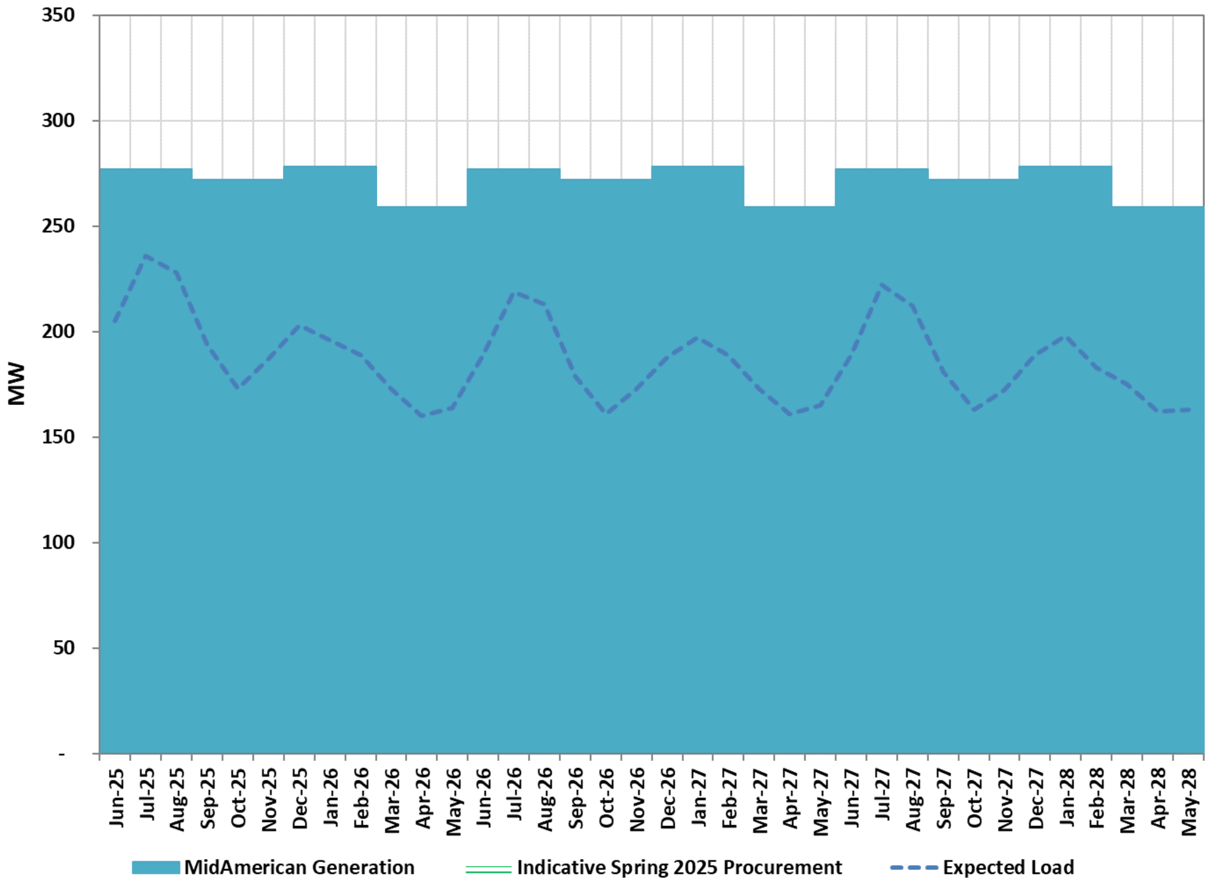


Table 7-5: MidAmerican 2025 Spring and Fall Procurements

Delivery Month	Anticipated Spring 2025 Purchases (MW)		Anticipated Fall 2025 Purchases (MW)	
	Peak	Off-Peak	Peak	Off-Peak
Delivery Year 2025-2026				
Jun-25	0	0	0	0
Jul-25	50	0	0	0
Aug-25	25	0	0	0
Sep-25	0	0	0	0
Oct-25	0	0	0	0
Nov-25	0	0	0	0
Dec-25	0	0	0	0
Jan-26	0	0	0	0
Feb-26	0	0	0	0
Mar-26	0	0	0	0
Apr-26	0	0	0	0
May-26	0	0	0	0
Delivery Year 2026-2027				
Jun-26	0	0	0	0
Jul-26	0	0	0	0
Aug-26	0	0	0	0
Sep-26	0	0	0	0
Oct-26	0	0	0	0
Nov-26	0	0	0	0
Dec-26	0	0	0	0
Jan-27	0	0	0	0
Feb-27	0	0	0	0
Mar-27	0	0	0	0
Apr-27	0	0	0	0
May-27	0	0	0	0
Delivery Year 2027-2028				
Jun-27	0	0	0	0
Jul-27	0	0	0	0
Aug-27	0	0	0	0
Sep-27	0	0	0	0
Oct-27	0	0	0	0
Nov-27	0	0	0	0
Dec-27	0	0	0	0
Jan-28	0	0	0	0
Feb-28	0	0	0	0
Mar-28	0	0	0	0
Apr-28	0	0	0	0
May-28	0	0	0	0

7.2 Capacity

7.2.1 Capacity Procurement Strategy

7.2.1.1 ComEd

Prior procurement plans, including the 2024 Procurement Plan, have recommended that ComEd obtain its capacity needs through the PJM-administered capacity market. For this 2025 Plan, the IPA proposes that ComEd continue to obtain its capacity needs from the PJM-administered capacity market. Table 7-8 summarizes the proposed capacity procurement for ComEd.

7.2.1.2 Ameren Illinois

For Ameren Illinois, the 2024 Procurement Plan recommended a procurement of a portion of the Ameren Illinois capacity needs for the 2024-2025, 2025-2026, and 2026-2027 Delivery Years through bilateral capacity purchases obtained through the IPA competitive procurement process, with the remainder of its capacity needs procured through the MISO PRA. The IPA will continue this capacity procurement strategy which involves the procurement of 75% of the capacity requirements (in the form of ZRCs and financial capacity swaps ("Financial ZRCs") in the near-term forward markets through IPA administered RFPs in a laddered fashion, and the remaining balance through the MISO PRA. Additionally, as discussed in Section 5.2.2.1 and elsewhere in this Plan, in line with the MISO Tariff and the move to a Seasonal Resource Adequacy Construct, the IPA has adjusted its bilateral procurement approach. The IPA no longer procures annual ZRCs and instead conducts bilateral procurements for each of the four seasons and procuring seasonal ZRCs. For this 2025 Plan, the Agency will use a consistent hedging level across all four seasons. Also, for this Plan, in addition to seasonal capacity, the IPA proposes to include the procurement of annual planning year capacity products, both physical ZRCs and financial capacity swaps (Financial ZRCs). As future year results of MISO seasonal capacity auctions become available, the Agency will analyze the results of those auctions and may propose changes in seasonal hedging levels in future plans.

As also discussed in Section 5.2.2.7, the 2025 Plan does not change the 75%/25% procurement strategy which was approved in the 2024 Plan. The strategy uses the same level of hedging for each of the four seasons (i.e., the 75% is equally applied to all four seasons in the IPA's procurements).

Specifically, for Ameren Illinois, the IPA proposes to use the following capacity procurement strategy:

- Conduct two procurement events in 2025, one in Spring, and one in Fall.
- Add a new option for bidders to bid on an annual combination product (e.g., a bid for a quantity of ZRCs for all four seasons that would be accepted in totality, rather than separate bids for each season) in addition to bidding on each season individually.
- Add a new option for taking bids on a financial swap product ("Financial ZRCs"). As described in Section 5.2.2.6, this product would not require the actual delivery of ZRCs to Ameren, rather the product would be a financially settled product where the price paid under the contract is settled against the resulting applicable seasonal MISO PRA price.
- Bids for ZRCs and the financial swap product ("Financial ZRCs") will be evaluated together, including both seasonal and annual bids. The Procurement Administrator will determine the least cost package of bids that are below the applicable benchmark and within the procurement target for approval by the Commission.
- For the 2025-2026 Delivery Year, no change to the procurement target from what was approved in the 2024 Procurement Plan. That is, to procure up to 75% of the forecasted capacity requirements through an RFP administered by the IPA in Fall 2024 and procure the remaining balance through the MISO PRA scheduled for April of 2025.
- For the 2026-2027 and 2027-2028 Delivery Years, the IPA will procure capacity requirements through its two 2025 capacity procurement events, resulting in hedging at the following levels:
    - At the conclusion of the Spring 2025 procurement event, the target cumulative capacity hedges in Ameren Illinois portfolio of Zonal Resource Credits ("ZRCs") or financial swap products ("Financial ZRCs") should be as follows:

    - For the 2026-2027 Delivery Year, the target cumulative hedges should be no more than 50% of the capacity requirements.
    - For the 2027-2028 Delivery Year, the target cumulative hedges should be no more than 12.5% of the capacity requirements.
  - At the conclusion of the Fall 2025 procurement event, the target cumulative capacity hedges in Ameren Illinois portfolio of Zonal Resource Credits ("ZRCs") or financial swap products ("Financial ZRCs") should be as follows:
    - For the 2026-2027 Delivery Year, the target cumulative hedges should be no more than 75% of the capacity requirements.
    - For the 2027-2028 Delivery Year, the target cumulative hedges should be no more than 25% of the capacity requirements.
- Procure the remaining balance of the 2026-2027 Delivery Year capacity requirements through the MISO PRA scheduled for April of 2026. No additional procurements of capacity for the 2024-2025 Delivery Year will be needed.
- Procure the remaining balance of the 2027-2028 Delivery Year capacity requirements in the MISO PRA and/or additional procurement events to be determined in the 2026 Procurement Plan.

While Ameren Illinois provided a five-year capacity requirement forecast, given the absence of visible and liquid capacity markets in MISO, it is not recommended that any capacity hedges be procured for years beyond the 2027-2028 Delivery Year in this Procurement Plan.

7.2.1.3 MidAmerican

The IPA notes that the magnitude of the proposed capacity procurements for MidAmerican is small relative to its capacity requirements, as shown in Table 7-6 which presents MidAmerican's load and capability. Consistent with the discussion regarding the procurement strategy for ComEd, MidAmerican will procure 100% of its forecasted capacity deficit through its RTO's capacity market, the MISO PRA.

Table 7-6: Summary of MidAmerican Load and Capability

Delivery Year	Non-Coincident Peak Load	Coincident Peak Load	Reserves	Coincident Peak Load with Reserves	Total Net Capability	Deficit to be Procured in MISO PRA
Summer						
2024-2025	442.7	428.3	38.5	466.9	392.4	74.5
2025-2026	422.6	408.9	36.8	445.7	392.3	53.4
2026-2027	404.2	391.1	35.2	426.3	392.3	34.0
2027-2028	404.7	391.6	35.2	426.8	392.3	34.5
2028-2029	405.2	392.1	35.3	427.4	392.3	35.1
2029-2030	405.8	392.6	35.3	427.9	392.3	35.6
Fall						
Delivery Year	**Non-Coincident Peak Load**	**Coincident Peak Load**	**Reserves**	**Coincident Peak Load with Reserves**	**Total Net Capability**	**Deficit to be Procured in MISO PRA**
2024-2025	381.8	360.2	51.1	411.3	389.2	22.1
2025-2026	364.0	343.4	48.8	392.2	387.8	4.4
2026-2027	347.7	328.0	46.6	374.6	387.8	-13.2
2027-2028	348.2	328.5	46.6	375.1	387.8	-12.7
2028-2029	348.6	328.9	46.7	375.7	387.8	-12.1
2029-2030	349.1	329.4	46.8	376.2	387.8	-11.6
Winter						
Delivery Year	**Non-Coincident Peak Load**	**Coincident Peak Load**	**Reserves**	**Coincident Peak Load with Reserves**	**Total Net Capability**	**Deficit to be Procured in MISO PRA**
2024-2025	308.5	297.8	81.6	379.4	375.8	3.6
2025-2026	290.7	280.6	76.9	357.5	372.7	-15.2
2026-2027	287.5	277.5	76.0	353.5	372.7	-19.2
2027-2028	288.0	277.9	76.2	354.1	372.7	-18.6
2028-2029	288.4	278.4	76.3	354.7	372.7	-18.0
2029-2030	288.9	278.8	76.4	355.2	372.7	-17.5
Spring						
Delivery Year	**Non-Coincident Peak Load**	**Coincident Peak Load**	**Reserves**	**Coincident Peak Load with Reserves**	**Total Net Capability**	**Deficit to be Procured in MISO PRA**
2024-2025	303.2	286.2	76.4	362.6	381.9	-19.3
2025-2026	286.3	270.3	72.2	342.5	380.5	-38.0
2026-2027	286.8	270.7	72.3	343.0	380.5	-37.5
2027-2028	287.2	271.1	72.4	343.5	380.5	-37.0
2028-2029	287.6	271.5	72.5	344.0	380.5	-36.5
2029-2030	288.0	271.9	72.6	344.5	380.5	-36.0

7.2.2 Capacity Procurement Implementation

7.2.2.1 Ameren Illinois

For Ameren Illinois, the IPA concludes that it does not need to include any extraordinary measures in the 2025 Procurement Plan to assure reliability over the planning horizon. In this Plan the Agency proposes that for the 2025-2026 Delivery Year, the IPA will not implement changes from the previously approved strategy. For the 2026-2027 and 2027-2028 Delivery Years, the IPA will continue the strategy of procuring Ameren Illinois capacity requirements through IPA-administered procurements and through the MISO PRA, as shown below in Table 7-7.[244]

[244] In Table 7-7, references to ZRCs include consideration of financial capacity swap product volumes.

Table 7-7: Summary of Capacity Procurement for Ameren Illinois

Delivery Year	Season	Requirement	Spring 2023 RFP	Fall 2023 RFP	Spring 2024 RFP	Fall 2024 RFP	April 2025 PRA	Additional Procurements
June 2025 - May 2026	Summer	1,824	0 ZRCs Procured	0 ZRCs Procured	0 ZRCs Procured	257 ZRCs Procured	Balance of Requirements, 1,567 ZRCs Estimated	0 ZRCs
	Fall	1,695	Quantity not Disclosed[245]	0 ZRCs Procured	0 ZRCs Procured	105 ZRCs Procured	Balance of Requirements, 1,540 ZRCs Estimated	0 ZRCs
	Winter	1,802	0 ZRCs Procured	0 ZRCs Procured	0	0 ZRCs Procured	Balance of Requirements, 1,802 ZRCs Estimated	0 ZRCs
	Spring	1,396	0 ZRCs Procured	4 ZRCs Procured	Quantity not Disclosed[246]	0 ZRCs Procured	Balance of Requirements, 1,367 ZRCs Estimated	0 ZRCs
Delivery Year	**Season**	**Requirement**	**Spring 2024 RFP**	**Fall 2024 RFP**	**Spring 2025 RFP**	**Fall 2025 RFP**	**April 2026 PRA**	**Additional Procurements**
June 2026 - May 2027	Summer	1,773	0 ZRCs Procured	293 ZRCs Procured	593 ZRCs/ Financial ZRCs Targeted for Procurement	443 ZRCs/ Financial ZRCs Targeted for Procurement	Balance of Requirements 443 ZRCs Estimated	0 ZRCs
	Fall	1,750	0 ZRCs Procured	32 ZRCs Procured	843 ZRCs/ Financial ZRCs Targeted for Procurement	438 ZRCs/ Financial ZRCs Targeted for Procurement	Balance of Requirements 438 ZRCs Estimated	0 ZRCs
	Winter	1,791	0 ZRCs Procured	0 ZRCs Procured	896 ZRCs/ Financial ZRCs Targeted for Procurement	448 ZRCs/ Financial ZRCs Targeted for Procurement	Balance of Requirements 448 ZRCs Estimated	0 ZRCs
	Spring	1,408	0 ZRCs Procured	3 ZRCs Procured	701 ZRCs/ Financial ZRCs Targeted for Procurement	352 ZRCs/ Financial ZRCs Targeted for Procurement	Balance of Requirements 352 ZRCs Estimated	0 ZRCs
Delivery Year	**Season**	**Requirement**	**Spring 2025 RFP**	**Fall 2025 RFP**	**Additional Procurements**			
June 2027 - May 2028	Summer	1,708	213 ZRCs/ Financial ZRCs Targeted for Procurement	213 ZRCs/ Financial ZRCs Targeted for Procurement	To be determined in 2026 Plan			
	Fall	1,720	215 ZRCs/ Financial ZRCs Targeted for Procurement	215 ZRCs/ Financial ZRCs Targeted for Procurement				
	Winter	1,788	223 ZRCs/ Financial ZRCs Targeted for Procurement	223 ZRCs/ Financial ZRCs Targeted for Procurement				
	Spring	1,411	176 ZRCs/ Financial ZRCs Targeted for Procurement	176 ZRCs/ Financial ZRCs Targeted for Procurement				

[245] In accordance with previous Commission orders, the quantity information is not released when the number of successful bidders is fewer than three.

[246] In accordance with previous Commission orders, the quantity information is not released when the number of successful bidders is fewer than three.

7.2.2.2 ComEd

For ComEd, the IPA concludes that it does not need to include any extraordinary measures in the 2025 Procurement Plan to assure reliability over the planning horizon. For this Plan the Agency proposes that ComEd will continue to meet all of its capacity obligations through the PJM-administered capacity market in which capacity is purchased in a three-year ahead forward market through mandatory capacity rules.

Table 7-8: Summary of Capacity Procurement for ComEd

June 2025-May 2026	June 2026-May 2027	June 2027-2028	June 2028-2029
100% PJM RPM Auctions*	100% PJM RPM Auctions**	100% PJM RPM Auctions***	100% PJM RPM Auctions****

*The 2025-2026 auction was be held in June 2024.

** The 2026-2027 auction will be held in December 2024.

*** The 2027-2028 auction will be held in June 2025.

**** The 2028-2029 auction will be held in December 2025

7.2.2.3 MidAmerican

For MidAmerican, the IPA concludes that it does not need to include any extraordinary measures in the 2025 Procurement Plan to assure reliability over the planning horizon. MidAmerican will continue to procure 100% of its capacity deficit for the 2025-2026, 2026-2027, and 2027-2028 Delivery Years through the MISO PRAs as indicated below.

Table 7-9: Summary of Capacity Procurement for MidAmerican

June 2025-May 2026 (Upcoming Delivery Year)	June 2026-May 2027	June 2027-May 2028
100% of capacity deficit through MISO PRA*	100% of capacity deficit through MISO PRA**	100% of capacity deficit through MISO PRA***

* MISO Auction for 2025-2026 is expected to clear in April 2025.
**MISO Auction for 2026-2027 is expected to clear in April 2026.
*** MISO Auction for 2026-2027 is expected to clear in April 2027.

7.3 Transmission and Ancillary Services

Ameren Illinois, MidAmerican, and ComEd purchase their transmission and ancillary services (which included energy balancing) from their respective RTOs, Ameren Illinois and MidAmerican from MISO and ComEd from PJM. The utilities also manage their Financial Transmission Rights (FTR) and Auction Revenue Rights (ARR) processes in their respective RTOs, consistent with ICC orders in prior Plans. The IPA is not aware of any justification or reason to alter these practices and therefore recommends they remain unchanged.

7.4 Demand Response Products

Section 8-103(c) of the PUA establishes a goal to implement demand response measures:

> *Electric utilities shall implement cost-effective demand response measures to reduce peak demand by 0.1% over the prior year for eligible retail customers, as defined in Section 16-111.5 of this Act, and for customers that elect hourly service from the utility pursuant to Section 16-107 of this Act, provided those customers have not been declared competitive. This requirement commences June 1, 2008 and continues for 10 years.*[247]

[247] 220 ILCS 5/8-103(c).

Section 8-103B(g)(4.5) of the PUA contains a similar requirement, requiring that Ameren Illinois and ComEd, "in submitting proposed plans and funding levels" to meet the state's new energy efficiency portfolio standard targets adopted through Public Act 99-0906, "implement cost-effective demand-response measures to reduce peak demand by 0.1% over the prior year for eligible retail customers, as defined in Section 16-111.5 of this Act, and for customers that elect hourly service from the utility pursuant to Section 16-107 of this Act, provided those customers have not been declared competitive."[248] This updated requirement now "continues until December 31, 2026."[249]

ComEd provided information[250] regarding its existing demand response programs for 2022-2023 which include:

- Direct Load Control ("DLC"): ComEd's residential central air conditioning cycling program is a DLC program with 62,446 customers with a load reduction potential of 63 MW.
- Voluntary Load Reduction ("VLR") Program: VLR is an energy-based demand response program, providing compensation based on the value of energy as determined by the real-time hourly market run by PJM. This program also provides for transmission and distribution ("T&D") compensation based on the local conditions of the T&D network. This portion of the portfolio has 965 MW of potential load reduction.
- Hourly Pricing (formerly known as Residential Real-Time Pricing (RRTP) Program): All of ComEd's residential customers have an option to elect an hourly, wholesale market-based rate. The program uses ComEd's Rate BESH to determine the monthly electricity bills for each RRTP participant. This program has 36,780 customers and a load reduction potential of 0.48 MW.
- Peak Time Savings (PTS) Program: This program offered pursuant to Section 16-108.6(g) of the PUA and was approved by the ICC in Docket No. 12-0484. The PTS program is an opt-in, market-based demand response program for customers with smart meters. Under the program, customers receive bill credits for kWh usage reduction during curtailment periods. The program commenced in 2015 with 56,000 customers and has grown to more than 330,368 customers in 2024. ComEd sold 155 MW of capacity for the 2024-2025 Delivery Year, with 96 MW of summer only capacity for the 2024-2025 Delivery Year. The capacity sold for the 2025-2026 Delivery Year has yet to be determined.

Ameren Illinois has implemented a Voltage Optimization Program (including, for example, Conservation Voltage Reduction ("CVR") Program). Ameren Illinois also offers a Real Time Pricing ("RTP") option and the additional associated Power Smart Pricing ("PSP") program for smaller customers. Pursuant to the Commission's Interim Order in Docket No. 13-0105, Ameren Illinois offers a Peak Time Rewards program (Rider PTR). According to Ameren Illinois, the program currently has approximately 129,000 customers and Ameren Illinois sold 13.2 MW of related capacity in the MISO PRA for the 2024-2025 Delivery Year, which provides the pool of funds used for customer rebates. This tariff pertains to an optional program available to DS-1 customers as of June 1, 2016, whereby a customer would receive a billing credit if they curtail electric energy use during specific peak usage periods.

MidAmerican administers a program called "SummerSaver Program," a residential Direct Load Control (DLC) program. At the time of gross system peak, the SummerSaver program was not in effect. In addition, there is a potential for load displacement due to curtailment of customers on an interruptible rate. There was no curtailment event in effect at the time of gross system peak.

The IPA will not procure any demand response from eligible retail customers in the 2025-2026 Delivery Year. Under current market and regulatory conditions, the IPA believes that a new demand response procurement by the IPA could not meet the standards set forth in Section 16-111.5(b)(3) of the Public Utilities Act. Reasons for this include, for example, the statutory requirement that demand response under this provision must come from "eligible retail customers," and as the IPA is not aware of any simple, straightforward way of definitively determining whether a non-competitive class customers take supply from the utility or an alternative retail electric supplier for purposes of any demand response aggregation, there may simply be no feasible way to ensure that only eligible retail customers participate. This challenge significantly reduces the likelihood that any demand response procurement would be "cost-effective." Further, there could be challenges in "satisfy[ing]

[248] 220 ILCS 5/8-103B(g)(4.5).

[249] Id.

[250] See Appendix C.

the demand-response requirements of the regional transmission organization market in which the utility's service territory is located," and "provid[ing] for customers' participation in the stream of benefits produced by the demand-response products." Fortunately for customers (including both eligible retail customers and those who have switched suppliers or take hourly priced service), the Peak Time Rewards (or Savings) programs as offered by Ameren Illinois and ComEd create value through reduction in capacity charges and the technologies utilized for capacity reductions also have the potential to provide longer term demand response capability that could operate over more peak hours than those used for calculations of capacity obligations.

Going forward, the IPA will continue to assess the demand response market and continue its involvement in stakeholder discussions regarding Illinois state policy on demand response. As the market changes and legal and regulatory barriers are addressed, the Agency may choose to propose a demand response procurement in a future procurement plan.

7.5 Clean Coal

The IPA Act contains an aspirational goal that cost-effective clean coal resources will account for 25% of the electricity used in Illinois by January 1, 2025.[251] As a part of the goal, the IPA's Procurement Plans are to also include electricity generated from clean coal facilities.[252] While there is a broader definition of "clean coal facility" contained in the definition section of the IPA Act,[253] Section 1-75(d) describes two special cases: the "initial clean coal facility"[254] and "electricity generated by power plants that were previously owned by Illinois utilities and that have been or will be converted into clean coal facilities"[255] ("retrofit clean coal facility"). Each of these special cases includes specific processes through which sourcing agreements for the power from the facilities would be entered into by both utilities and ARES. Currently, the IPA is unaware of any facility meeting the definition of either an "initial clean coal facility" or a "retrofit clean coal facility" that has announced plans to begin operations within the next five years.

In comments on the Draft 2019 Plan, the Agency received a proposal by two commenters seeking for the Plan to include a competitive procurement for sourcing agreements from a "clean coal facility"[256] (i.e., a facility that meets the definition of a "clean coal facility" under Section 1-10 of the IPA Act, but not the definition of "initial clean coal facility" or a "retrofit clean coal facility"). As the Agency understands it, these commenters were seeking a procurement to support the development of a small "clean coal" plant in Mattoon at the location of the original FutureGen project.

As a threshold matter, it is unclear what authority was granted to the Agency to procure sourcing agreements from a "clean coal facility" that does not meet either of the above-referenced special definitions. A similar proposal to procure sourcing agreements from a "clean coal facility" not meeting these special definitions through a competitive procurement process was made in connection with the IPA's 2015 Plan; after reviewing the arguments of all parties, the Commission articulated serious concerns with whether such a procurement was consistent with the IPA Act, concluding that it was "not convinced" that a proposal of this type "was contemplated by the Illinois General Assembly or is in the public interest."[257] Given the scant guidance and authority offered by the IPA Act for such a procurement process, that conclusion appears well-justified.

Other statutory and budgeting barriers also apply to the procurement of sourcing agreements from a "clean coal facility" that do not apply to the special cases mentioned above. Given the absence of any mechanism in the IPA Act to require ARES to purchase or pay for the output of such a facility, the facility's additional costs would only be borne by eligible retail customers. At present, eligible retail customer load is less than 25% of the total retail customer load in Illinois (and could vary significantly in future years with customer switching), thus leading to limited (and volatile) funding under the rate impact cap contained in Section 1-75(d)(2). Given

[251] 20 ILCS 3855/1-75(d).

[252] 20 ILCS 3855/1-75(d)(1).

[253] 20 ILCS 3855/1-10.

[254] Id.

[255] 20 ILCS 3855/1-75(d)(5).

[256] See Comments on the Draft 2019 Procurement Plan from Mattoon Power Enterprises LLC and Coles Together, available at https://ipa.illinois.gov/content/dam/soi/en/web/ipa/documents/2019procurementplan/mpe-procurement-comment.pdf and https://ipa.illinois.gov/content/dam/soi/en/web/ipa/documents/2019procurementplan/coles-together-comments-to-ipa-on-2019-draft-procurement-plan.pdf.

[257] Docket No. 14-0588, Final Order dated December 17. 2014 at 315.

cost estimates typically presented for proposed "clean coal" plants, it appears highly unlikely that a clean coal facility could be developed within statutory funding limitations.

The IPA is concerned that should it propose a "competitive" procurement event for clean coal facilities, all reasonable market information indicates that there would be very few or no viable bidders. As the competitive procurement model relies on robust participation that captures the value created by competition, such a process would have difficulty yielding least-cost results.

For these reasons, the Agency is not including a dedicated clean coal procurement in this Plan. To be clear, nothing in this analysis is intended to prohibit any "clean coal" facility from participating in the IPA's proposed block energy or capacity procurements described elsewhere in this Chapter; it is merely concluding that special treatment through a dedicated procurement event for long-term, source-specific "clean coal facility" sourcing agreements is not presently warranted by Section 1-75(d) of the Act. Currently, as far as the Agency can determine, development activities for the Mattoon "clean coal" plant have ceased.

The Agency will continue to monitor developments in federal carbon capture and sequestration legislation and policies in the event that these developments would have an impact on the development of clean coal projects in Illinois. To date, the Agency has not identified any carbon capture and sequestration projects, proposed or in development, that would qualify as "clean coal" facilities to be located in Illinois.[258]

[258] U.S. Department of Energy Clean Coal News. https://ww.energy.gov/fecm/listings/clean-coal-news. Accessed July 24, 2023.

8 Procurement Process Design

The procedural requirements for the procurement process are detailed in Section 16-111.5 of the Illinois Public Utilities Act ("PUA").[259] The IPA retains a Procurement Administrator that conducts competitive procurement events on behalf of the IPA. The costs of the Procurement Administrator that the IPA incurs are recovered from the bidders and suppliers that participate in the Agency's competitive solicitations, through both IPA-assessed Bid Participation Fees and Supplier Fees. The eligible retail customers for each of the participating utilities ultimately incur these costs as it is assumed that suppliers' bid prices reflect a recovery of these fees. The IPA and the Procurement Administrator review the procurement process each year to operate in the best interests of consumers and identify potential improvements, as required by the PUA.[260] The Agency implemented changes to the procurement process in response to the COVID-19 pandemic involving remote submission of bid documentation that have proven successful and reflect good practice; those will be continued going forward.

Under requirements enacted through P.A. 102-0662, starting with the IPA's 2022 procurements, bidders must comply with the Displaced Energy Workers Bill of Rights, as defined in the Energy Community Reinvestment Act. Section 10-25(b) of the Energy Community Reinvestment Act outlines the responsibilities that Illinois power plant operators, involved in the deactivation or closure of fossil fuel or nuclear power plants, have for the workers displaced by the deactivation or closure of these plants.[261] The Agency will not procure any wholesale energy products from bidders that fail to comply with these requirements.

Consistent with changes to the IPA's procurement process resulting from Public Act 99-0906, the IPA no longer includes the procurement of renewable energy resources as part of its annual Electricity Procurement Plan. The procurement of renewable energy credits ("RECs") is instead covered by the Agency's Long-Term Renewable Resources Procurement Plan.[262] The IPA's procurement process going forward will continue to procure standard wholesale products for the utilities' eligible retail customers through the annual procurement plans.

Section 16-111.5(e) of the Public Utilities Act specifies that the procurement process must include the following components:

(1) Solicitation, pre-qualification, and registration of bidders.

The procurement administrator shall disseminate information to potential bidders to promote a procurement event, notify potential bidders that the procurement administrator may enter into a post-bid price negotiation with bidders that meet the applicable benchmarks,[263] provide supply requirements, and otherwise explain the competitive procurement process. In addition to such other publication as the procurement administrator determines is appropriate, this information shall be posted on the Illinois Power Agency's and the Commission's websites. The procurement administrator shall also administer the prequalification process, including evaluation of credit

[259] See generally 220 ILCS 5/16-111.5.

[260] In 2020 in response to changes in workplace procedures due to the ongoing COVID-19 pandemic, the Procurement Administrator implemented changes to the proposal submission process to accept digitally signed inserts to the Part 1 Form certifications instead of the previously required notarized signatures.

[261] 20 ILCS 735/10-25(b).

[262] The IPA's Initial Long-Term Plan was approved by the Commission on April 3, 2018 through Docket No. 17-0838. A Revised Long-Term Plan was approved by the Commission in Docket No. 19-0995 on February 18, 2020, and subsequently modified upon reopening as approved by the Commission on May 27, 2021. While a Draft Second Revised Long-Term Plan was published concurrent with the Draft 2022 Procurement Plan, it was subsequently withdrawn in accordance with the enactment of P.A. 102-0662. A revised Long-Term Plan was released for public comment on January 13, 2022, in accordance with the recently enacted changes to Section 1-75(c)(1)(A) of the IPA Act. The Long-Term Plan was then filed with the ICC for approval on March 21, 2022, and approved by the ICC on July 14, 2022. The 2022 Long-Term Plan covered planned procurements and program activity for the 2022-23 and 2023-24 program years. A draft of the 2024 Long-Term Plan, which covers the 2024-25 and 2025-26 program years, was released for public comment on August 15, 2023. Following the public comment period, the revised 2024 Long-Term Plan was filed with the Commission for approval on October 20, 2023. The Commission approved the 2024 Long-Term Plan with the Final Order issued in Docket No. 23-0714 on February 20, 2024 and the final 2024 Long-Term Plan was published on April 19, 2024.

[263] The IPA Act requires the procurement administrator to notify bidders that the procurement administrator may, in its discretion, enter into post-bid price negotiations with bidders. In order to encourage best and final bids from the bidders and taking into consideration the mandated use of confidential benchmarks, the procurement administrators in previous procurements have decided not to engage in post-bid negotiations.

worthiness, compliance with procurement rules, and agreement to the standard form contract developed pursuant to paragraph (2) of this subsection (e). The procurement administrator shall then identify and register bidders to participate in the procurement event.

(2) Standard contract forms and credit terms and instruments.

The procurement administrator, in consultation with the utilities, the Commission, and other interested parties and subject to Commission oversight, shall develop and provide standard contract forms for the supplier contracts that meet generally accepted industry practices. Standard credit terms and instruments that meet generally accepted industry practices shall be similarly developed. The procurement administrator shall make available to the Commission all written comments it receives on the contract forms, credit terms, or instruments. If the procurement administrator cannot reach agreement with the applicable electric utility as to the contract terms and conditions, the procurement administrator must notify the Commission of any disputed terms and the Commission shall resolve the dispute. The terms of the contracts shall not be subject to negotiation by winning bidders, and the bidders must agree to the terms of the contract in advance so that winning bids are selected solely on the basis of price.

(3) Establishment of a market-based price benchmark.

As part of the development of the procurement process, the procurement administrator, in consultation with the Commission staff, Agency staff, and the procurement monitor, shall establish benchmarks for evaluating the final prices in the contracts for each of the products that will be procured through the procurement process. The benchmarks shall be based on price data for similar products for the same delivery period and same delivery hub, or other delivery hubs after adjusting for that difference. The price benchmarks may also be adjusted to take into account differences between the information reflected in the underlying data sources and the specific products and procurement process being used to procure power for the Illinois utilities. The benchmarks shall be confidential but shall be provided to, and will be subject to Commission review and approval, prior to a procurement event.

(4) Request for proposals competitive procurement process.

The procurement administrator shall design and issue a request for proposals to supply electricity in accordance with each utility's procurement plan, as approved by the Commission. The request for proposals shall set forth a procedure for sealed, binding commitment bidding with pay-as-bid settlement, and provision for selection of bids on the basis of price.

(5) A plan for implementing contingencies

[i]n the event of supplier default or failure of the procurement process to fully meet the expected load requirements due to insufficient supplier participation, commission rejection of results, or any other cause.

8.1 Contract Forms

The IPA believes that the standard wholesale energy product contract forms used in its procurements have now become largely standardized and should remain acceptable to future potential bidders. As was the case with the procurement events held from 2014 through 2024, the process to receive comments from potential bidders can be restricted to substantial changes to the forms (including contract forms, credit terms and instruments, and RFP documents), thus reducing Procurement Administrator time and billable hours, while shortening the critical path time needed to conduct a procurement event. This is because, prior to the 2014 procurement events, the forms, terms, and instruments had become relatively stable, with fewer comments being received from potential bidders requesting revision or optional terms for each succeeding procurement event. Procurement events conducted under the 2025 Procurement Plan will be the nineteenth iteration of IPA-run procurement events. In each iteration prior to 2014, potential bidders had an opportunity to comment on documents and those comments have been, where appropriate, incorporated into the documents or provided as acceptable alternative language. For the procurement events held from 2014 through 2024, potential bidders submitted only limited comments on the proposed changes to the forms.

An amendment to the Ameren Capacity Agreement was included for the Spring 2021 capacity procurement and remained in the agreement for the subsequent capacity procurements to accommodate the changes to the MISO resource adequacy construct that would result in changes to the MISO capacity products to be procured for Ameren's eligible customers. As a result of FERC approval of MISO's Seasonal Capacity and Accreditation Requirements filling, (as discussed in Chapter 5) an update to the current Ameren Capacity Agreement was necessary prior to the Early 2023 Capacity Procurement event as discussed in Chapter 7.

In the procurement events conducted for energy blocks since 2012, comments have been few, with virtually no new modifications being accepted or made (in part because some comments made by new participants have been handled in prior procurement events). The documents used for the 2012 IPA-run procurement events illustrate both the breadth and depth of bidder input to the current state of the documents and the maturity of the documents themselves. The contract documents utilized for the MidAmerican energy blocks procurement events were, and continue to be, similar to the Ameren Illinois contract documents.

Since electricity markets are dynamic, periodic review of contract terms is necessary to ensure proper protection for the utilities, utility customers, and suppliers. Therefore, the IPA recommends that the most recently used forms, namely the energy contracts used in the 2024 procurement events, are the starting point for the contracts used in the energy procurements associated with this Plan. The IPA also recommends that the IPA, Commission Staff, Procurement Administrator, Procurement Monitor, and utilities undertake a joint review of such contracts in order to identify what terms, if any, need to be modified.

In the ICC docket that litigated the IPA's 2023 Electricity Procurement Plan, several arguments were raised by ComEd related to the consideration of bids based upon fuel mix, as well as the disclosure of the fuel mix at the time a bid is made and the publication of the fuel mix of winning bids. The Commission found that the law prohibits the consideration of fuel mix in bid evaluation, and confidentiality provisions found in Section 16-111.5(h) of the Public Utilities Act prohibit the publication of the fuel mix of winning bids. Nonetheless, the Commission accepted a proposal to have bidders disclose the fuel source of their bids.[264] Aggregated expected fuel mix data were reported for the winning bidders in the Spring 2023 energy procurement, the Fall 2023 energy procurement, and the Spring 2024 energy procurement.[265]

8.2 IPA Recovery of Procurement Expenses

Section 1-75(h) of the IPA Act states that "[t]he Agency shall assess fees to each bidder to recover the costs incurred in connection with a competitive procurement process."[266] Additionally, in April 2014, the IPA adopted administrative rules related to fee assessments that codify past practices including defining "bidders" and "suppliers" in procurement events as well as the process for determining those fees.[267]

The IPA historically recovered the cost of procurement events through two types of fees:

- A "Bid Participation Fee," which is a flat fee paid by all bidders as a condition of qualification; and
- "Supplier Fees," which are paid only by the winning bidders as a fee per block won at the conclusion of the procurement event.

For the last several procurements, the Bid Participation Fee has been nominal ($500), which means that the bulk of the costs of the procurement event (which are typically several hundred thousand dollars) are recovered from winning bidders through Supplier Fees. There are two risks for the IPA from recovering costs in this manner:

1. If not all the blocks are procured (and no additional procurement event is held), the IPA will not recover the full cost of the procurement through the combination of the Bid Participation Fees and the Supplier Fees. The Supplier Fees are collected from the "winning bidders" based on the recommended blocks approved by the Commission; the Supplier Fees associated with the blocks that are not procured are not collected.

[264] See Docket No. 22-0590, Final Order dated December 15, 2022, at 12.

[265] See: https://ipa.illinois.gov/content/dam/soi/en/web/ipa/documents/42023/public-notice-of-sprint-2023-standard-energy-products-procurement-results-2023-04-23.pdf; https://www.ipa-energyrfp.com/wp-content/uploads/2023/09/Public-Notice-of-Fall-2023-Standard-Energy-Products-Procurement-Results-2023-09-14.pdf; https://www.ipa-energyrfp.com/wp-content/uploads/2024/04/Public-Notice-of-Spring-2024-Standard-Energy-Products-Procurement-Results-2024-04-18.pdf.

[266] 20 ILCS 3855/1-75(h).

[267] 83 Ill. Admin. Code. §§ 1200.110, 1200.220.

2. Suppliers may not necessarily pay the Supplier Fees on time (or pay them at all). Suppliers that have bids that are approved by the Commission proceed to the contract execution process with the utility and will get paid under that contract whether or not they have paid the Supplier Fees. When the structure of fees was first introduced, non-payment of the Supplier Fees was an event of default under the contract with the utility. Suppliers had a very strong incentive to pay the Supplier Fees as failure to do so meant that they would not be able to be compensated under the contract from winning the bid. As procurement events came to be IPA-run, this structure was abandoned as the responsibility for assessing fees to bidders belongs to the IPA and not the applicable utility. The incentives for suppliers to pay the Supplier Fees were reduced as a result.

In developing its procurement approach, the IPA has considered a number of approaches for addressing these risks, involving two broad categories of solutions:

a. Maintain the current fee structure and use the pre-bid letter of credit provided by bidders as bid assurance collateral to ensure compliance with the payment obligation of the Supplier Fees.
b. Change the current fee structure to have the cost of the procurement largely paid upfront and bar suppliers that fail to pay all fees due from participation in IPA-run events for a period of time.

Until the 2014 procurement events, the pre-bid letter of credit had been strictly a credit instrument held for the benefit of the utility and its customers. The utility was able to draw upon the pre-bid letter of credit if the supplier failed to complete the contract execution process. At that point, the utility that had filed its rates based on the winning bids would have to buy replacement supply, for which it could use funds under the pre-bid letter of credit to mitigate any impact of the default by a supplier on rates. Starting with the 2014 procurement events, the function of the pre-bid letter of credit was expanded to ensure payment of the Supplier Fees by adding a condition to the utility pre-bid letter of credit allowing the utility to draw on the letter of credit if the Supplier Fees are not paid by a certain date (and having an agreement between the IPA and the utility on how funds would flow back to the IPA for payment of the Supplier Fees). This is the approach that was used starting with the 2014 procurement events and continued through the 2024 procurement events.

The IPA has previously received comments on these possible approaches and how the IPA could ensure that, in conducting procurement events, it complies with Section 1-75(h) of the IPA Act and Section 1200.220 of Title 83 of the Illinois Administrative Code. Based on those comments and subsequent review of the alternatives, the IPA recommends that the approach used in the procurement events since 2014 be continued to support the procurement events recommended in this Plan. That approach is for the energy contracts to maintain the condition in the utility pre-bid letter of credit allowing the utility to draw if the Supplier Fees are not paid by a date certain. Likewise, as used in the recent procurement events, there will also be an agreement between the IPA and each utility on how funds would flow back to the IPA for payment of the Supplier Fees under this circumstance.

8.3 Two Procurement Events

Procurement events under the 2025 Electricity Procurement Plan will continue to be held in the spring and fall for the procurement of energy blocks and a portion of the necessary Ameren Illinois capacity products (Zonal Resource Credits and financial swap products).

8.4 Informal Hearing

Section 16-111.5(o) of the PUA states,

> *On or before June 1 of each year, the Commission shall hold an informal hearing for the purpose of receiving comments on the prior year's procurement process and any recommendations for change.*

On May 13, 2024, the ICC Staff posted a public notice[268] for the informal hearing to receive comments regarding the procurement process for the procurement events that were held from Summer 2023 through Spring 2024. The Summer 2023 procurement involved the procurement of MISO Seasonal Zonal Resource Credits. The

[268] Public Notice of Informal Hearing (Request for Comments) Concerning Electric Procurement Events Which Were Held from Summer 2023 through Spring 2024, Issued May 13, 2024, https://www.icc.illinois.gov/programs/Electricity-Procurement-Process-for-Plan-Years-Beginning-June-2024.

procurement event was originally scheduled for May 15, 2023 but was delayed to June 9, 2023 due to a delay in the posting and implementation of the results of the MISO PRA for the 2023-24 Delivery Year. The Fall 2023 procurement of standard energy products to meet a portion of the requirements of ComEd's and Ameren Illinois' eligible retail customers for October 2023 through May 2026 was held on September 11, 2023. The Fall 2023 capacity procurement event to procure seasonal MISO Zonal Resource Credits capacity products for Ameren Illinois was held on September 21, 2023. The Spring 2024 procurement events included the procurement of a portion of the three utilities' energy requirements to meet eligible retail customers' needs for the 2024-2025, 2025-2026, and 2026-2027 Delivery Years, as well as the procurement of seasonal MISO Zonal Resource Credits for Ameren Illinois for Spring 2026 delivery.

In response to the Commission's request for comments for the informal hearing, on May 17, 2024, Bates White Economic Consulting ("Bates White"), the ICC's Procurement Monitor, submitted comments which provided their perspective on the IPA's seven procurement events that were held from the Summer of 2023 through the Spring of 2024. [269]

In their comments, Bates White summarized the results of these procurements and noted that the IPA's procurements and hedging process continued to be successful in leveraging the power of competition for the benefit of the utilities' ratepayers. Bates White also expressed continued support for the IPA's use of competitive procurements with bids subject to confidential benchmarks as the best practices that benefit ratepayers. Bates White commented on the reduction in the number of energy blocks procured for ComEd's eligible retail customers which sought to recognize the value of using CMCs to partially offset energy price volatility for these customers. Bates White did not identify any "red flags or strong evidence of material impacts to ComEd procurement results since the recognition of CMC contracts (and associated reductions in ComEd target blocks to procure)."

[269] See: https://www.icc.illinois.gov/programs/Electricity-Procurement-Process-for-Plan-Years-Beginning-June-2024.

Appendices (Overview)

Appendices are available separately at:
https://ipa.illinois.gov/energy-procurement/2025-appendices.html

Note, the term "Expected Case" used in these appendices is synonymous with "Base Case" used in the main body of the Plan.

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