2023

ELECTRICITY PROCUREMENT PLAN

2023 Draft Plan for Comment

August 15, 2022

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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1 Executive Summary

This is the fifteenth electricity procurement plan (the "Plan," "Procurement Plan," "2023 Plan," or "2023 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 seventh time in the 2022 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 2023 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 2023-2024 Delivery Year[2] and lasts through the 2027-2028 Delivery Year.

The 2022 Procurement Plan, as approved by the Commission in Docket No. 21-0717, called for the energy requirements for Ameren Illinois, ComEd, and MidAmerican to be procured by the IPA through two block energy procurements (Spring 2022 and Fall 2022). In addition, the 2022 Plan included two capacity procurements for Ameren Illinois (Spring 2022 and Fall 2022). The 2022 Procurement Plan also recommended a continuation of the energy procurement strategies proposed in the 2021 Procurement Plan. An unusually high level of price volatility leading up to, and on the day of, the spring procurement resulted in not all blocks being filled, and the Agency held a supplemental procurement to procure additional blocks for the summer months.

In response to these changes in energy markets, the Agency conducted a stakeholder feedback process in June and July 2022 to assist the Agency in considering what changes could be made to its procurement approach for this draft 2023 Electricity Procurement Plan. The Agency appreciates the feedback provided, including feedback not adopted. The IPA proposes to continue the energy procurement schedule and hedging approach utilized in the 2022 Plan for the Agency's 2023 Plan with two changes. First, the IPA proposes to increase the hedging percentage target for the summer months in procurements prior to the final spring procurement event in order to reduce the remaining volumes to be procured for the prompt summer months. Second, the IPA proposes to increase the amount of capacity hedged for Ameren Illinois from 50% to 75%.

1.1 Power Procurement Strategy

The 2023 Plan proposes to 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

[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 2023 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).

environmentally sustainable electric service at the lowest total cost over time, taking into account any benefits of price stability."[3]

The IPA's energy hedging strategy for the 2023 Procurement Plan is consistent with the strategy used for the 2022 Plan. That strategy involves the procurement of hedges in 2023 to meet a portion of anticipated eligible retail customer energy supply requirements for a three-year period and includes two block energy procurement events, one in the Spring and the second in the Fall. One change that is proposed is to decrease the amount of summer blocks procured in the prompt Spring procurement by increasing the hedging percentages for prior procurements. Details of this procurement strategy can be found in Section 7.1.

Additionally, for Ameren Illinois, for the 2024-2025 Delivery Year, the IPA recommends continuing the strategy of procuring a portion of its forecasted capacity requirements in bilateral transactions and the remaining balance through the MISO Planning Resource Auction ("PRA").[4] As explained in more detail in Section 5.2.2.2.4 and Section 7.2.1.2 the IPA is proposing to increase the amount of capacity it procures in bilateral transactions from 50% to 75% for the 2024-2025 Delivery Year. For the 2025-2026 Delivery Year, the IPA recommends procuring up to 25% of its forecasted capacity requirements in bilateral transactions in 2023, with the balance of forecast capacity requirement to be determined in the 2024 Electricity Procurement Plan. For ComEd, consistent with the strategy adopted in prior plans, the IPA proposes that its capacity requirements be secured by ComEd through the PJM Reliability Pricing Model process. Following the approach taken in the 2022 Plan, the IPA recommends that MidAmerican's forecasted capacity deficit be secured by MidAmerican through the annual MISO PRA.[5]

In addition to the various proposals above, the IPA recommends that ancillary services, load balancing services, and transmission services 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 proposed hedging strategy and planned procurements:

Table 1-1: Summary of Energy Hedging Strategy for all Utilities[6]

Spring 2023Procurement			**Fall 2023 Procurement**		
June 2023-May 2024 (Upcoming Delivery Year)	**Upcoming Delivery Year+1**	**Upcoming Delivery Year+2**	**October 2023-May 2024**	**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%.

[3] 20 ILCS 3855/1-20(a)(1).

[4] 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.

[5] 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).

[6] Table 1-1 shows the cumulative percentage of targeted load to be hedged by the conclusion of the indicated procurement events.

Table 1-2: Summary of Capacity Procurement for Ameren Illinois[7, 8]

June 2023-May 2024	June 2024-May 2025	June 2025-May 2026
12.5% in Spring 2021 25% in Fall 2021 37.5% in Spring 2022 50% in Fall 2022 100%, MISO PRA	12.5% in Spring 2022 25% in Fall 2022 50% in Spring 2023 75% in Fall 2023 100%, MISO PRA	12.5% in Spring 2023 25% in Fall 2023 Remainder to be determined in 2024 Plan

Table 1-3: Summary of Capacity Procurement for ComEd

June 2023-May 2024 (Upcoming Delivery Year)	June 2024-May 2025	June 2025-May 2026	June 2026-May 2027
100% PJM RPM Auctions	100% PJM RPM Auctions	100% PJM RPM Auctions	100% PJM RPM Auctions

Table 1-4: Summary of Capacity Procurement for MidAmerican

June 2023-May 2024 (Upcoming Delivery Year)	June 2024-May 2025	June 2025-May 2026
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."[9] Thus, the procurement of renewable energy resources is included in the IPA's Long-Term Renewable Resources Procurement 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. Concurrent with the release of the draft 2022 Electricity Procurement Plan, the Agency also published a draft of its Second Revised Long-Term Plan for public comment. Subsequent to that publication, the enactment of Public Act 102-0662 required the IPA to withdraw "any long-term renewable resources procurement plan update published by the Agency but not yet approved by the Illinois Commerce Commission[.]"[10]. The Agency

[7] Table 1-2 shows the cumulative up-to percentage of capacity targeted to be procured by the conclusion of the indicated procurement event.

[8] Procurement percentage targets for the 2023-2024, and 2024-2025 Delivery Years conducted in 2022 were approved under the 2022 Procurement Plan. Actual procurement volumes may not match percentage targets.

[9] 20 ILCS 3855/1-75(a).

[10] 20 ILCS 3855/1-75(c)(1)(A).

released a draft 2022 Long-Term Plan on January 13, 2022 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.

1.3 Procurement Recommendations

Table 1-5 summarizes the IPA's recommendations as described in this Plan.

Table 1-5: Summary of Procurement Plan Recommendations Based on July 15, 2022 Utility Load Forecast (Quantities to be Adjusted Based on the March and July 2023 Load Forecasts)

	Delivery Year	Energy	Capacity[11][12]	Transmission and Ancillary Services
Ameren Illinois	**2023-2024**	Up to 825 MW forecasted requirement (Spring Procurement) Up to 325 MW additional forecasted requirement (Fall Procurement)	Up to 12.5% in Spring 2021 Up to 25% RFP in Fall 2021 Up to 37.5% in Spring 2022 Up to 50% RFP in Fall 2022 Remaining balance from MISO PRA	Will be purchased from MISO
	2024-2025	Up to 350 MW forecasted requirement (Spring Procurement) Up to 375 MW forecasted requirement (Fall Procurement)	Up to 12.5% RFP in Spring 2022 Up to 25% RFP in Fall 2022 Up to 50% in Spring 2023 Up to 75% RFP in Fall 2023 Remaining balance from MISO PRA	Will be purchased from MISO
	2025-2026	Up to 200 MW forecasted requirement (Spring Procurement) Up to 200 MW forecasted requirement (Fall Procurement)	Up to 12.5% RFP in Spring 2023 Up to 25% RFP in Fall 2023[13] Remaining balance to be determined in 2024 Plan	Will be purchased from MISO
	2026-2027	No energy procurement required	No further action at this time	Will be purchased from MISO
	2027-2028	No energy procurement required	No further action at this time.	Will be purchased from MISO
ComEd	**2023-2024**	Up to 2,550 MW forecasted requirement (Spring Procurement) Up to 900 MW additional forecasted requirement (Fall Procurement)	100% PJM RPM Auctions	Will be purchased from PJM
	2024-2025	Up to 1,150 MW forecasted requirement (Spring Procurement) Up to 1,150 MW forecasted requirement (Fall Procurement)	100% PJM RPM Auctions	Will be purchased from PJM
	2025-2026	Up to 650 MW forecasted requirement (Spring Procurement) Up to 650 MW forecasted requirement (Fall Procurement)	100% PJM RPM Auctions	Will be purchased from PJM
	2026-2027	No energy procurement required	100% PJM RPM Auctions	Will be purchased from PJM
	2027-2028	No energy procurement required	No further action at this time	Will be purchased from PJM
MidAmerican	**2023-2024**	Up to 75 MW forecasted requirement (Spring Procurement) No additional energy procurement needed (Fall Procurement)	100% of expected deficit from MISO PRA	Will be purchased from MISO
	2024-2025	No energy procurement needed (Spring Procurement) No additional energy procurement needed (Fall Procurement)	100% of expected deficit from MISO PRA	Will be purchased from MISO
	2025-2026	No energy procurement required	100% of expected deficit from MISO PRA	Will be purchased from MISO
	2026-2027	No energy procurement required	No further action at this time	Will be purchased from MISO
	2027-2028	No energy procurement required	No further action at this time	Will be purchased from MISO

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

[12] Procurement percentage targets for the 2023-2024, and 2024-2025 Delivery Years conducted in 2022 were approved under the 2022 Electricity Procurement Plan. Actual procurement volumes may not match percentage targets.

[13] Additional Procurements for the 2025-2026 Delivery Year will be considered in the 2024 Procurement Plan.

1.4 The Action Plan

In this Plan, the IPA recommends the following items for ICC action:

1. Approve the base case load forecasts of ComEd, Ameren Illinois, and MidAmerican as submitted in July 2022.
2. Approve two energy procurement events scheduled for Spring 2023 and Fall 2023. The energy amounts to be procured in the spring will be based on the updated March 15, 2023 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, 2023 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.
3. Approve two capacity procurement events for Ameren Illinois scheduled for Spring 2023 and Fall 2023. The up-to capacity amounts to be procured in the spring will be based on the updated March 15, 2023 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 up-to capacity amounts to be procured in the fall will be based on the July 15, 2023 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 15, 2023 and the July 15, 2023 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 its March 15, 2023 forecast update 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 2022 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 publishes this draft 2023 Procurement Plan for public comment and invites the affected utilities and any interested parties to submit comments on the Plan to the Agency by September 14, 2022.

2 Legislative/Regulatory Requirements of the Plan

This Section of the 2023 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.

Public Act 99-0906, which became effective on June 1, 2017, substantially modified what elements are to be included in the IPA's annual "power procurement plan." Starting with the 2018 Procurement Plan, the IPA no longer includes the procurement of renewable energy resources as part of the annual procurement plan.[14] The procurement of renewable energy resources to comply with the Illinois Renewable Portfolio Standard ("RPS") requirements in Section 1-75(c) of the IPA Act is instead addressed through the IPA's separately-developed Long-Term Renewable Resources Procurement Plan. The requirements of the Long-Term Plan were further modified by Public Act 102-0662, which became effective on September 15, 2021.

Public Act 99-0906 also included revisions to the state's energy efficiency portfolio standard (found in Section 8-103 of the PUA) as well as the elimination of the mechanism through which incremental energy efficiency programs were included in IPA procurement plans under Section 16-111.5B of the PUA.[15] The 2022 Procurement Plan is focused only on the procurement of standard wholesale power products to meet the needs of the Ameren Illinois, ComEd and MidAmerican eligible retail customers.

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"),[16] benefit from retail and wholesale competition. The original objective of the IPA Act was to improve the process to procure electricity for those customers.[17] 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."[18] 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.[19] 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.[20] 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"[21] and

[14] See 20 ILCS 3855/1-75(a); 220 ILCS 5/16-111.5(b)(5).

[15] See 220 ILCS 5/16-111.5B(a)(5) ("The requirements set forth in paragraphs (1) through (5) of this subsection (a)" – i.e., the solicitation, inclusion, and approval of incremental energy efficiency programs in IPA procurement plans – "shall terminate after the filing of the procurement plan in 2015, and no energy efficiency shall be procured by the Agency thereafter. Energy efficiency programs approved previously under this Section shall terminate no later than December 31, 2017.").

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

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

[18] 20 ILCS 3855/1-5(1).

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

[20] 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.")

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

"Procurement Administrator."[22] The Commission is tasked with approval of the plan and monitoring of the procurement events through a Commission-hired "Procurement Monitor."[23]

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);[24] 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);[25] and the elimination of the statutory requirement that the Agency include cost-effective incremental energy efficiency programs in its annual power procurement plan.[26]

Public Act 102-0662, effective September 15, 2021, contained significant additional changes to the IPA's renewable energy credit procurement obligations, and the Agency was tasked with the development of a new procurement plan for the procurement of carbon mitigation credits from at-risk nuclear facilities.[27] 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.[28]

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 2023 Procurement Plan began on July 15, 2022. 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 prepares a draft Procurement Plan. The Draft 2023 Plan was made available for public review and comment on August 15, 2022. The Public Utilities Act provides for a 30-day comment period starting on the day the IPA releases its draft plan. The 2023 Plan comment period is scheduled to conclude on September 14, 2022. In prior years, during the 30-day comment period, the Agency has held in-person public hearings within each participating utility's service area to receive public comment on the draft Procurement Plan. Due to the ongoing COVID-19 pandemic, the Agency plans to hold public hearings for the 2023 Plan virtually in lieu of the separate meetings in each utility's service area.[29]

[22] 20 ILCS 3855/1-75(a)(2).

[23] 220 ILCS 5/16-111.5(b), (c)(2).

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

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

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

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

[28] 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."

[29] The virtual public hearings on the Draft 2023 Plan will be held using the Zoom platform at 12:00 p.m. (Ameren Illinois), 1:00 p.m. (ComEd), and 2:00 p.m. (MidAmerican) on Friday September 7, 2022.

After the receipt of comments, the IPA may revise 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.[30] The IPA's 2023 Plan will be filed with the Commission on September 28, 2022. Within 5 days after the Plan is filed with the Commission, parties may file Objections.[31]

Under the PUA, the Commission approves the Procurement Plan, including the load forecasts used in the Plan, 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."[32]

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 analysis; known or projected changes to future loads; and growth forecasts by customer class.[33] 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.[34] 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,[35] 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.[36]
- 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.[37] 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.[38]
- Procurements of standard wholesale products may now include energy from high voltage direct current ("HVDC") transmission lines with converter stations located in Illinois.[39] 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.
- Detail the proposed term structures for each wholesale product type included in the portfolio of products.[40]

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

[31] 220 ILCS 5/16-111.5(d)(3).

[32] 220 ILCS 5/16-111.5(d)(4).

[33] 220 ILCS 5/16-111.5(b)(1)(i)-(iv).

[34] 220 ILCS 5/16-111.5(b)(2), (b)(2)(i).

[35] 220 ILCS 5/16-111.5(b)(3).

[36] 220 ILCS 5/16-111.5(b)(i), (b)(iii).

[37] 220 ILCS 5/16-111.5(b)(3)(iv).

[38] Id.

[39] Id. (as amended by P.A. 102-0662).

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

- 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.[41] 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. [42]
- Include demand-response products, as discussed below.

2.4 Standard Product Procurement

As noted in Section 2.3, the IPA Act provides examples of "standard wholesale products."[43] This listing has been understood by the Commission to be non-exhaustive and non-static. [44] 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."[45]

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,[46] 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. [47] 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."[48]

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

[41] 220 ILCS 5/16-111.5(b)(3)(vi).

[42] 220 ILCS 5/16-111.5(b)(4).

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

[44] 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").

[45] Id.

[46] 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").

[47] 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).

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

executed during the next year, to meet the expected load requirements that will not be met through preexisting contracts."[49] 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.[50] Specifically:

- The demand-response measures must be procured by a demand-response provider from eligible retail customers;[51]
- 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;[52]
- The products must provide for customers' participation in the stream of benefits produced by the demand-response products; [53]
- 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;[54] 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.[55]

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.[56] 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.[57] 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.[58] 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.[59] These Plans were both approved by the Commission on September 11, 2017.[60]

Ameren Illinois and ComEd filed new energy efficiency plans as required by March 1, 2021 to cover the 2022-2025 period.[61] Ameren once again proposed to achieve its demand response goal through coincident peak

[49] 220 ILCS 5/16-111.5(b)(3)(ii).

[50] Id.

[51] 220 ILCS 5/16-111.5(b)(3)(ii)(A).

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

[53] 220 ILCS 5/16-111.5(b)(3)(ii)(C).

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

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

[56] 220 ILCS 5/16-108.6(g).

[57] 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.

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

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

[60] 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.

[61] 220 ILCS 5/8-103B(f)(2).

demand reduction achieved by the energy efficiency portfolio; this proposal was approved by the Commission on July 22, 2021.[62] 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.[63]

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.[64] As a part of the goal, the Plan must also include electricity generated from clean coal facilities.[65] While there is a broader definition of "clean coal facility" contained in the definition section of the IPA Act,[66] Section 1-75(d) describes two special cases: the "initial clean coal facility"[67] 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" (i.e., "retrofit clean coal facility").[68] 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.[69] 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.[70] The FutureGen Alliance's Board of Directors "approved a resolution, dated January 6, 2016, ceasing all FutureGen Project development efforts"[71] 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.[72]

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.[73] With energy efficiency also no longer falling under the IPA's annual electricity procurement

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

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

[64] 20 ILCS 3855/1-75(d).

[65] 20 ILCS 3855/1-75(d)(1).

[66] 20 ILCS 3855/1-10.

[67] Id.

[68] 20 ILCS 3855/1-75(d)(5).

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

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

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

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

[73] 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)).

planning process, the number of contested issues and intensity of arguments in attaining approval of the IPA's annual procurement plans has been reduced significantly: just two contested issues for the 2018 Plan, no contested issues for the 2019 Plan, only one contested issue for the 2020 Plan approval proceeding, and no contested issues for the 2021 and 2022 annual electricity procurement plan approval proceedings.

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.[74] 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 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.

Recent passage of omnibus energy legislation, often referred to as the Climate and Equitable Jobs Act, through Public Act 102-0662 (effective September 15, 2021) has massively expanded the Agency's workload. Most new responsibilities assigned to the IPA under Public Act 102-0662, such as the carbon mitigation credit procurement and coal-to-solar procurements, are 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 arguments received during stakeholder comment processes about altering electricity procurement hedging strategies for ComEd based on the presence of carbon mitigation credit delivery contracts).

With CEJA having passed in September 2021 and early adjournment of the Illinois General Assembly scheduled for early April of 2022, no legislation was passed in Spring 2022 session of the 102nd Illinois General Assembly that impacts this annual electricity procurement plan. The Agency will continue to monitor the development of any new energy legislation throughout the pendency of this Plan's consideration and approval, including during the Illinois General Assembly's scheduled November 2022 veto session.

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.[75] 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,[76] and on October 16, 2017, U.S. EPA published a Proposed Rule to repeal the Clean Power Plan.[77] 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

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

[75] 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.

[76] 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.

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

from existing electric generating units, written comments were due by February 26, 2018.[78] 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.[79]

The U.S. EPA released its proposed rulemaking, titled the "Affordable Clean Energy" ("ACE") rule, on August 21, 2018.[80] 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).[81] 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).[82]

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.[83] 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.[84] 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.[85]

As of the August 15, 2022 release of the draft 2023 Electricity Procurement Plan, the Senate and House have just recently passed the Inflation Reduction Act of 2022 and it is expected to be signed into law by U.S. President Joe Biden. 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.[86] The electricity markets will likely be impacted by increased 45Q tax credits[87] providing incentives to install economically viable carbon capture and storage technologies at new and existing natural gas power plants and existing coal power plants.

Additionally, the Agency is actively monitoring developments at the Federal Energy Regulatory Commission ("FERC") regarding capacity market constructs for PJM and MISO, the two Regional Transmission Organizations that Illinois is part of, including the recent FERC Order on PJM capacity market design. These are discussed further in Chapter 5 below.

[78] 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.

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

[80] 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.

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

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

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

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

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

[86] 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.

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

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."[88] 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[89] for a portion of its load.[90] 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.[91]

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.*[92]

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, 2023 – May 31, 2028 (See Appendix B)
- Spreadsheets of the expected (base), high, and low load forecasts. (Summarized in Appendix E)

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[88] 220 ILCS 5/16-111.5(a).

[89] 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.

[90] 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 eighth annual procurement process in which MidAmerican elected to have the IPA procure power and energy for a portion of its Illinois jurisdictional load.

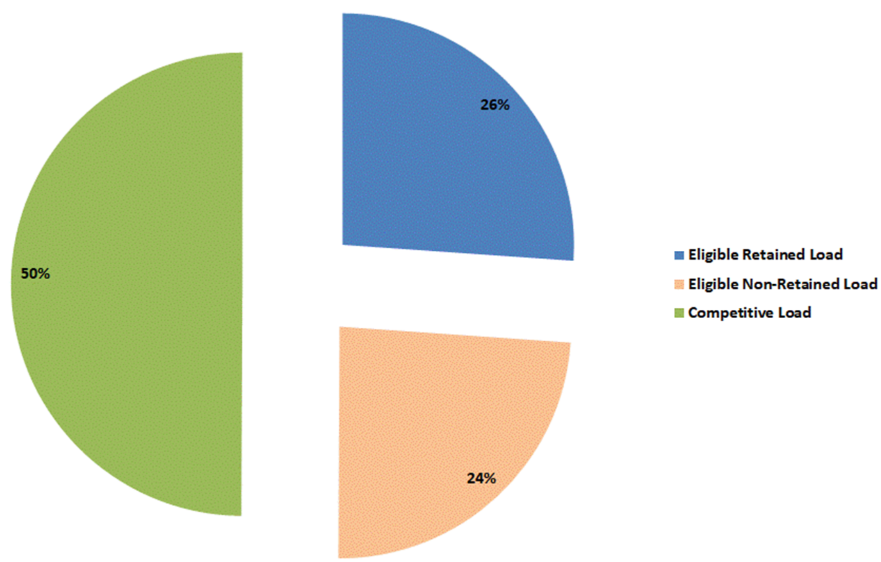
[91] 220 ILCS 5/16-111.5(b)(1).

[92] 220 ILCS 5/16-111.5(d)(1).

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 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.[93]

Figure 3-1: Ameren Illinois' Forecast Retail Customer Load Breakdown, Delivery Year 2023-2024[94]

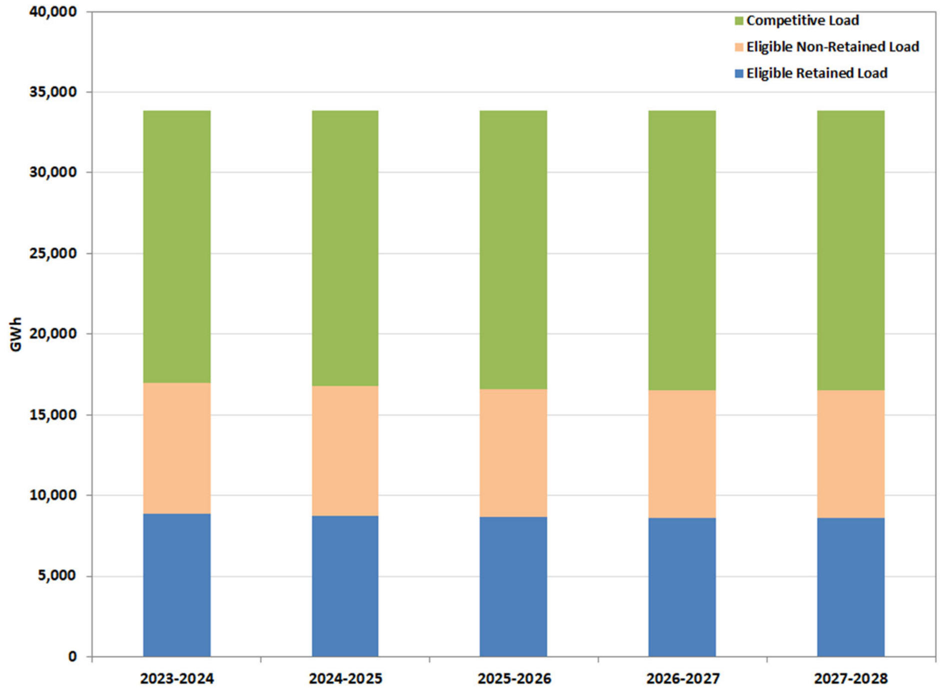


Ameren Illinois' forecasts are performed on the total Ameren Illinois delivery service load using a regression model applied to historical load and weather data. A separate analysis is performed for each customer class to account for the differing impacts of weather on the different customer classes.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

[93] 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.

[94] For the 2023-2024 Delivery Year, Ameren Illinois' projected total Retail Load is forecasted to be 33,873,550 MWh, where the Eligible Retained Load accounts for 8,839,303 MWh, the Eligible Non-Retained Load accounts for 8,123,533 MWh, and the Competitive Load accounts for 16,910,714 MWh. The amount for the projected total Retail Load was provided by Ameren in their July 2022 response to the IPA Data Request for the update of the Final Revised Long-Term Plan.

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

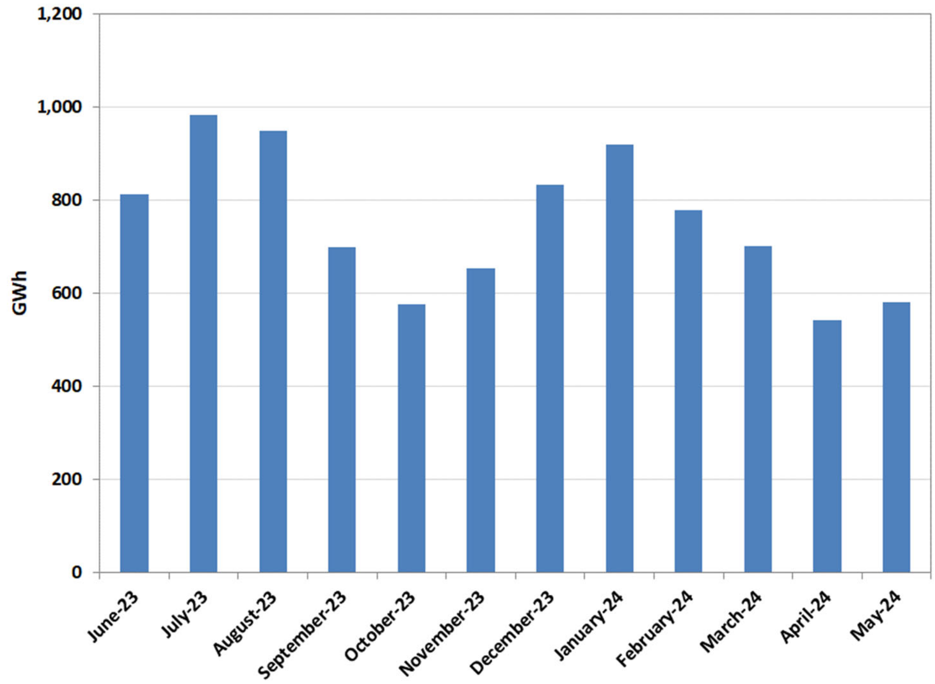


Ameren Illinois applies assumed "switching rates" to the total system load forecast to remove the load to be served by bundled hourly pricing (Power Smart Pricing or Rider HSS) and Alternative Retail Electric Suppliers, including municipal aggregation.[95] Ameren Illinois establishes the current customer 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.

[95] 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 excursion 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 -1.1%. For commercial customers, the growth rate for Ameren Illinois is projected to be -0.9%. While for industrial customers, the growth rate for Ameren Illinois is projected to be 1.5%.

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 May 1, 2022, customer switching has resulted in approximately 58% of residential and 66% 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."[96] The majority of municipal aggregation contracts that are set to expire in this planning cycle occur in December 2022 and January 2023. Ameren provided multiple load forecasts representing different switching scenarios.[97] 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 46% and 54%, respectively, in May 2023, 39% and 47%, respectively, in May 2024, and 0% and 22%, respectively, by the end of the planning horizon.

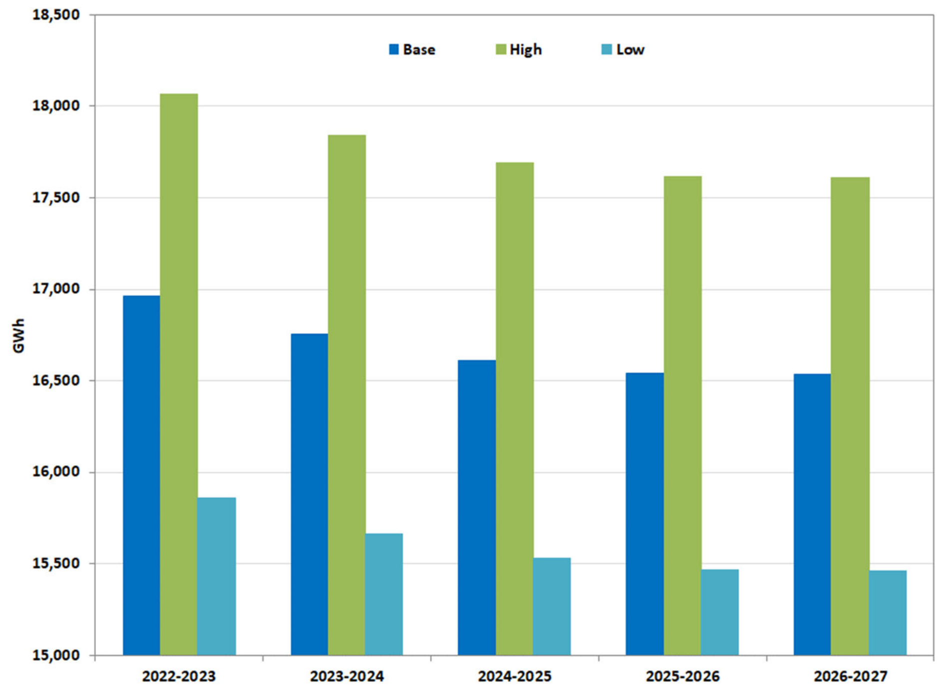
Conversely, should future Ameren Illinois tariff rates exceed customers' perceived value of ARES contracts, a higher switching scenario is possible. Thus, Ameren Illinois' high switching and a corresponding low load scenario assumes that residential and small commercial switching rates will approach 52% and 71%, respectively, in May 2023, 57% and 76%, respectively, in May 2024, and 76% and 95%, respectively, by the end of the planning horizon.

[96] See Ameren Load Forecast Submittal, Appendix B at https://ipa.illinois.gov/energy-procurement/2023-appendices.html.

[97] 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 2023 load forecasts and procurement volumes adjusted accordingly.

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.

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

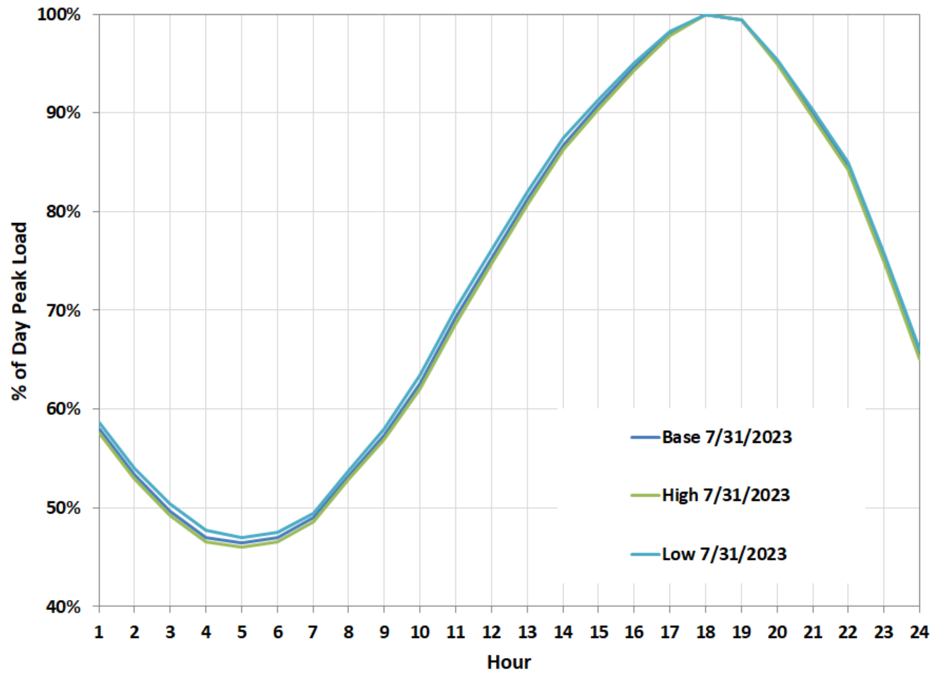
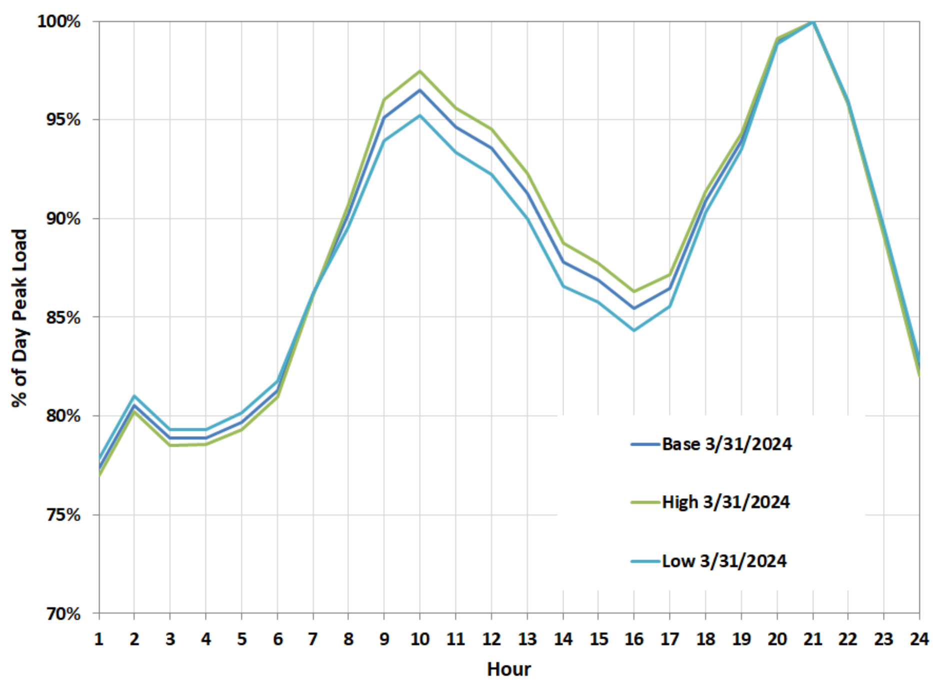


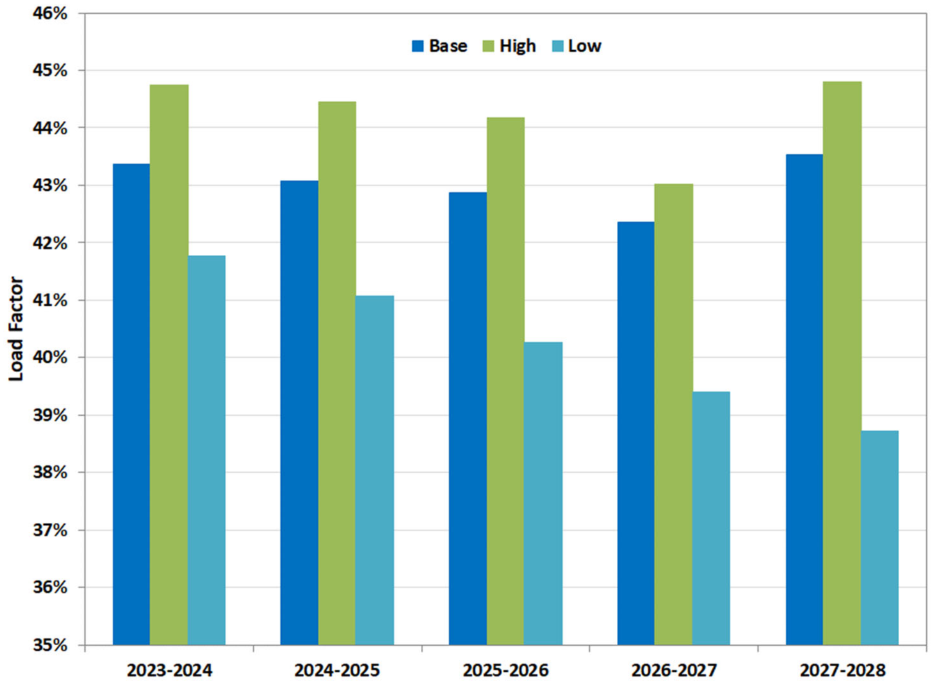
Figure 3-6: Sample Daily Load Shape, Spring Day in Ameren Illinois' Forecasts



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:

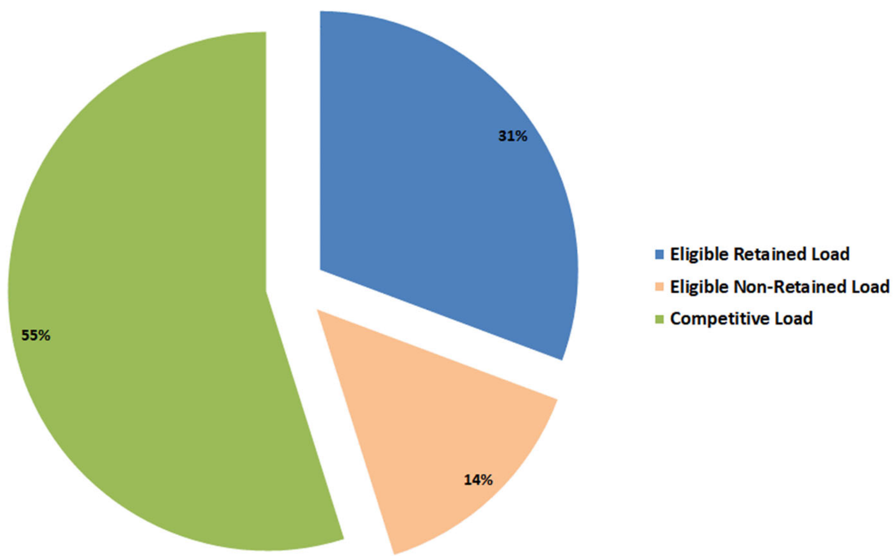
- *Load Forecast for Five-Year Planning Period June 2023 – May2028.* (See Appendix C) This document also contained several appendices.
- Information supporting the load forecasts including spreadsheets of load profiles, hourly load strips, model inputs, procurement blocks, and scenario models for the base, high and low forecasts. (Summarized in Appendix F)[98]

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.

[98] In its July 15, 2022 Load Forecast, ComEd also included a brief discussion of the distributed generation penetration effect in its service territory.

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.

Figure 3-8: ComEd's Forecast Retail Customer Load Breakdown, Delivery Year 2023-2024[99]



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.

[99] For the 2023-2024 Delivery Year, ComEd's projected total Retail Load is 84,578 GWh, where the Eligible Retained Load accounts for 25,963 GWh, the Eligible Non-Retained Load accounts for 12,213 GWh, and the Competitive Load accounts for 46,402 GWh. The amount for the projected total Retail Load was provided by ComEd in their July 2022 response to the IPA Data Request for the update of the Final Revised Long-Term Plan.

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

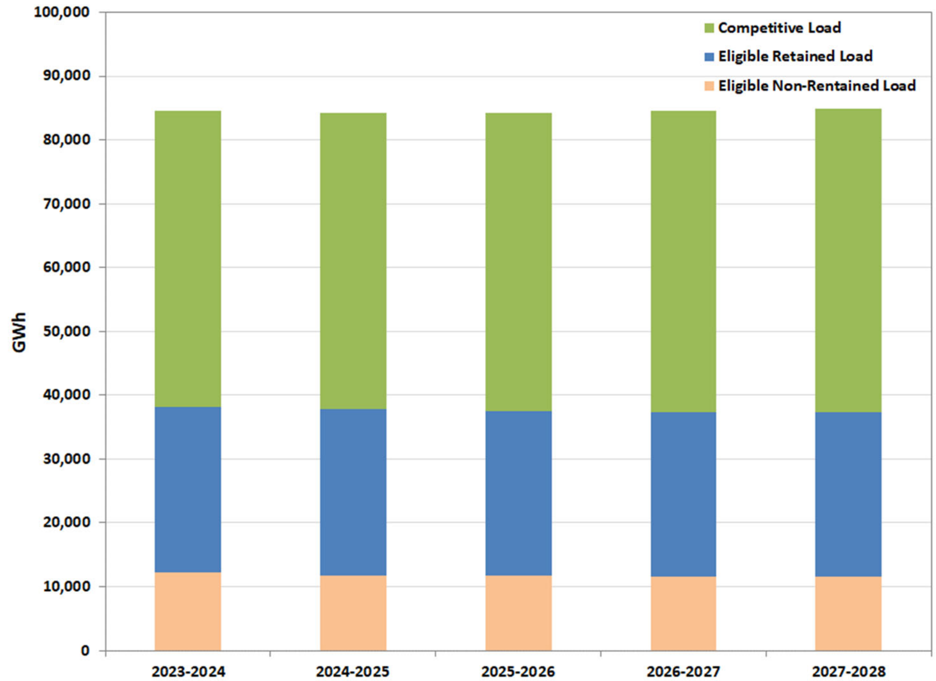
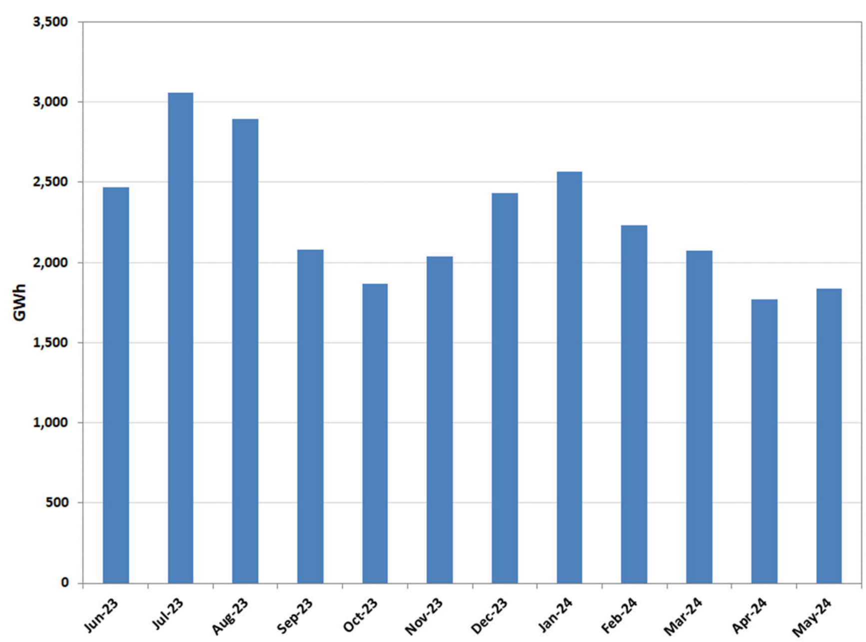


Figure 3-10 provides a monthly breakdown of the base-case forecast of ComEd's eligible retail customer load, that is, the load of customers who are forecasted to take bundled supply under this Procurement Plan.

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).

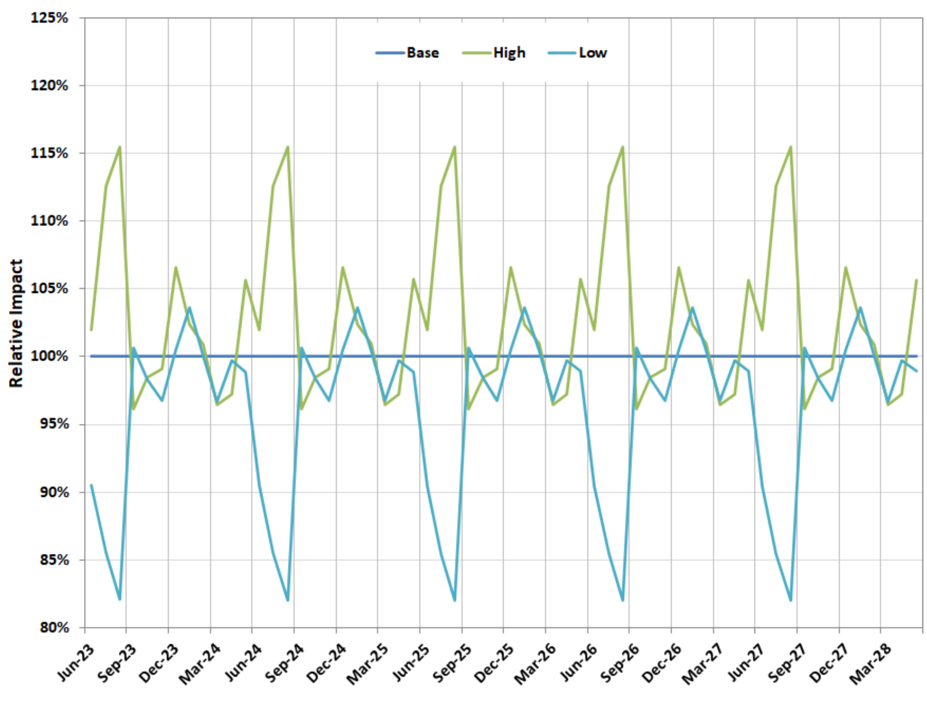
3.3.2 Weather

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

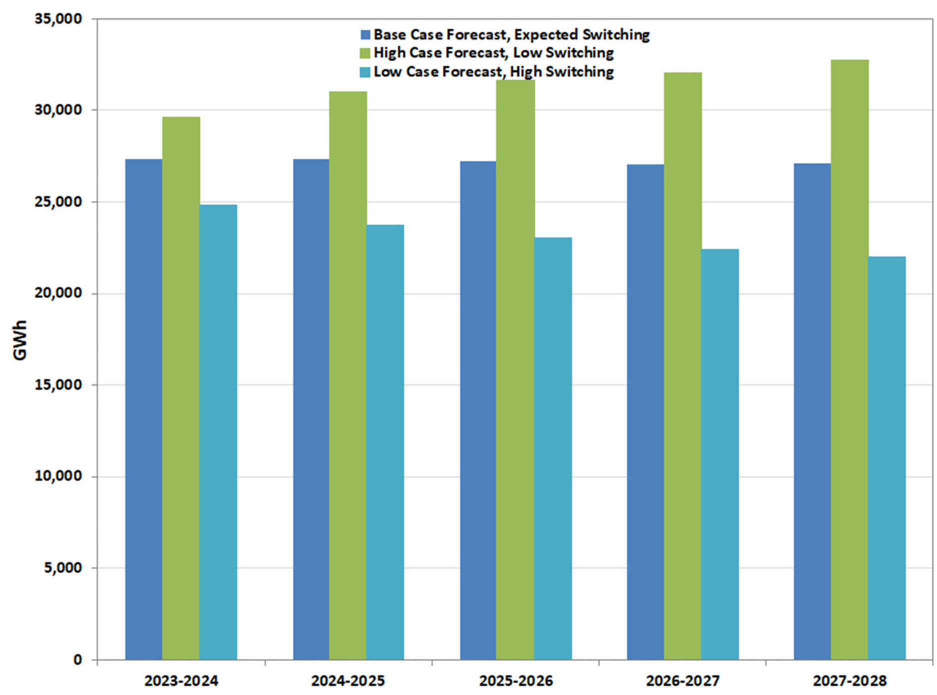


3.3.3 Switching

The high switching (low load) case assumes residential, watt-hour, and 0 to 100 kW blended service[100] usage will be reduced by 4% from the expected load level over the course of the calendar years 2023 and 2024 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 2022, with 197 of those communities actively being served through municipal aggregation (a decrease from 228 in June 2021). The percentage of potentially eligible retail customers taking blended service in this switching scenario is 65% (based on usage) as of December 2024 compared to 69% in the expected load forecast.

The low switching (high load) case assumes additional communities opt out of municipal aggregation in the years 2022 and 2023 such that residential usage increases by 4% from the expected load level over the course of the calendar years 2022 and 2023. The percentage of potentially eligible retail customers taking blended service in this switching scenario is 73% (based on usage) as of December 2024 compared to 69% in the expected load forecast. Figure 3-17 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

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

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.

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

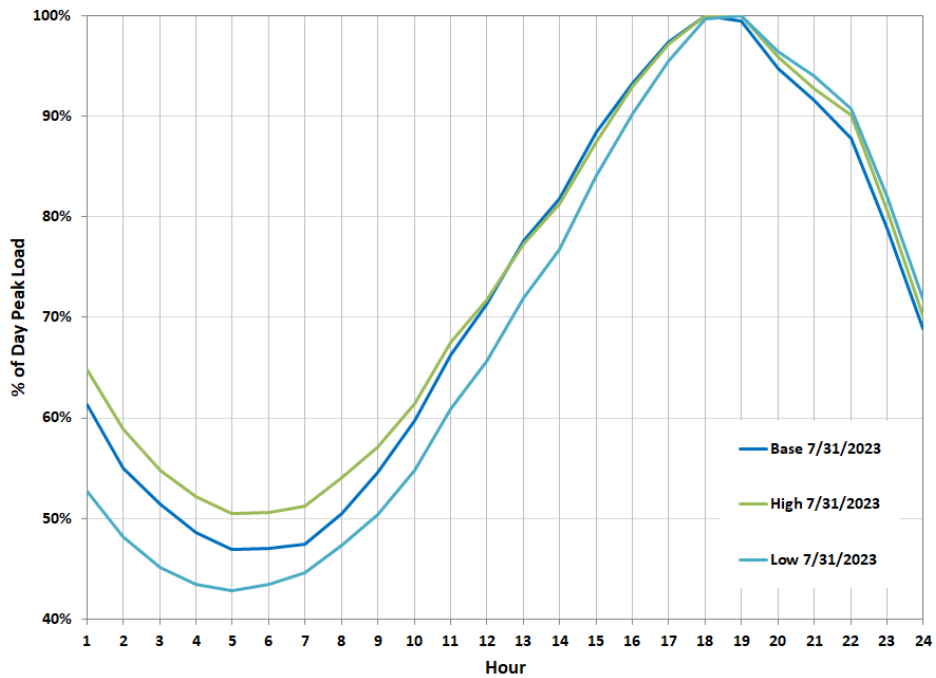
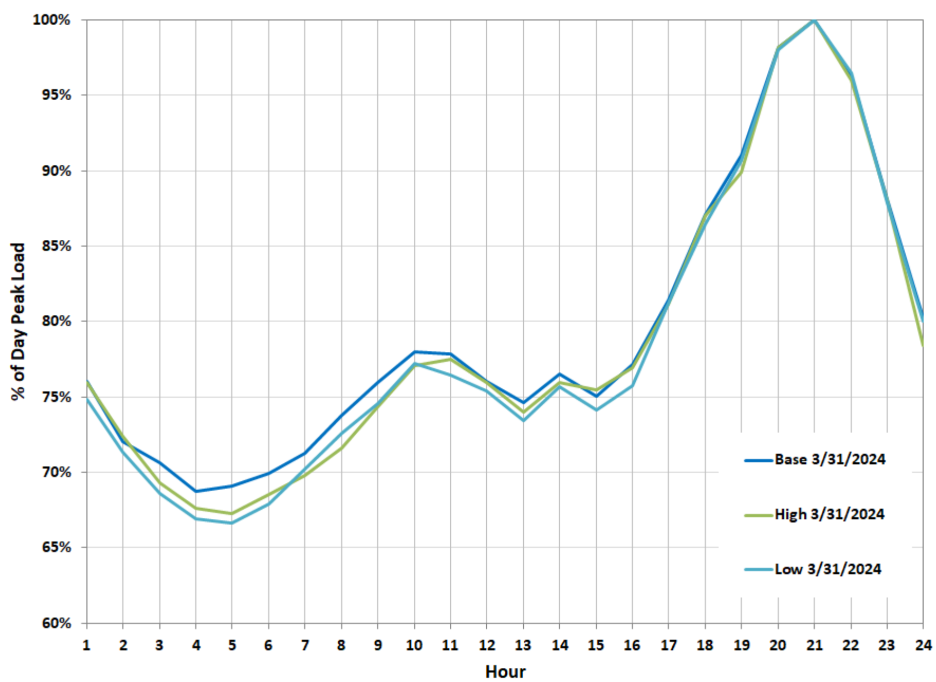
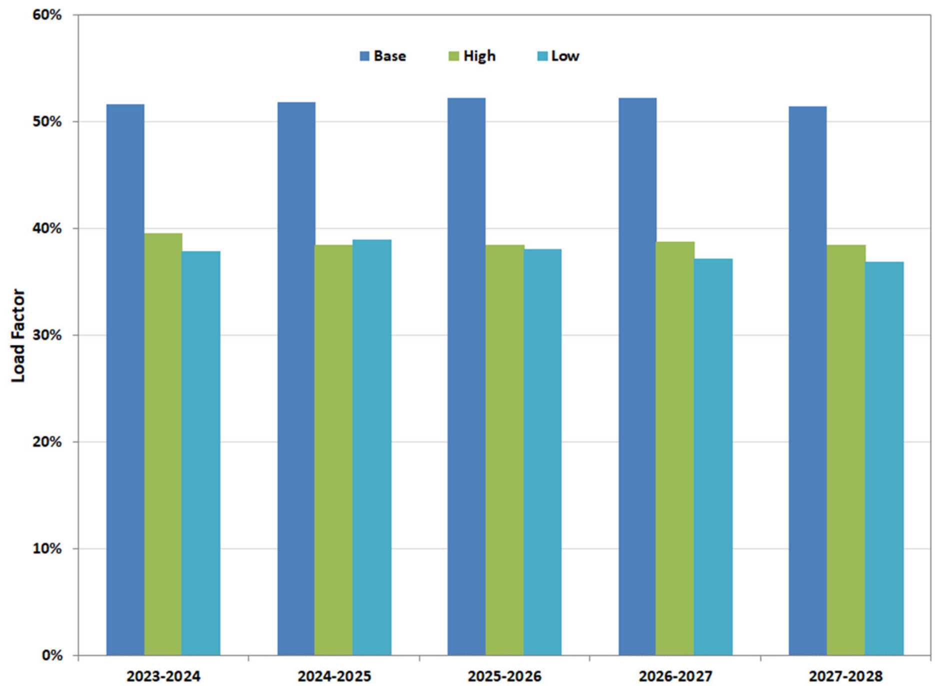


Figure 3-14: Sample Daily Load Shape, Spring Day in ComEd's Forecasts



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:

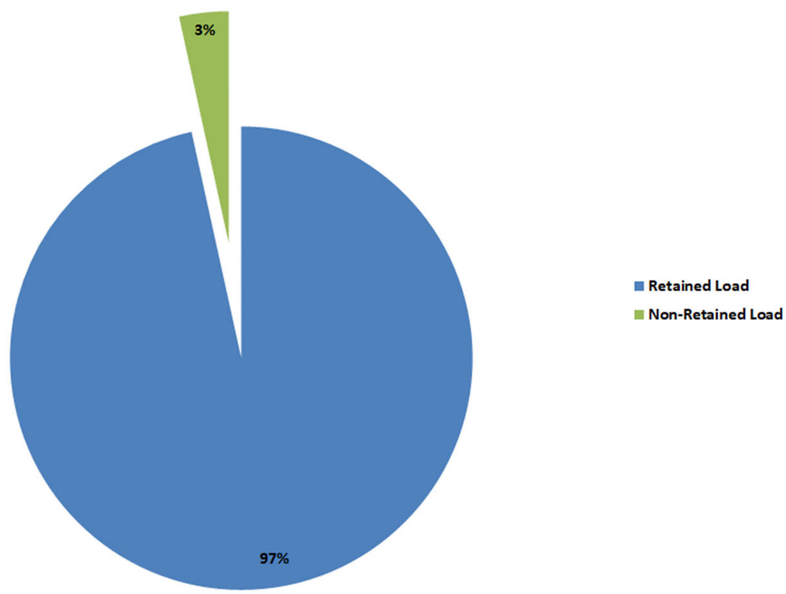
- *Methodology for the 2022-2031 Illinois Electric Customers and Sales Forecasts.* This document contained a discussion of load forecast methodology for all MidAmerican scenarios and supporting data for the base scenario forecast. The load forecast included a multi-year historical analysis of hourly 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 Ameren'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 2023-2024[101]



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

[101] For the 2023-2024 Delivery Year, MidAmerican's projected total Retail Load is 2,096,015 MWh, where the Eligible Retained Load accounts for 2,024,026 MWh and the Eligible Non-retained Load accounts for 71,990 MWh. The amount for the projected total Retail Load was provided by MidAmerican in their July 2022 response to the IPA Data Request for the update of the Final Revised Long-Term Plan.

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.

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

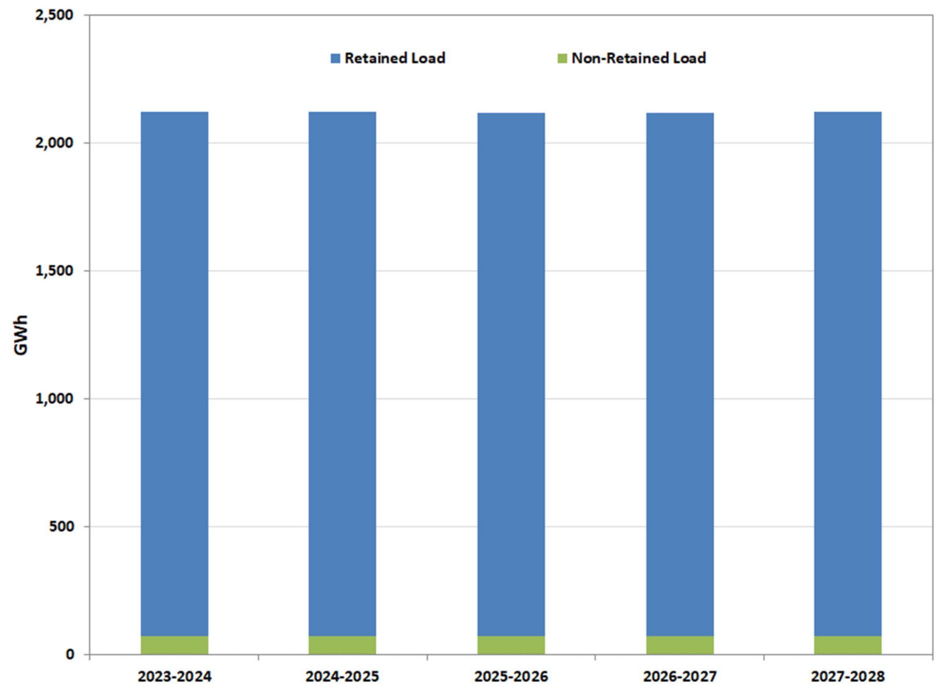
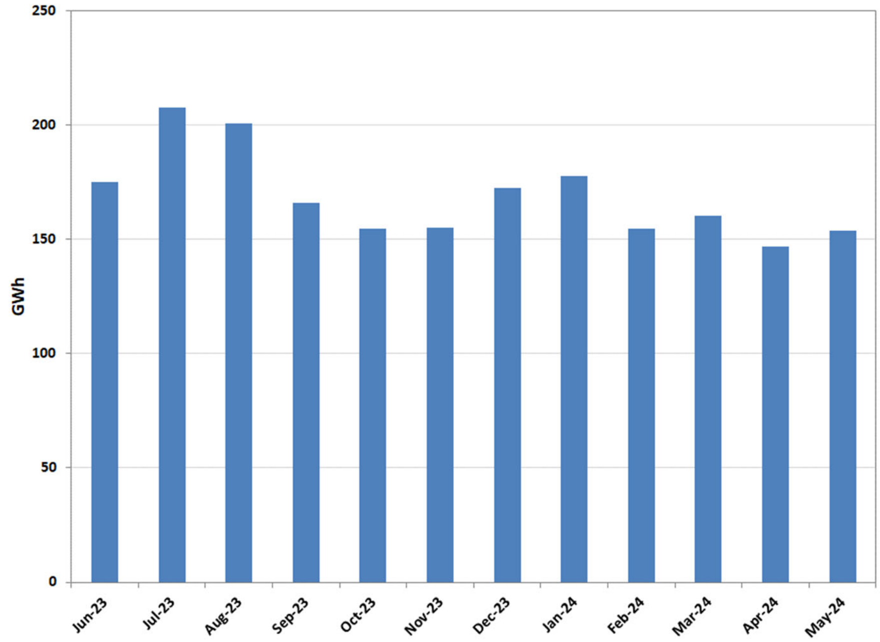


Figure 3-18 provides a monthly breakdown of the base case forecast of MidAmerican retained eligible retail customer load, that is, the load of customers on bundled supply to be considered under this Procurement Plan.

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 projected to grow approximately 0.05% annually in Illinois.

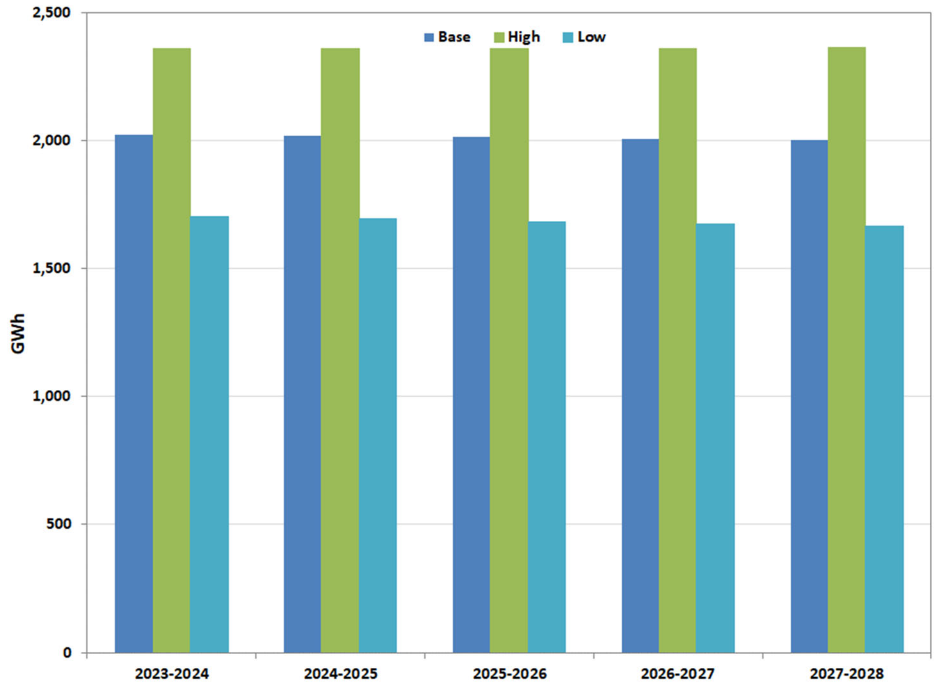
3.4.2 Weather

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

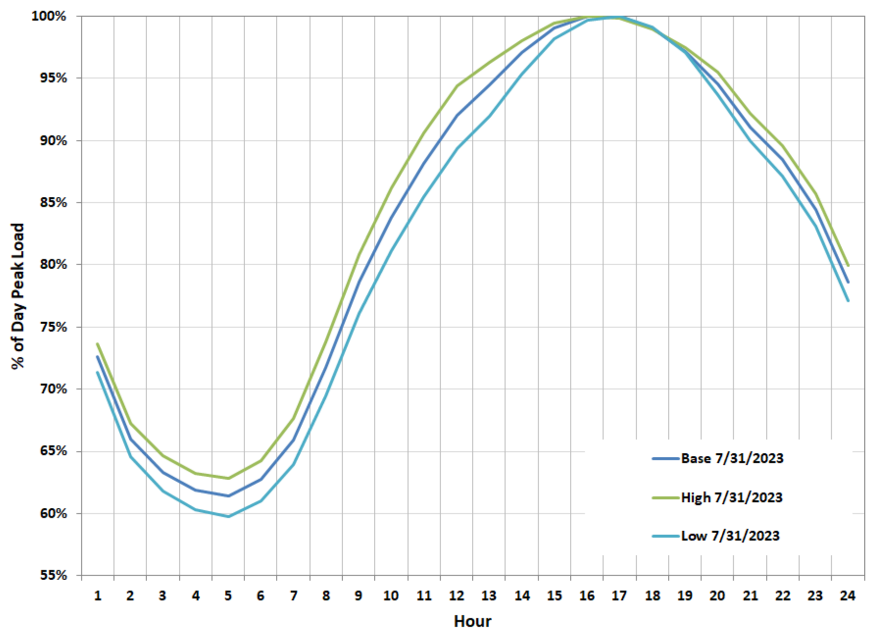
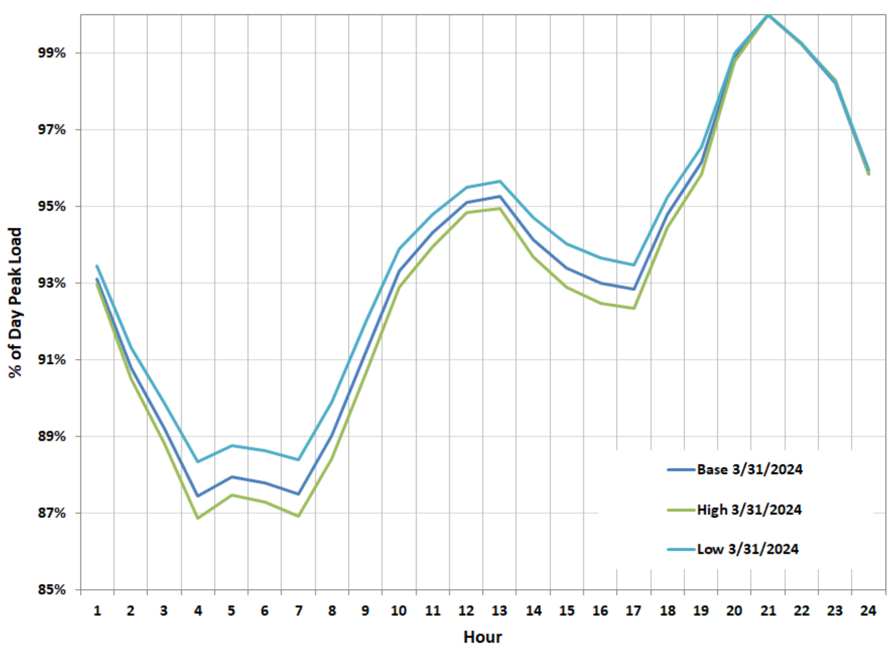
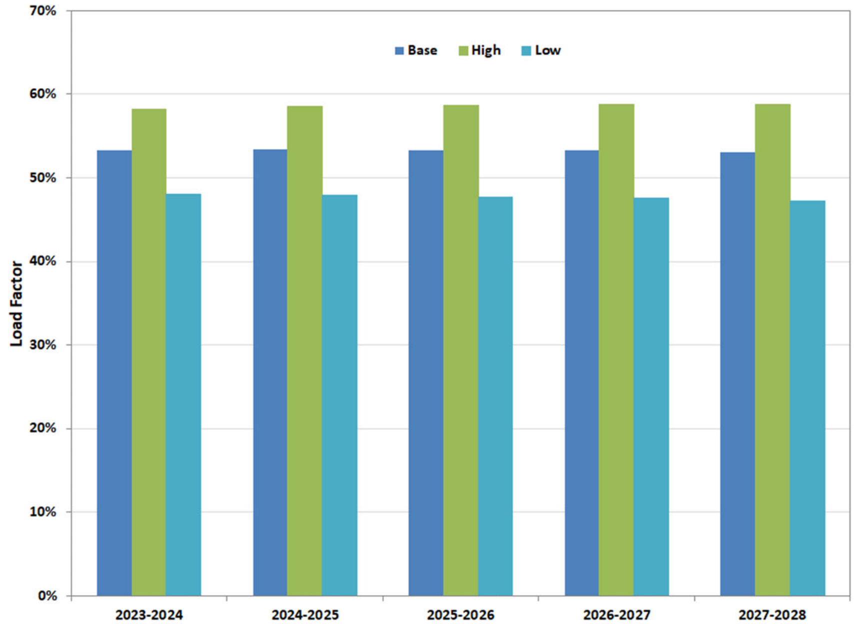


Figure 3-21: Sample Daily Load Shape, Spring Day in MidAmerican's Forecasts



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 47-59% 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

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

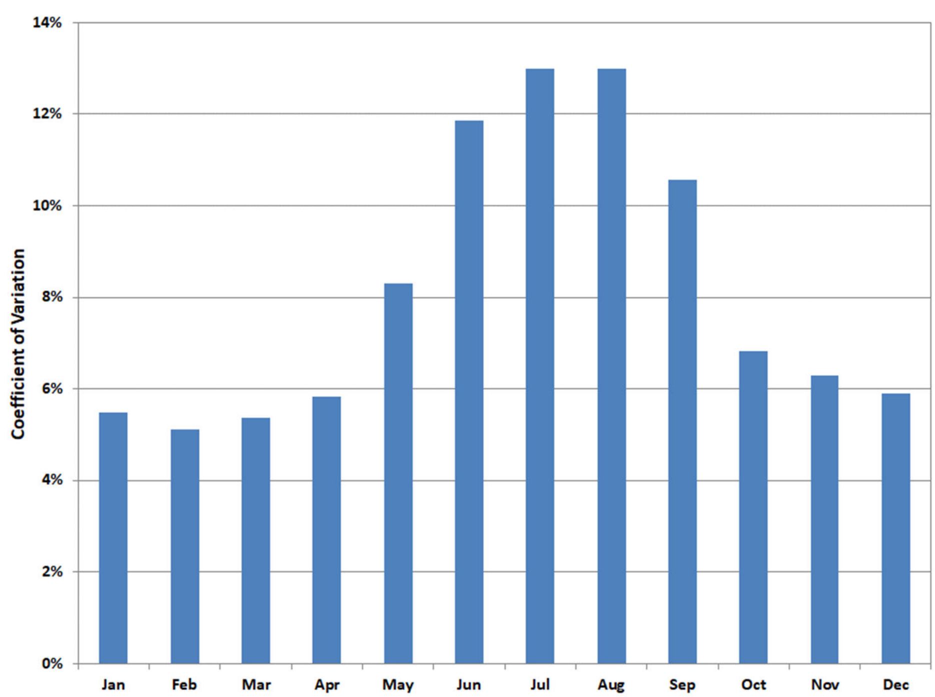
On a short-term basis, weather fluctuations are a key driver of the uncertainty in load forecasts, and in the daily variation of load forecasts around an average-day forecast. The discussion of high and low scenarios in Sections 3.2.2, 3.3.2, and 3.4.2 notes the way that Ameren Illinois, ComEd, and MidAmerican 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.

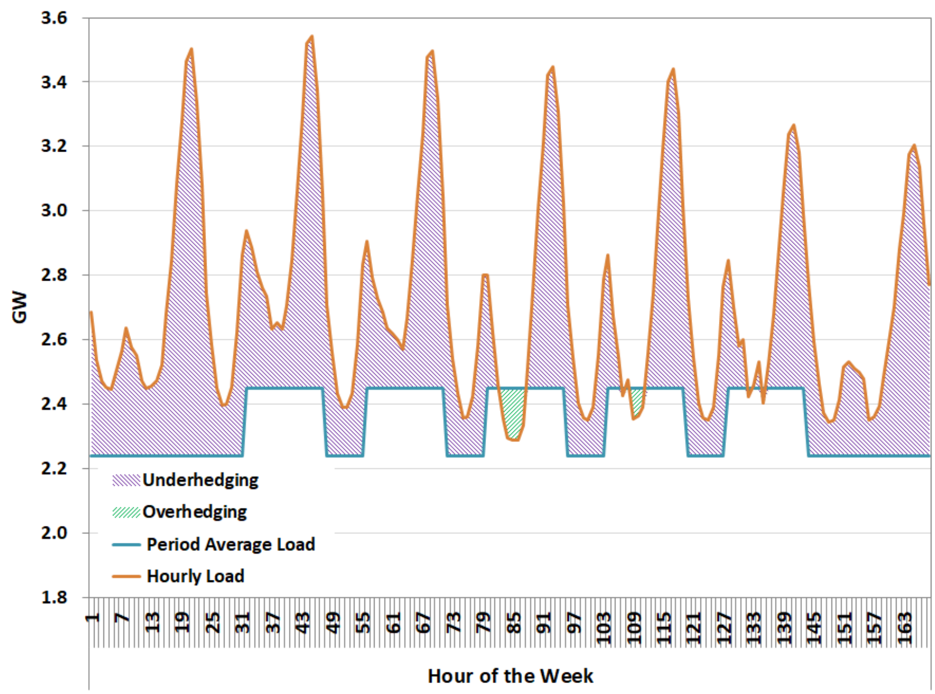
Figure 3-23 illustrates this disconnect by showing, for each month, the average historical "daily coefficient of variation" for peak period loads. This figure is based on historical ComEd loads from 2009 through 2020, normalized to the monthly base case forecasts in the first Delivery Year. To calculate 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 58% of potentially eligible retail customer load[102] will have switched away from Ameren Illinois default fixed price tariff service by the end of the 2022-2023 Delivery Year. This is lower than the 61% switching statistics in the July 2021 forecasts. Ameren expects that the amount of load supplied by ARES to decrease across the 2022 summer months due to the expiration of municipal aggregation contracts. [103] Ameren Illinois' current default service price is lower than comparable ARES prices for individual customers. ComEd projects that 32% of potentially-eligible retail load will have switched to ARES service by the end of the 2023-20204 Delivery Year, which represents a decrease from the 38% switching rate assumed in the July 2021 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

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

[103] Ameren Illinois's July 15, 2022 Load Forecast submitted to the IPA also contained three scenarios within its expected load forecast related to potential future changes in the level of switching due to municipal aggregation. These included a low scenario where no municipal aggregation load expiring in December 2022 or January 2023 comes back to Ameren Illinois default service; a mid scenario where half of that municipal aggregation load returns to Ameren Illinois default service (~1% change); and a high scenario where all of that municipal aggregation load returns to default service (~2% change). The Agency is including the mid scenario for this plan as reflected in Figure 3-4) and those assumptions will be used for the Fall 2022 procurement. For the Spring 2023 procurement the March 15, 2023 will be used for actual procurement volumes and will reflect what has actually occurred in terms of the continuation of municipal aggregation contracts.

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.[104] 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 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.[105] 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 or benefits to individual residential customers.[106] 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[107]

Utility Territory	Utility Price to Compare (¢/kWh)	Representative ARES Price (¢/kWh)
Ameren Illinois (Rate Zone I)	10.63	13.72
Ameren Illinois (Rate Zone II)	10.63	13.51
Ameren Illinois (Rate Zone III)	10.63	13.72
ComEd	11.04	11.07

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.

[104] For more information on choices offered by ARES, see the 2022 Annual Report of the ICC Office of Retail Market Development at https://icc.illinois.gov/downloads/public/icc-reports/2022%20ORMD%20Section%2020-110%20Report.pdf.

[105] 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.

[106] 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 2021 would pay approximately 28.5% more than if they were to take default supply service from the utility. ComEd retail customers would pay approximately 0.3% more. The utility prices are effective June 2022 through September 2022.

[107] Offers without an explicit premium renewable component. Monthly service fees and early termination fees are ignored.

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,[108] 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.

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 2022, there were 51 operational battery-based storage systems with a total capacity of 358.36 MW operating in PJM and 15 systems totaling 22.68 MW operating in MISO; the majority of these systems in terms of capacity were utility scale systems. Illinois was listed as having 12 projects with 144.06 MW in operation and under construction.[109] 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 2010 to 2021.[110] 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,[111] rebates for energy storage systems,[112] and

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

[109] U.S. Department of Energy Global Energy Storage Database, https://www.sandia.gov/ess-ssl/global-energy-storage-database/, downloaded July 25, 2022.

[110] - Battery Pack Prices Fall to an Average of $132/kWh, But Rising Commodity Prices Start to Bite. November 30, 2021

https://about.bnef.com/blog/battery-pack-prices-fall-to-an-average-of-132-kwh-but-rising-commodity-prices-start-to-bite

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

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

mandating a study of policies and programs that could support energy storage systems.[113] . The Agency will continue to monitor the development of the energy storage market in the coming years.

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. MidAmerican has incorporated the sales impacts into the retail kWh sales forecast and the peak demand forecast. The forecast includes a downturn in retail sales in 2023 through 2031.

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.[114] 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

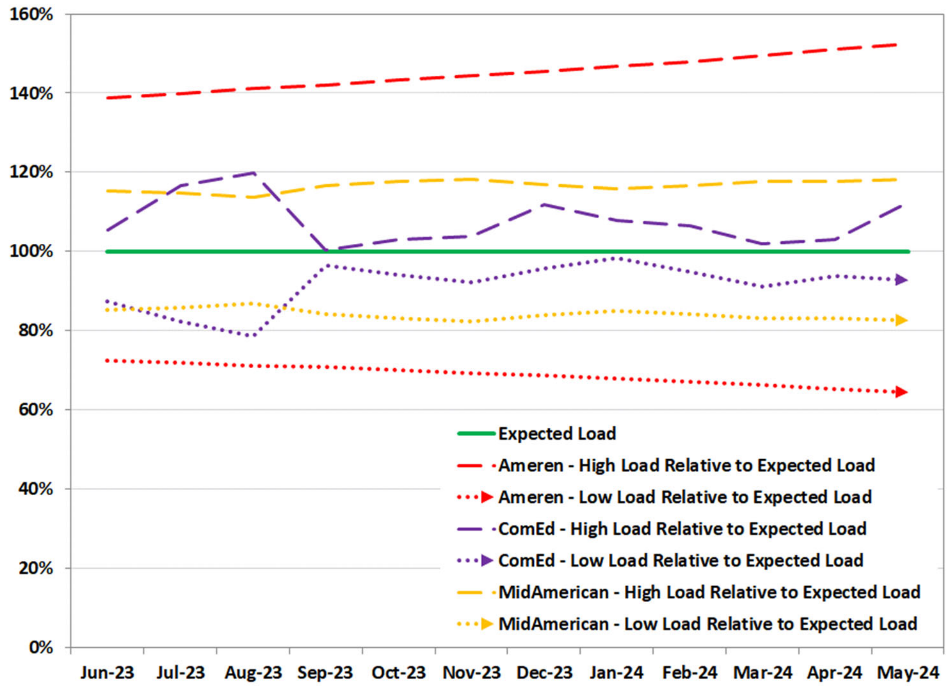
The high and low cases represent useful examples of potential load variability. Although they are primarily driven by variation in switching, Ameren Illinois correctly notes that this is the major uncertainty in its outlook. The switching variability, especially in Ameren Illinois' high and low forecasts, 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 69% and 145% of the base case forecast, respectively, during the 2023-2024 Delivery Year. Comparatively, for the same period, ComEd's low and high load forecasts are on average equal to 91% and 108% 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 117%, respectively. The reference case forecasts for retail switching were not changed in Mid American's high and low load forecasts.

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

[114] As discussed in Footnote 103, the Agency also adopts Ameren Illinois' mid scenario of switching related to municipal aggregation contained within the base case load forecast.

Figure 3-25: Comparison of Ameren Illinois, ComEd, and MidAmerican High and Low Load Forecasts for Delivery Year 2023-2024



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 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.[115] 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.[116]

The 2022 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 2023 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 2022 IPA 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%, while the remaining peak and off-peak requirements were targeted to be hedged at 100%. As a result of unusually high energy price volatility up to and on the bid date the Spring 2022 energy procurement event did not fill all of the targeted quantities for the 2022–2023 delivery year. Subsequently, in accordance with Section 16-111.5 of the IPA Act, a Supplemental Procurement event was held targeting the unfilled blocks remaining from the Spring 2022 procurement event for the months of June through September. A number of the energy blocks for ComEd MidAmerican targeted in the Supplemental Procurement were not filled and the energy associated with that unfilled volume will be procured by ComEd and MidAmerican in the RTO spot markets. The unfilled blocks for October 2022 through May 2023 have been added to the procurement targets for the Fall 2022 procurements.

As discussed in more detail in Section 6.9, the Agency conducted a stakeholder comment process starting in late June 2022 to gather input on electricity and capacity procurements in light of increasing energy and capacity prices and volatility.[117] Based on comments received from stakeholders in that process, the IPA considered a change for the Spring procurement events which would reduce the July and August on-peak hedging targets from 106% to 100%. Reducing the on-peak hedging targets from 106% to 100% may appear at first glance to afford a more accurate hedge; however, a 100% hedge would leave the utilities' supply portfolio exposed to significant price uncertainty, the result of shaping risk. Intra-day load and price spikes such as those typically observed in the on-peak periods of July and August produce a situation in which a 100% hedge would result in an under-hedged position. Carrying an under-hedged position during high-price months is a significant a concern. Maintaining the 106% hedging target during these peak periods mitigates 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

[115] See 2014 IPA Procurement Plan at 93.

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

[117] The Request for Feedback, comments received, and a recording of a workshop held on July 13, 2022 can be found at: https://ipa.illinois.gov/energy-procurement/plans-under-development.html.

determined that load shape and its correlation with prices adds approximately 6% to the average cost of energy supply. The IPA proposes to continue its current energy procurement strategy for July and August which involves procurement of on-peak hedges at 106% and off-peak at 100%, however the Agency will 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.

Additionally, the IPA proposes to 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 2023 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.[118]
- The February 2012 "Rate Stability" procurements mandated by Public Act 97-0616 for block energy products covering the period June 2013 through December 2017.[119]

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 2023 through May 2028, planning period, using the base case on-peak forecast described in Chapter 3.

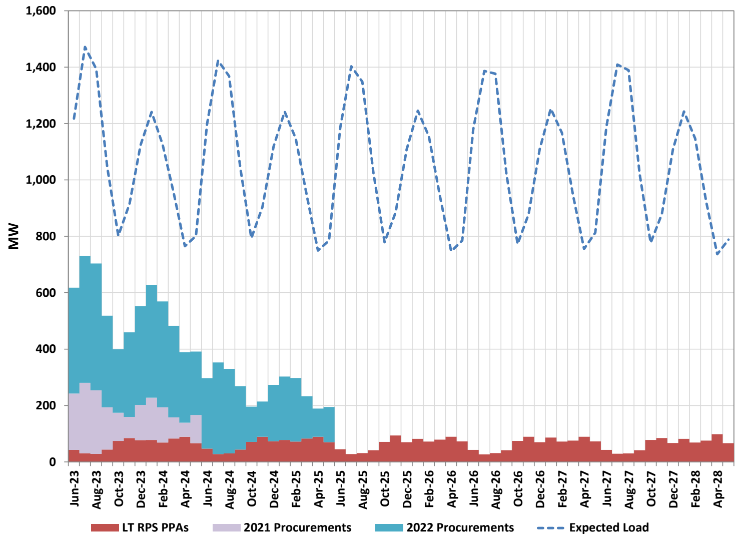
Ameren Illinois' existing supply portfolio, including long-term renewable energy resource contracts, is not sufficient to cover the projected load for the 2023-2024 Delivery Year. Additional energy supply will be required for the entire 5-year planning period. Approximately 58% of the Ameren Illinois eligible load has switched to ARES suppliers. 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.

[118] 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.

[119] 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 2023-May 2028 Period - Base Case Load Forecast

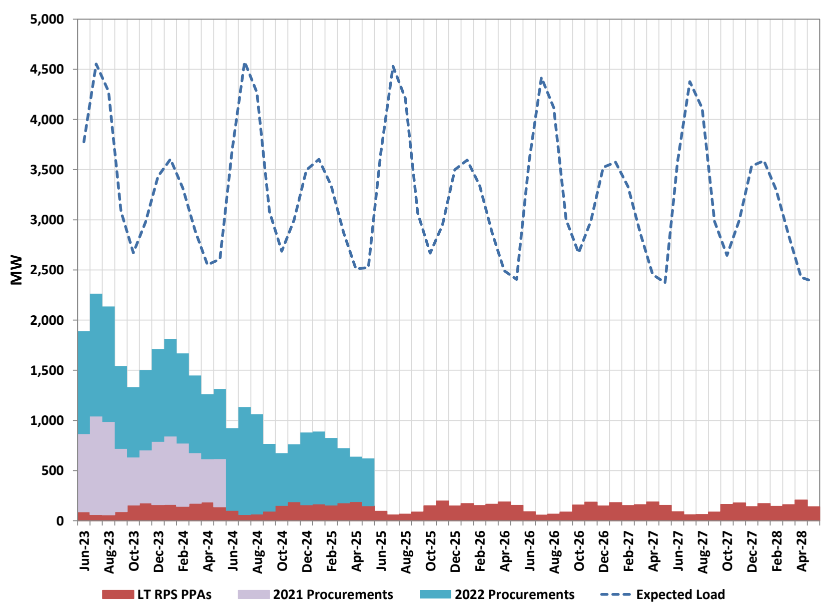


Under the base case load forecast scenario, the average supply gap for peak hours of the 2023-2024 Delivery Year is estimated to be 534 MW, the peak period average supply gap for the 2024-2025 Delivery Year is estimated to be 797 MW, and the average peak period supply gap for the 2025-2026 Delivery Year is estimated to be 986 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 2023-May 2028 planning period, using the base case load on-peak forecast described in Chapter 3. As of May 2022, 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 2023-May 2028 period - Base Case Load Forecast



As with Ameren Illinois, ComEd's current energy resources will not cover eligible retail customer load starting in June 2023. The average supply gap during peak hours for the 2023-2024 Delivery Year under the base case load forecast is estimated to be 1,655 MW. The average supply gap during peak hours for the 2024-2025 and 2025-2026 Delivery Years is estimated to be 2,480 MW and 3,139 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.[120]

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 and 2022 Plans. The IPA, for the 2022 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.

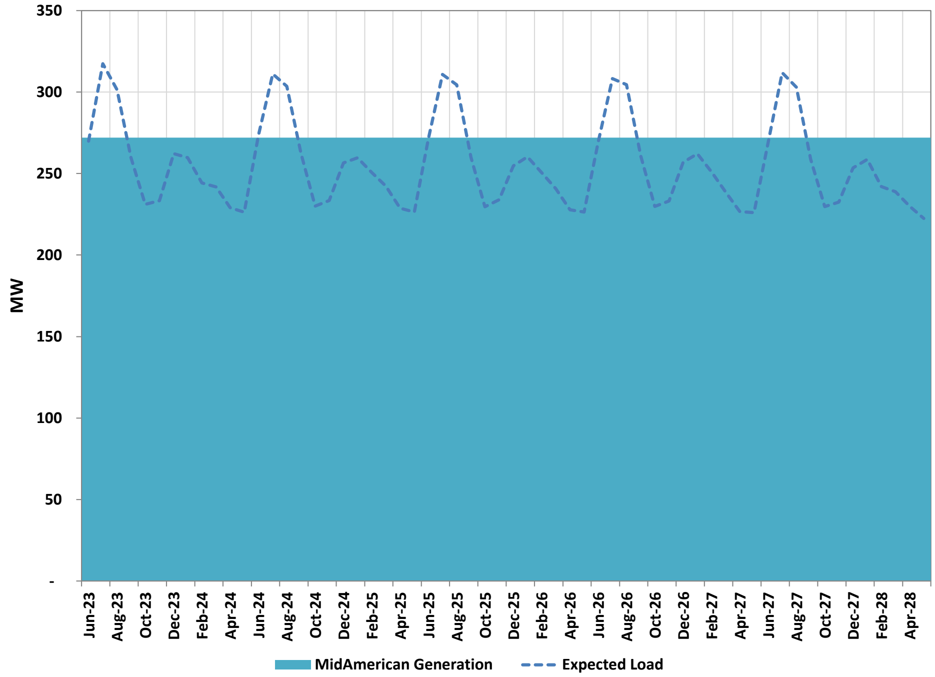
The supply capability that is determined is netted against the forecast of MidAmerican Illinois load to calculate the monthly on-peak and off-peak shortfalls which will be met with energy block purchases in the IPA procurements. In determining the amount of block energy products to be procured for MidAmerican, 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 2022 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 2023-2024 Delivery Year under the base case load forecast is estimated to be 16 MW. The average supply surplus during peak hours for the 2024-2025 Delivery Year is 15 MW and for the 2025-2026 Delivery Year the supply surplus is 16 MW.

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

Figure 4-3: MidAmerican's On-Peak Supply Gap - June 2023-May 2028 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.

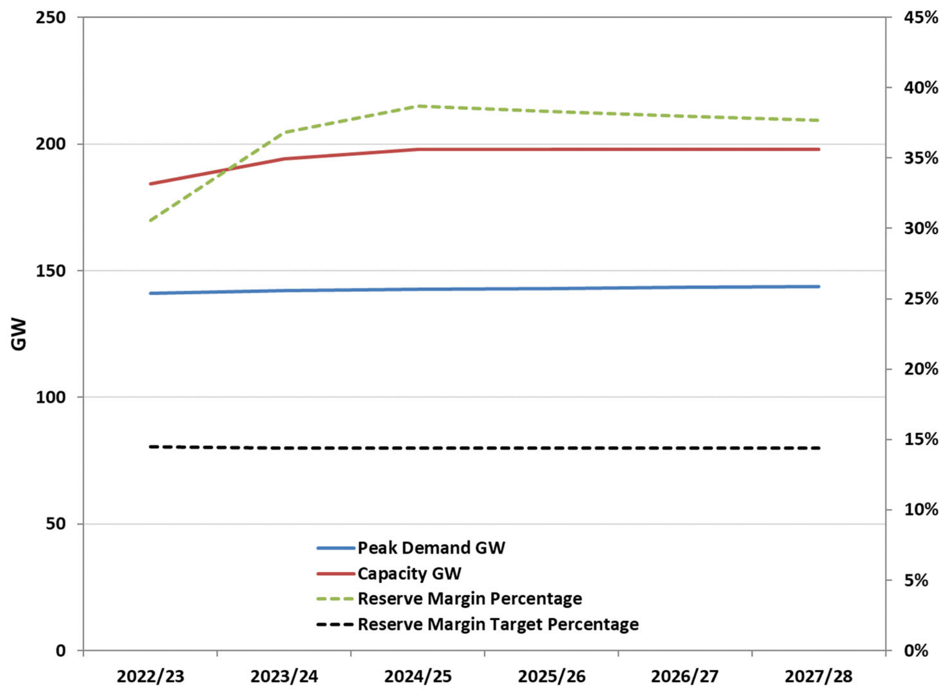
From the review and analysis of these entities' most recent resource adequacy documentation, it is apparent that, over the planning horizon, PJM will maintain adequate resources to meet the collective needs of customers in the PJM region. MISO, on the other hand, could be short of the resources necessary to meet the target reserve margin on a region-wide basis starting in the 2024-2025 timeframe. These conclusions are based on the expectation that the resources assumed to be available in these studies will be available when needed. However, as described in Section 5.2.2.2.3 this is not always be the case as evidenced by the results of MISO's 2022-2023 Planning Resource Auction ("PRA") which show a capacity deficit for the MISO North/Central region. As discussed further in Section 5.1.2 , the results of the 2022 MISO-OMS Survey indicate that MISO is projected to have a shortfall of 2.6 GW for the 2023-2024 Delivery Year which will primarily affect the MISO North/Central region, which includes Ameren Illinois in Zone 4.

5.1 Resource Adequacy Projections

5.1.1 PJM RTO

As shown in Figure 5-1, based upon the 2021 NERC Long-Term Reliability Assessment ("2021 NERC LTRA"), PJM is projected to have sufficient resources to meet load plus required reserve margins for the Delivery Years 2022-2023 to 2027-2028, with projected reserve margins above the 14.4% target reserve margin. For the 2022-2023 Delivery Year, the reserve margin is 16.1% above the target reserve margin and is 23.3% above the target reserve margin for the 2027-2028 Delivery Year.

Figure 5-1: PJM / NERC Projected Capacity Supply and Demand for Delivery Years 2022-2023 to 2027-2028



Source: 2021 NERC LTRA

5.1.2 MISO RTO

As shown in Figure 5-2, based upon the 2021 NERC LTRA, on a region-wide basis MISO is expected to have sufficient resources to meet load plus required reserve margin for the Delivery Years 2022-2023 to 2023-2024 with projected reserve margins above the 18.3% target reserve margin. However, in 2024-2025, MISO will have insufficient resources to meet load plus a target reserve margin. For the 2022-2023 Delivery Year, the reserve margin is approximately 5.8% above the target reserve margin, declining to 1.1% above the target reserve margin for the 2023-2024 Delivery Year, and finally dropping to 0.5% below the target reserve margin for the 2024-2025 Delivery Year. The 2021 NERC LTRA also notes that MISO could face the loss of over 13 GW of resource capacity from 2021 through 2024. These unconfirmed retirements include 10.5 GW of coal-fired generation and 2.4 GW of natural-gas-fired generation. A capacity shortfall of over 560 MW in 2024 would result if all of these unconfirmed retirements were to occur without additional new generation resources (on top of the 8 GW already in development for interconnection by 2024).

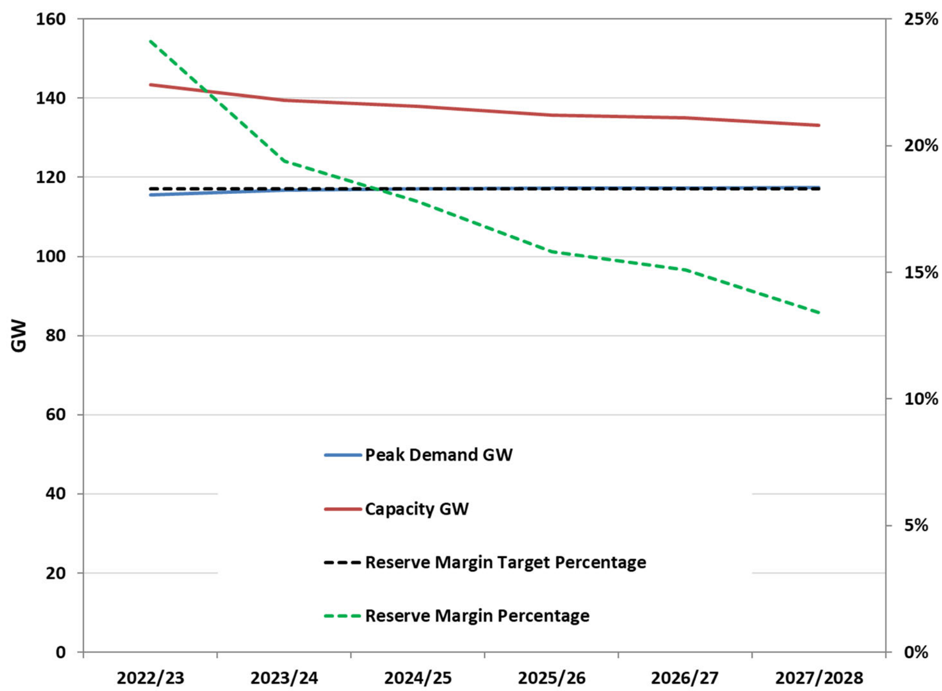
The observation in the 2021 NERC LTRA is consistent with statements made by MISO in the 2021 Transmission Expansion Plan ("2021 MTEP"). In the 2021 MTEP, MISO notes that, the MISO region will have adequate, but tighter, reserve margins for 2022, and continued action will be critical to ensure resource adequacy in the future.[121] While the IPA acknowledges the findings of these region-wide long-term assessments, the IPA also notes that the results of these findings are based on the expectation that the resources assumed in the assessments will be available when needed. However, as described in Section 5.2.2.2.3 this may not always be the case as evidenced by the results of MISO's 2022-2023 Planning Resource Auction, which show a capacity

[121] See MISO MTEP at https://cdn.misoenergy.org/MTEP21%20Full%20Report%20including%20Executive%20Summary611674.pdf , at page 24.

deficit for the MISO North/Central region. Further, the results of the 2022 MISO-OMS Survey indicate that MISO is projected to have a shortfall of 2.6 GW for the 2023-2024 Delivery Year that will primarily affect the MISO North/Central region which includes Zone 4.[122] However, the same survey also notes that depending on market responses to the results of the 2022-2023 MISO PRA, the projected surplus could be as much as 2.4 GW.[123]

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

Figure 5-2: MISO / NERC Projected Capacity Supply and Demand for the Delivery Years 2022-2023 to 2027-2028



Source: 2021 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

[122] https://cdn.misoenergy.org/20220610%20OMS-MISO%20Survey%20Results%20Workshop%20Presentation625148.pdf

[123] The results of the 2022-2023 MISO PRA are described in Section 5.2.2.2.3.

construct, which established a Capacity Performance product.[124] RPM is a forward capacity auction through which generators offer capacity to serve the obligations of load-serving entities. 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.[125] In addition to the BRAs, up to three incremental auctions are held, at intervals of 20, 10, 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 short-term resource procurement.[126] 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.

Just prior to the beginning of each Delivery Year, the Final Zonal Net Load Price, which is the price paid by LSEs for capacity procured as part of the RPM, is calculated. 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").[127]

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 and 2023-2024[128]

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[124] 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, and 2021-2022 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.

[125] 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.

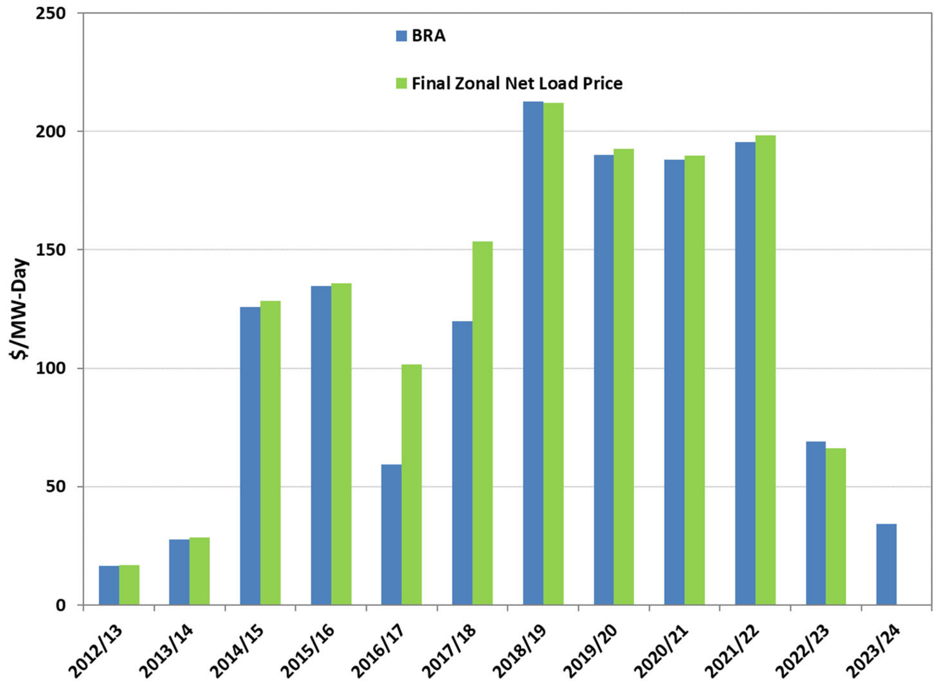
[126] Deferred short-term resource procurement only applies prior to the 2018-2019 Delivery Year.

[127] 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.

[128] In 2017-2018, 2018-2019, 2019-2020, 2020-2021, 2021-2022, 2022-2023, and 2023-2024 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, the results showed that the zone was a constrained LDA. Binding constraints therefore also contributed to the higher clearing price although 2022-2023 and 2023-2024 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.

Figure 5-3 shows little variation between the BRA clearing price and the Final Zonal Net Load Price for the 2018-2019, 2019-2020, 2020-2021, 2021-2022, and 2022-2023 Delivery Years which, as noted before, is consistent with procuring the majority of the capacity during the BRA.

Figure 5-3: PJM (ComEd Zone) Capacity Price for Delivery Years 2012-2013 to 2022-2023[129]



As explained in more detail in the 2020 Electricity Procurement Plan,[130] FERC has issued a number of orders that will significantly change PJM's RPM in the future. As noted in the 2020 Electricity Procurement Plan, in an order[131] issued on June 29, 2018, FERC ruled 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[132] 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.[133]

[129] 2022-2023 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.

[130] See pages 46-48 of 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

[131] 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.

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

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

On December 19, 2019, FERC issued an Order in FERC Docket No. EL18-178-000. In its Order, FERC 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 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.[134] In its filing, PJM submitted revisions to their tariff to 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,[135] PJM proposed that, in the event that legislation directly applicable to new elections of the Fixed Resource Requirement Alternative[136] 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 addressing requests for rehearing of its December 19, 2019 Order.[137] In that 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 addressing the issues raised in FERC's Order which include, but are 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.[138]

On October 15, 2020, FERC issued an Order 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.[139] 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.[140]

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[134] 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.

[135] 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.

[136] 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.

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

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

[139] 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.

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

On November 12, 2020 FERC approved PJM's E&AS compliance filing,[141] 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 long established self-supply business models, while adequately mitigating buyer-side market power".[142] 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 has 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 wants 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.[143] 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.[144] PJM filed their proposal with FERC on July 30, 2021.[145] PJM's proposal will replace the current MOPR provisions in the PJM Tariff. The PJM proposal, which is to be effective starting with the 2023-2024 delivery year, is 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 will be applied to generation capacity resources that exercise Buyer-Side Market Power[146] and generation capacity resources that receive Conditioned State Support.[147] PJM will 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.[148]

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

142 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

143 https://www.pjm.com/committees-and-groups/cifp-mopr.

144 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.

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

146 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.

147 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.

148 Notice of Filing Taking Effect by Operation of Law, Docket No. ER21-2852-000, September 29, 2021.

5.2.2 Overview of MISO Planning Resource Auction

The MISO Resource Adequacy Construct, specified in Module E-1 of its Tariff,[149] 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")[150] 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.[151] On February 28, 2018, FERC issued an order accepting MISO's filing.[152] MISO's Independent Market Monitor ("IMM"), however, 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."[153] 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."[154]

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.[155] FERC's Staff issued a Deficiency Letter[156] to MISO on May 15, 2018, to which MISO responded on June 5, 2018.[157] FERC issued an Order on August 2, 2018 rejecting MISO's proposed tariff revisions but providing some guidance for a revised proposal.[158] On August 31, 2018 MISO submitted a revised proposal.[159] On October 31, 2018, FERC issued an order accepting MISO's filing.[160]

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 2022 MISO PRA was the tenth auction administered by MISO.

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[149] 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.

[150] 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.

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

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

[153] Id. at 6.

[154] Id. at 6.

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

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

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

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

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

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

5.2.2.1 Proposed Changes to MISO's Resource Adequacy Construct

Proposed Seasonal Resource Adequacy Construct

In a filing to FERC made on November 30, 2021, MISO proposed revisions to its Tariff to establish Resource Adequacy Requirements on a seasonal basis for each of the Summer, Fall, Winter and Spring Seasons, and to implement an availability-based Seasonal Accredited Capacity ("SAC") methodology for resources participating in MISO's annual PRA.[161]

In the filing, MISO explains that the MISO region is experiencing significant shifts in generation resource retirements, increased reliance on intermittent resources, significant weather events with correlated generator outages, and declining excess reserve margins. MISO further explains that the current Resource Adequacy construct, which focuses on the procurement of capacity for an entire Planning Year to meet demand during one peak day of the summer season was not designed to address the trends currently facing the MISO region, noting that reliability risks associated with Resource Adequacy have shifted from "summer only" to a year-round concern. Since 2016, MISO has experienced 40 maximum generation declarations[162] (including alerts, warnings, and events) with more than 60% occurring outside of the summer months.

To address these issues, MISO proposes the establishment of a seasonal Resource Adequacy construct coupled with availability-based accreditation for certain Planning Resources; and a Minimum Capacity Obligation that promotes securing capacity well in advance of the PRA. MISO intends to transition from the current 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. Under the proposed construct MISO will establish PRMRs for all market participants representing load serving entities on a seasonal basis. MISO will also develop seasonal local reliability requirements, seasonal LCRs, seasonal capacity import limits, and seasonal capacity export limits. MISO will then conduct the PRA and establish an Auction Clearing Price for each Local Resource Zone ("LRZ") for each season. The PRA will be conducted one time per year, in the spring before the applicable Planning Year, but will clear the requirements for each season.

With regard to resource accreditation, MISO seeks to assure that planning resources are available during the times they are needed the most by aligning resource accreditation with availability during the highest risk periods in each season, referred to a Resource Adequacy Hours ("RA Hours"). To accomplish this in a seasonal construct, MISO proposes to determine the SAC for certain classes of resources. The affected resources are Demand Response Resources and Capacity Resources that are Generation Resources (collectively "Schedule 53 Resources"). Resources, which are designated as Schedule 53 Resources will be subject to the proposed 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) will continue to have their accreditation determined generally as it is done today, with appropriate adjustments made to convert their accreditation to a seasonal basis.[163]

MISO is proposing a tiered weighting structure to determine individual resource accreditation by season based on each resource's real-time offered availability, accounting for coordinated planned outages. The first tier will determine each resource's real time offered availability during non-tight operating condition hours, and the second tier will determine each resource's real-time offered availability during hours with the tightest operating conditions, including declared MaxGens. The second tier will be more heavily weighted at 80% so that the majority of a resource's accreditation will be based on its availability during times of need. MISO notes that actual historic resource availability and performance during times of highest need is a useful and

[161] Docket No. ER22-495-000, November 30, 2021.

[162] Also referred to as "MaxGens".

[163] The current resource 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 utilized 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).

reasonable indicator of what to expect in the future. Relying on installed capacity, adjusted for forced outages and reflecting average availability throughout the year, no longer provides an accurate expectation of availability, as proven by recent emergency events, especially those driven by extreme weather.

MISO is seeking an effective date of September 1, 2022 for the Seasonal Resource Adequacy Construct to allow for enough planning before the 2023-2024 Planning Year. As of the release of this draft 2023 Electricity Procurement Plan, FERC has not yet released an Order on the Seasonal Resource Adequacy Construct.

Minimum Capacity Obligation

On the same date that MISO filed the Seasonal Resource Adequacy Construct filing, MISO also made a separate filing to establish a Minimum Capacity Obligation ("MCO") on market participants participating in MISO's PRA. MISO notes that the MCO is intended to encourage all market participants representing LSEs, regardless of regulatory structure, to perform prudent resource planning and to ensure an LSE does not rely solely on the PRA to procure all necessary capacity to meet its RAR. MISO's MCO proposal establishes a minimum level of Zonal Resource Credits ("ZRCs") LSEs will be obligated to procure ahead of the PRA, either through ownership or bilateral contracts. It establishes a threshold of 50% percent of an LSE's PRMR, with a 50 MW de minimis exemption164, which must be procured ahead of the PRA or be subject to non-compliance charges. MISO notes that these provisions enforce a fundamental assumption that all LSEs are planning appropriately to support long-term Resource Adequacy in the MISO Region.

Market Participants representing LSEs that fail to satisfy the MCO will incur a significant non-compliance charge (the "MCO Non-Compliance Charge") based on the shortfall. The MCO Non-Compliance Charge is set at 1.5 times the daily Cost of New Entry ("CONE"). The charge will be a one-time charge assessed immediately after the PRA. MISO notes that imposing an MCO will reduce the potential for capacity shortfalls in future PRAs. MISO believes that by imposing charges on market participants representing LSEs that do not procure a minimum proportion of their capacity obligation prior to the PRA, the MCO rule will incent LSEs to contract forward for at least a portion of their capacity obligation, further noting that this incentive will be particularly strong when LSEs recognize the potential for a tightening of the capacity supply-demand balance before the PRA.

MISO proposes to apply the MCO on a region-wide basis initially, commencing with the 2023-2024 Planning Year. MISO notes that implementing the MCO on a region-wide basis gives LSEs an opportunity to become accustomed to complying with the obligation and to take advantage of available capacity across the region while still respecting the Local Clearing Requirements for each zone. MISO plans to transition to a sub-regional application of the MCO starting in the 2025-2026 Planning Year. After this transition, the MCO will be applied separately to two planning areas --- the First Planning Area (North/Central region) and the Second Planning Area (South region), respectively. Prior to the transition MISO will make another filing with FERC proving details on the sub-regional MCO and the planning areas.

It is the IPA's understanding that the MCO will be applied to LSEs serving Zone 4, so for example, Ameren Illinois which serves eligible retail customers will be assessed the MCO for the load it serves and the alternative retail suppliers ("ARES") which also serve load in Zone 4 will be assessed the MCO for their share of the load. The IPA notes that the MCO proposal does not take into account the characteristics of Illinois retail choice which allows switching among various supply options including ARES and Ameren default supply. This creates a problem if load changes during the delivery year after the MCO has already been set. The IPA also notes that the move to a Seasonal Resource Adequacy Construct, if approved by FERC, would require an update to the current IPA procurement approach in that there would now be a need for the IPA to conduct bilateral procurements for the four seasons as required by the MISO Tariff.[165] The IPA also notes that it has been procuring 50% of the

[164] The de minimis exemption will help address any potential undue burden the MCO might otherwise impose on smaller LSEs. This *de minimis* threshold is necessary to avoid placing an overly burdensome MCO on small LSEs that may not be well positioned to meet their obligation through the bilateral markets.

[165] Capacity contracts used in 2021 and 2022 include provisions to update the delivery obligations should FERC approval a shift to a seasonal construct. In particular the contracts note that in the event that MISO receives FERC approval on July 12, 2022 or later to implement any change to its resource adequacy construct, which includes a seasonal component, the Buyer and Seller shall agree to an amendment to the contract that addresses the change to the MISO resource adequacy construct.

capacity requirements for Ameren Illinois eligible retail customers in its bilateral procurements and therefore Ameren Illinois would be able to comply with the MISO requirements if the MCO is approved.

5.2.2.2 Review of IPA Capacity Procurement Results and MISO PRA, Overview of the Results of the MISO PRA, and Analysis of the Results of the 2022-2023 PRA

5.2.2.2.1 Review of IPA Capacity Procurement Results and MISO PRA

Since 2016-2017, the IPA's capacity hedging strategy has involved procuring a certain amount through the IPA's bilateral procurements and the remainder in the MISO PRA. Table 5-1 and Table 5-2 show by delivery year, the price and amount of capacity that was procured in the IPA's bilateral procurements and in the MISO PRA.

Table 5-1: Capacity Procured in the IPA's Bilateral Procurements

Date Held	Delivery Year	Price ($/MW-Day)	Amount Procured (%)
N/A	2015-2016	N/A	N/A
Fall 2015	2016-2017	138.12	50%
Fall 2016	2017-2018	143.20	75%
Fall 2016	2018-2019	137.25	25%
Fall 2017	2018-2019	23.26	50%
Spring 2018	2019-2020	$28.11	13%
Fall 2018	2019-2020	$27.51	37%
Spring 2019	2020-2021	$24.65	6%
Spring 2019	2021-2022	$27.99	3%
Fall 2019	2020-2021	$23.74	21%
Fall 2019	2021-2022	$27.75	8%
Spring 2020	2021-2022	$17.23	23%
Spring 2020	2022-2023	$25.26	12%
Fall 2020	2021-2022	$19.59	16%
Fall 2020	2022-2023	$26.90	15%
Spring 2021	2022-2023	$29.50	3%
Fall 2021	2022-2023	$28.92	21%

Table 5-2: Capacity Procured in the IPA's Bilateral Procurements

Date Held	Delivery Year	Price ($/MW-Day)	Amount Procured (%)
Apr-15	2015-2016	$150.00	100%
Apr-16	2016-2017	$72.00	50%
Apr-17	2017-2018	$1.50	25%
Apr-18	2018-2019	$10.00	25%
Apr-19	2019-2020	$2.99	50%
Apr-20	2020-2021	$5.00	73%
Apr-21	2021-2022	$5.00	50%
Apr-22	2022-2023	$236.66	50%

Table 5-1 and Table 5-2 are summarized in the table below.

Table 5-3: Capacity Procured Summary

	Amount Procured (%)	
	IPA's Procurements	MISO PRA
2015-2016	0%	100%
2016-2017	50%	50%
2017-2018	75%	25%
2018-2019	75%	25%
2019-2020	50%	50%
2020-2021	27%	73%
2021-2022	50%	50%
2022-2023	50%	50%

Table 5-4 and Table 5-5 provide a summary of the weighted average cost of capacity procured in the IPA's procurements, the cost in the MISO PRA, as well as the overall weighted average cost of capacity for Illinois eligible retail customers which is the weighted average of capacity procured in the IPA's procurements and capacity procured in the MISO PRA.

Table 5-4: MISO PRA vs IPA Bilateral Procurement Results

	2015-2016	2016-2017	2017-2018	2018-2019	2019-2020	2020-2021	2021-2022	2022-2023
IPA Procurement Price ($/MW-Day)	N/A	$138.12	$143.20	$61.26	$27.66	$23.94	$20.34	$27.50
MISO PRA Price ($/MW-Day)	$150.00	$72.00	$1.50	$10.00	$2.99	$5.00	$5.00	$236.66
Weighted Average Price ($/MW-Day)	$150.00	$105.06	$107.78	$48.44	$15.33	$10.16	$12.67	$132.08

Figure 5-4: MISO PRA vs IPA Bilateral Procurement Results

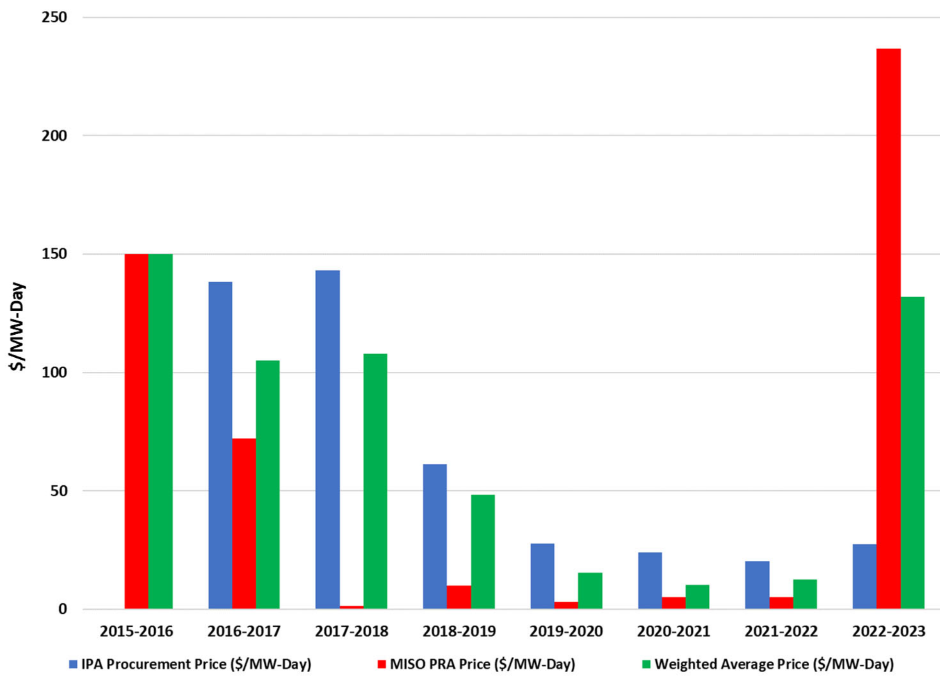
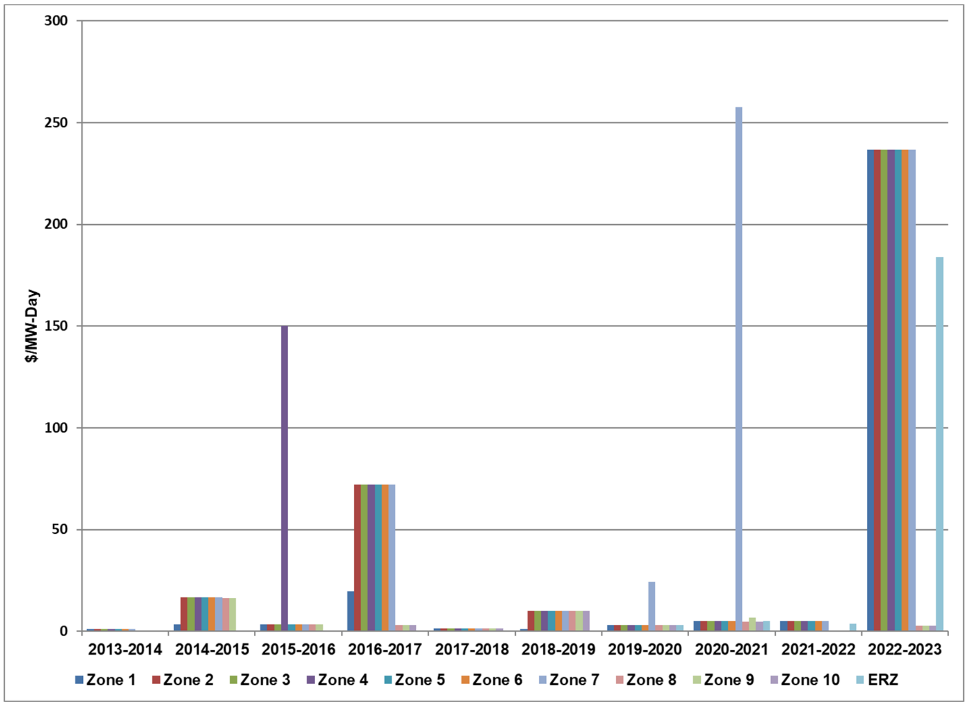


Table 5-4 and Figure 5-4 show that the IPA's capacity hedging strategy has had a positive impact on the overall price paid by Ameren Illinois eligible retail customers. While the price in the MISO PRA has shown considerable volatility, from 2016-2017 through 2021-2022 that price was lower than the weighted average price from the IPA's bilateral procurements and the overall weighted price benefitted Ameren Illinois eligible retail customers. Also, for the 2022-2023 Delivery Year the weighted average price from the IPA's bilateral procurements, at $27.50/MW-Day was lower than the MISO PRA price at $236.66/MW-Day. The overall weighted price of $132.08/MW-Day is 44% lower than the MISO PRA price which shows the benefit of the IPA's hedging strategy. This price is actually lower than the weighted average price from the IPA's bilateral procurements in 2016-2017 and 2017-2018.

5.2.2.2.2 Overview of Results of the MISO PRA

Figure 5-5 below shows the results of the MISO PRA since its inception.

Figure 5-5: MISO PRA Results



As shown in Figure 3-1, and explained in detail in the 2019 Electricity Procurement Plan,[166] 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 $150/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 2016 Electricity Procurement Plan.[167] 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. An analysis of the results for Zones 1-7 are presented in the next section.

5.2.2.2.3 Analysis of the Results of the 2022-2023 PRA

In the 2022 Electricity Procurement Plan the IPA presented an analysis of the ability of Zone 4 (Ameren Illinois) to meet its LCR. The analysis showed that, under all tested scenarios, Zone 4 will be able to meet its LCR through 2026-2027, the study period. The impact of the shortage of resources to meet the LCR was evidenced in the results of the 2020-2021 PRA. In that auction, Zone 7(Michigan) cleared at the cost of new entry, a high price relative to the other zones, due to insufficient capacity to meet the LCR. The IPA also noted that in the 2015-2016 PRA, Zone 4 cleared at a high price due to the need to meet the LCR. However, in that case the high price was not due to a shortage of resources to meet the LCR but was due to a bidder submitting an extraordinarily high offer, and because that offer was needed to meet the LCR, it set the clearing price for Zone 4. The IPA's analysis was focused on assessing whether there were sufficient planning resources to meet the Zone 4 LCR,

[166] See IPA's Final 2019 Electricity Procurement Plan, Section 5.2.2, pages 54-55.

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

and therefore prevent what occurred in Zone 7 taking place in Zone 4. However, based on the results of the 2022-2023 PRA, failure to meet the LCR is not the only potential trigger of a high clearing price in Zone 4; a regional shortage of resources can also trigger a similar outcome.

The results of MISO's 2022-23 PRA indicate a capacity shortfall for the MISO North/Central Region which includes Zones 1-7, resulting in those zones clearing at the CONE at $236.66/MW-Day.

Consistent with Module E-1 of the MISO Tariff, MISO establishes Sub-Regional Resource Zones ("SRRZ") for which the multi- zone optimized auction includes the marginal cost of binding Sub-Regional limits.[168] An SRRZ is a zone, comprised of an LRZ or combination of two or more LRZs, to administer constraints in accordance with applicable seams agreements, coordination agreements, or transmission service agreements. Currently, MISO has two SRRZs: MISO South defined as LRZs 8, 9 and 10 and MISO North/Central defined as LRZs 1-7. These SRRZs are a result of the settlement agreement between MISO, Southwest Power Pool, and the other Joint Parties. This agreement established regional transfer limits that limit the amount of the total transfer between the two SRRZs in the PRA. [169] For the 2022-2023 PRA MISO set the South to North limit at 1,900 MW.[170]

In a conference call held on April 15, 2022 to discuss the results of the 2022-2023 PRA, MISO explained that the high price for Zones 1-7 was the result of a regional shortage of capacity, based on the PRA clearing dynamics. MISO further noted that while the MISO-OMS survey projected a small surplus for Delivery Year 2022-2023, that surplus was eroded by (i) an increased load forecast, (ii) less capacity entering the auction as a result of retirements, and (iii) the decreased accredited capacity of new resources.[171] The increased load forecast resulted in an increase in the PRMR of 1.4 GW for 2022-2023, and combined with the reduced generation capacity this resulted in an overall shortfall of capacity. While the installed capacity has increased in the last five years, accredited capacity has decreased due to thermal generation retirements and the increasing transition to renewables.

MISO further explained that the objective function of the PRA is multi-zonal, not zonal *i.e.* its goal is to optimize the multi-zones in a given region to ensure clearing at the lowest price. In this case, for the 2022-2023 PRA the North/Central region which comprises of Zones 1-7 experienced a 1,230 MW shortfall capacity in meeting the region's PRMR. MISO noted that while LCR is assessed on a zonal basis, the PRMR is assessed only on a regional basis. All zones, including Zone 4, met their LCR requirements. Despite importing 3,225 MW (1,900 MW from the South and1,325 MW from External Zones, the North/Central region still came up short in meeting its PRMR requirements. As established by the MISO Tariff, when there is a shortfall in meeting the PRMR, the clearing price is set at the CONE.[172] In this case because the shortage was regional, and consistent with the Tariff's objective of the multi-zone optimization methodology, the PRA algorithm looks at the lowest CONE of the affected zones, which in this case was the CONE for Zone 3.[173] The price for Zones 1-7 therefore cleared at $236.66, the CONE for Zone 3.

On May 25, 2022, MISO provided additional explanation of the 2022-2023 PRA results to the Resource Adequacy Sub-Committee. In that presentation,[174] MISO noted that twenty one generation resources in the North/Central region, totaling 3.4 GW, which were categorized as either high or low certainty in the MISO-OMS survey ended up not participating in the 2022-2023 PRA. Ten of these resources totaling 1.8 GW were in the MISO-OMS survey results with a high certainty to be available and all 10 were granted exclusions from

[168] See MISO presentation at: https://cdn.misoenergy.org/20220420%20RASC%20Item%2004b%20PRA%20Results%20Supplemental624128.pdf

[169] See MISO Resource Adequacy Business Practice Manual at: https://cdn.misoenergy.org//BPM%20011%20-%20Resource%20Adequacy110405.zip

[170] See MISO presentation at: https://cdn.misoenergy.org/20220420%20RASC%20Item%2004b%20PRA%20Results%20Supplemental624128.pdf

[171] See MISO PRA results presentation at: https://cdn.misoenergy.org/2022%20PRA%20Results624053.pdf

[172] See MISO Tariff Module E-1 at: https://docs.misoenergy.org/legalcontent/Module_E-1_-_Resource_Adequacy.pdf

[173] Id.

[174] See MISO presentation at: https://cdn.misoenergy.org/20220525%20RASC%20Item%2004d%20PRA%20Detail624732.pdf

participating in the 2022-2023 PRA by the MISO Independent Market Monitor ("IMM"). Eleven of these resources totaling 1.5 GW were in the MISO-OMS survey results with a low certainty to be available and all 11 were granted exclusions from participating in the 2022-2023 PRA by the IMM. In the same presentation MISO also noted that in the North/Central region there were 3.2 GW net less capacity in the 2022-2023 PRA versus the 2021-2022 PRA.

The results of the 2022-2023 PRA highlight that many operational factors in the PRA construct produce a significant risk management challenge. While the IPA can analyze resource adequacy conditions in Zone 4 and make a reasonable estimate of how available capacity stacks up against the LCR, as evidenced by the analysis that was conducted in the 2022 Electricity Procurement Plan,[175] the PRA construct has inherent risks that are difficult to analyze and consequently difficult to hedge against. As noted above, in the PRA, PRMR is not assessed on a zonal basis, only on a regional basis. This means that in the PRA clearing engine a shortage of PRMR in Zone 4 does not count as a "shortage" to the zone but to the region for capacity clearing price purposes.[176] On the other hand, a shortage of LCR in Zone 4 counts as a shortage of capacity to the zone for capacity clearing price purposes. The issue of potential regional shortages brings into question the level of contribution that the MISO PRA should have on resource adequacy in Zone 4. The IPA's hedging strategy for Zone 4 capacity is therefore of paramount importance as discussed below.

While the results of the 2022-2023 PRA in Zones 1-7 are attributable to a regional shortage of capacity as noted above, another issue for consideration is whether there is a structural deficiency with the MISO PRA. The IPA notes that the MISO IMM has been critical of the structure of the PRA and has advocated for the implementation of a sloped demand curve as far back as the 2013 State of the Market Report. In the 2013 State of the Market Report the IMM noted that "The implication of the vertical demand curve is that the last MW of capacity needed to satisfy the minimum requirement has a value equal to the deficiency price, while the first MW of surplus has no value. This is not true in reality—each unit of surplus capacity will improve reliability and lower energy and ancillary services costs for consumers …."[177] In the same report the IMM further noted "A sloped demand curve would produce more stable and predictable pricing, which would increase the capacity market's effectiveness in providing incentives to govern investment and retirement decisions … The need for a sloped demand curve may become particularly acute as planning reserve margins decline toward the minimum requirement level with the likely retirement of significant amounts of coal-fired capacity in MISO…"[178] In the 2020 State of the Market Report the IMM continues to recommend the implementation of a sloped demand curve in the PRA noting as follows "The most significant design flaw relates to how the demand for capacity is represented. Demand in the PRA is modeled as a single requirement (and single zonal requirements), and a deficiency price prevails if the market is short (as occurred in Zone 7 in the 2020-2021 auction). This establishes a "vertical demand curve" for capacity, which implicitly values incremental capacity above the minimum requirement at zero. This is inconsistent with its true reliability value and results in inefficient capacity market outcomes."[179] While the IPA takes no position on whether a sloped demand curve should be implemented in the PRA, the IPA notes that to the extent such an implementation would have a beneficial impact on PRA outcomes in Zone 4 and reduce the volatility of prices in the zone, thereby having a positive impact on Illinois customers, the IPA believes stakeholders in MISO should revisit the IMM's recommendations.

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[175] See Section

[176] In the 2022 Electricity Procurement Plan the IPA notes that from 2014-2015 through 2021-2022, Zone 4 has on average averaged imported 1,115 MW from neighboring zones. Zone 4, even when its available UCAP was greater than its PRMR, still imported from neighboring zones based on clearing dynamics. See 2022 Electricity Plan at page 60.

[177] See https://www.potomaceconomics.com/wp-content/uploads/2013/06/2013-State-of-the-Market-Analytical-Appendix.pdf at page 18.

[178] Id at page 19.

[179] See https://www.potomaceconomics.com/wp-content/uploads/2021/05/2020-MISO-SOM_Report_Body_Compiled_Final_rev-6-1-21.pdf at page viii.

5.2.2.2.4 Impact of the Results of the 2022-2023 PRA on the IPA's Hedging Strategy

The regional shortage of capacity in Zones 1-7 and the resultant spike in the PRA's clearing price in those zones shows the continued volatility of the MISO PRA, which begs the question of what if any changes should be made to the IPA's capacity hedging strategy—which has traditionally reflected purchasing 50% of the capacity requirements in the IPA's bilateral procurements and 50% in the MISO PRA. The IPA notes that, as described above, if MISO's proposal to implement an MCO is approved by FERC, the IPA's hedging strategy will no longer be a preference but a requirement. The MCO will require that all load serving entities procure 50% of their capacity requirements in bilateral procurements and the remainder in the MISO PRA.

After the 2015-2016 MISO PRA price spike, the IPA moved to a 50%/50% hedging strategy. The MISO price in 2016-2017 dropped to $72/MW-Day, 52% lower than the 2015-2016 price. After 2016-2017 the IPA adopted a 75%/25% hedging strategy for the 2017-2018 and 2018-2019 delivery years. The MISO PRA price for those years was $1.50/MW-Day and $10/MW-Day respectively. In 2020-2021, even though the hedging strategy was 50%/50% the IPA was only able to procure 27% from its procurements with the remaining 73% procured from the MISO PRA. For that delivery year the MISO PRA cleared at $5/MW-Day, 79% lower than the weighted average price from the IPA's procurements.

It is uncertain what the MISO PRA results will be for the next delivery year, and whether the same regional shortage of capacity will occur. The results of the 2022 MISO-OMS Survey indicate that MISO is projected to have a shortfall of 2.6 GW which will primarily affect the MISO North/Central region.[180] However, the same survey also notes that depending on market responses to the results of the 2022-2023 MISO PRA the projected surplus could be as much as 2.4 GW. The results from the MISO PRA have been beneficial to Zone 4's eligible retail costumers except for the 2015-2016 Delivery Year and the most recent 2022-2023 Delivery Year. However, while faced with a high level of uncertainty, it is also important to be prudent in managing price risk. In this regard the IPA proposes making an adjustment to its current hedging strategy for the 2024-2025 and 2025-2026 Delivery Years. The proposed adjustment involves adopting a procurement strategy of purchasing up to 75% in the IPA's bilateral procurements and the balance in the MISO PRA (similar to the strategy taken for the 2017-2018 and 2018-2019 Delivery Years). A 75%/25% procurement strategy will mostly hedge Zone 4 eligible retail customers in the event of another price shock in the PRA; however, it will also allow the customers to benefit if the MISO PRA clears at a price that is lower than the price in the IPA's bilateral procurements. The IPA notes that for the Spring 2022 procurement the Zone 4 price was $180.40/MW-Day for 2023-2024, and $150.72/MW-Day for 2024-2025. As customary, the IPA plans to review this hedging strategy in the 2024 Electricity Procurement Plan based on the results of the 2023-2024 MISO PRA and the status of the proposed changes to the resource adequacy construct. More details on the proposed hedging strategy are provided in Section 7.2.

[180] https://cdn.misoenergy.org/20220610%20OMS-MISO%20Survey%20Results%20Workshop%20Presentation625148.pdf

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."[181]

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.*[182]

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 stakeholder comments related to high voltage direct current ("HVDC") 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.[183] 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 summary of the hedging strategy views put forward by stakeholders in written comments solicited by the IPA and a workshop held for the 2023 Plan.

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 only 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

[181] 20 ILCS 3855/1-20(a)(1).

[182] 220 ILCS 5/16-111.5(b)(3)(vi).

[183] 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).

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.

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 for non-utility retail contracts that ran through the 2014-2015 procurement year. More recently, the number of residential customers taking ARES supply has declined. The primary uncertainty surrounding customer switching going forward appears to be the potential for additional retail load migration back to the utilities. For Ameren Illinois and ComEd, the switched load percentage is expected to remain essentially flat over the 5-year forecasting horizon. MidAmerican's switched load is projected to grow slightly before leveling off but will remain a much smaller part of its total Illinois load (less than 5%).

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 volume 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.

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 forecast to be met by the Illinois-allocated MidAmerican resources. Following the approach started for the 2016 Plan and continued under the 2017, 2018, 2019, 2020, 2021, and 2022 Plans, for the 2023 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). The Ameren Illinois capacity needs have 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. For the 2023 Plan the IPA proposes to procure up to 75% of these needs through the IPA procurements with the balance to be procured through the PRA.

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.[184]

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.[185] 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.[186] 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.[187] The level of bidding competitiveness can be gauged by the breadth of participation by bidders in the procurement.

[184] 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.

[185] 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.

[186] 220 ILCS 5/16-111.5(b), (e), (f).

[187] 220 ILCS 5/16-111.5(f).

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 help 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 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. As noted in Section 2, 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.

Under Public Act 102-0662, procurements of standard wholesale products may now 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.

The IPA received comments through the stakeholder comment process and workshop held in preparation for this Plan that included information regarding the availability and applicability of HVDC products.[188] The IPA assessed the information available regarding the HVDC products that could be used by the Agency as a suitable risk management tool. The IPA's initial assessment identified several issues and uncertainties that would have to be addressed prior to incorporating HVDC products into a risk management strategy and an IPA Procurement Plan, including:

- The HVDC project with the most development progress would involve a 350 mile long, 525 kV transmission line capable of transmitting 2,000 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 and is currently not expected until 2027.[189] The uncertainty

[188] See comments of SOO Green at https://ipa.illinois.gov/content/dam/soi/en/web/ipa/documents/comments-page/soo-green.pdf.

[189] See: https://www.utilitydive.com/news/transmission-developer-files-complaint-with-ferc-against-pjms-catch-22-o/602686/ which describes delays from the original in service date of 2024 to 2026, which has according to the SOO Green comments submitted to the IPA is now expected to be in 2027.

regarding the project's commercial operation date raises the question of when should the IPA consider products from the HVDC project for inclusion in the procurement process?

- This HVDC transmission link would offer a path for the transmission of wholesale energy and capacity products but, with the proposed terminus of the line in PJM, the IPA would only be procuring energy for ComEd's eligible customers that would be delivered through the HVDC line. How would this affect the economics of the project and the IPA's hedging strategy?
- Merchant HVDC projects, such as the project referenced above, typically require long-term transmission contracts with terms of 15 to 20 year to be signed ahead of financing and construction. Since the IPA's procurement horizon is focused on three years, how could such long-term contracts fit into the IPA's statutorily defined procurement process, and risk management strategy? Would the IPA hold a separate competitive procurement event to procure transmission capacity from suppliers of transmission capacity? What risks would a long-term transmission contract help to mitigate? What risks would a long-term transmission contract introduce into the utilities' supply portfolios? Would a long-term contract have inherent risks that outweigh perceived benefits?
- The IPA understands that the proposed HVDC project only offers transmission service; this means that electricity supply and the corresponding utility contracts would have to be matched to the transmission capacity under contract. How can these contract arrangements be accommodated by the IPA's procurement process? Would the IPA hold competitive procurements of electricity supply transmitted over the HVDC line and delivered to the utility load zone? How would this supply compete on price with conventional products?

For this draft 2023 Electricity Procurement Plan, the Agency welcomes stakeholder comments on these questions and any other issues related to how the Agency could consider the procurement of energy supplied by an HVDC transmission line in a manner that would bring benefits to eligible retail customers. Furthermore, the Agency proposes to hold workshops on the potential procurement of energy from HVDC transmission lines in early 2023 to inform consideration of such proposals in the 2024 Electricity Procurement Plan.

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-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).[190] 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 5 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."[191] 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.[192]
- 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.[193]
- 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

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

[191] 220 ILCS 5/16-111.5(b)(4).

[192] As the state's renewable portfolio standard has transitioned as 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)).

[193] 125 FERC ¶ 61,064, Oct. 16, 2008.

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 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.

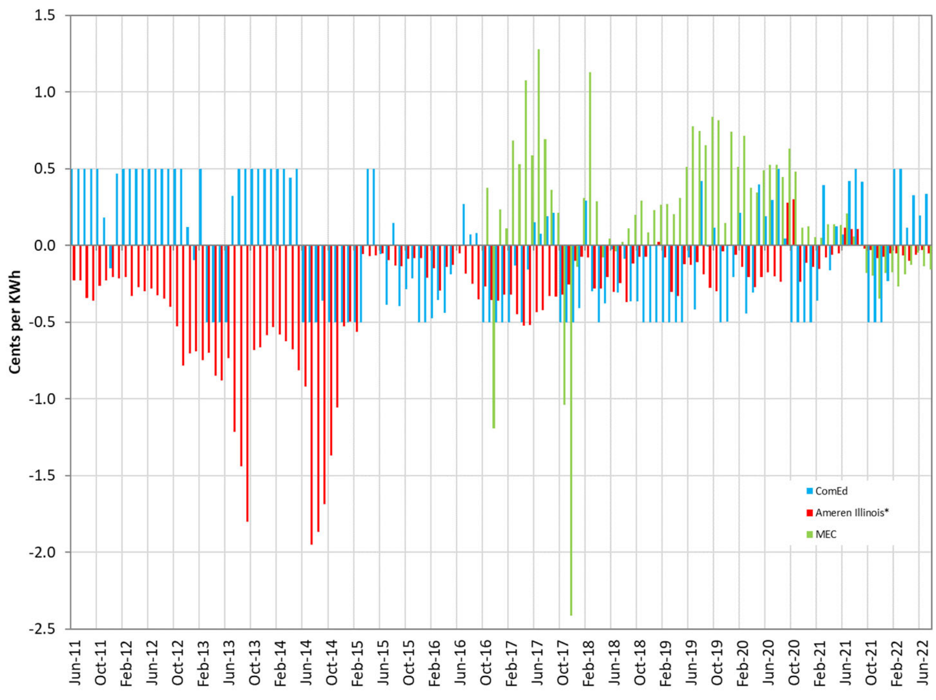
The PEA provides some guidance as to the amount by which the complete set of risk factors caused the cost of energy supply to differ from utility estimates. Figure 6-1 shows how the PEAs for Ameren Illinois and ComEd have changed over the last eleven years. The figure also shows the applicable MidAmerican PEAs starting with October 2016. While Ameren Illinois' PEAs have been generally "negative" (i.e., operating as a credit to customers) since the early part of this period, ComEd's have been "negative" as well as "positive" (i.e., operating as charge to customers). ComEd has voluntarily limited its PEA to move between +0.5 cents/ kWh and -0.5 cents/kWh throughout this period, and the figure shows that ComEd's PEA has oscillated between those limits. Although based on a relatively short period, the MidAmerican PEA exhibited significantly more volatility during late 2016, 2017 and early 2018, ranging from a negative 2.415 cents/kWh in November 2017 to a positive 1.277 cents/kWh in June 2017and a positive 1.127 cents/kWh in February 2018. MidAmerican's PEA has exhibited less volatility since then and was consistently positive from July 2018 through August 2021 before turning negative September 2021 through June 2022.

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. The ComEd PEA also reflected charges in August 2015, June through September 2016, June through September 2017, in February 2018, in August 2019, in October 2019, February 2020, in May through September 2020, in March 2021, in May through September 2021, and from February through June 2022. The ComEd PEA reflected credits for most of the other months in the eleven-year period.

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 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 through May 2021 ranging from -0.005 cents/kWh to -0.561 cents/kWh with small positive values in December 2018 and January 2019. September 2020 and October 2020 had positive PEA values of 0.280 cents/kWh and 0.301 cents/kWh respectively. PEAs for June 2021 through August 2021 exhibited positive values before reverting to negative values for September 2021 through June 2022.

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, ranging from a negative 0.077 cents/kWh in April 2018 to a positive 0.836 cents/kWh in September 2019. Since September 2019 MidAmerican's PEAs have exhibited declining positive values, turning negative in September 2021 and remaining negative through June 2022.

Figure 6-1: Purchased Electricity Adjustments in Cents/kWh, June 2011 – June 2022



*Uniform across all zones in the Ameren Illinois service territory since Oct. 2013. For previous months, values differed slightly by Zone.

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, 2018, 2019, 2020, 2021, and 2022 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 2023 Procurement Plan, the IPA proposes to continue the use of two procurement events to be held in the spring and fall, although as described below and in Section 7.1, the IPA is proposing a change in the hedging targets for each procurement event. This proposed change in hedge targets is the direct result of unexpected market volatility that occurred in the spring of 2022.

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 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, the IPA proposes to increase the percentage of summer load to be hedged in early procurement events in such a way that the procurement volumes to be hedged in the spring prior to delivery be reduced by about half. The table below illustrates the cumulative targets for July and August on-peak by procurement event and reflect a phase-in of the procurement for delivery years 2024, 2025, 2026, 2027, and 2028. Targets to be used in the Spring and Fall 2023 procurement events are specified in Section 7.1.1 of this Plan.

Table 6-1: Proposed Cumulative Procurement Targets

	July and August on-peak for Calendar Year					
	2023	**2024**	**2025**	**2026**	**2027**	**2028**
Procurement Event						
Fall 2022*	50%	25%				
Spring 2023	106%	52.5%	15%			
Fall 2023		75%	30%			
Spring 2024		106%	52.5%	15%		
Fall 2024			75%	30%		
Spring 2025			106%	52.5%	15%	
Fall 2025				75%	30%	
Spring 2026				106%	52.5%	15%

* Approved targets in the 2022 Plan.

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 high energy prices and increased volatility in the most recent energy and capacity procurements. Volatile market conditions 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.

In 2020, the IPA conducted an analysis for the 2021 Plan related to procurement scheduling and volatility. That analysis has been updated for the 2023 Plan. The updated analysis examines 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. The expectation is that shortening the time interval between the Agency's procurement event and the initial delivery month, in conjunction with using multiple annual procurement events, can result in an improved portfolio with lower price volatility.

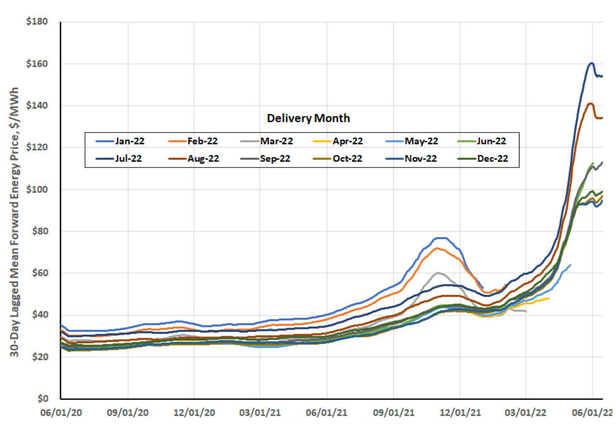
The results of the updated analysis for the 2023 Plan indicate that the closer the procurement events are held to the product delivery date, the greater the price volatility on the hedges procured. Also, a review of monthly forward market volatilities does not support a preference for any periods of 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, has produced the lowest volatility of portfolio price.

6.7 Number and Timing of Procurement Events

The 2020 analysis for the 2021 Procurement Plan considered 2, 3, and 4 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 for delivery months in 2022 shows that the volatility and price trends previously observed in 2017 through early 2020 continued into most of 2021. Figure 6-1 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.

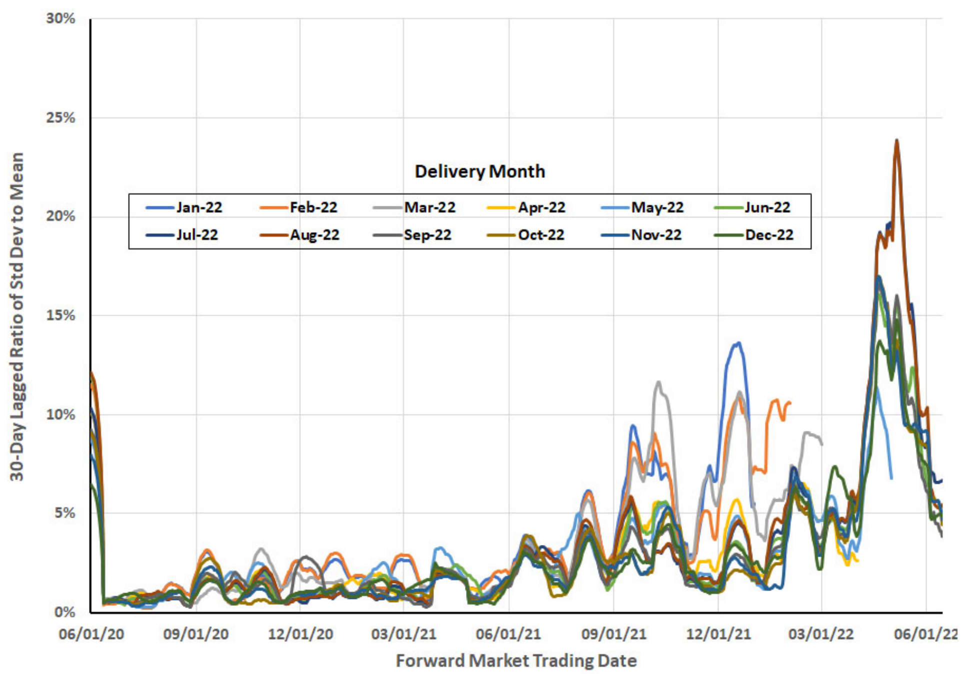
Figure 6-2: Northern Illinois Daily Forward Prices for 2022 Delivery Months



The prices appear to be stable through October 2021, when the winter month prices briefly spike. Prices dropped and level 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 standard deviation for the 30 days of prices represented by each point in the previous chart are 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

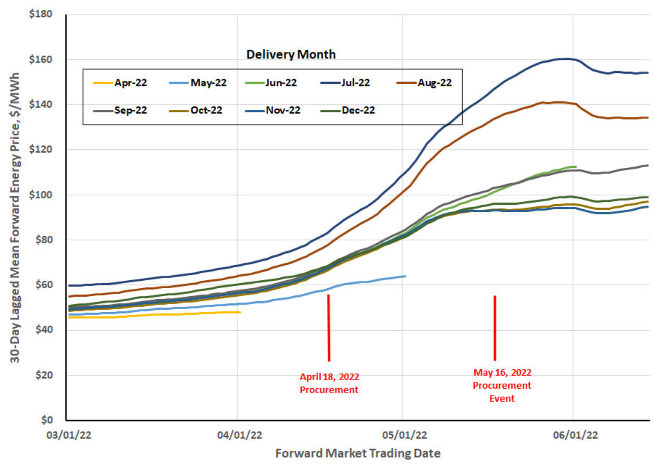
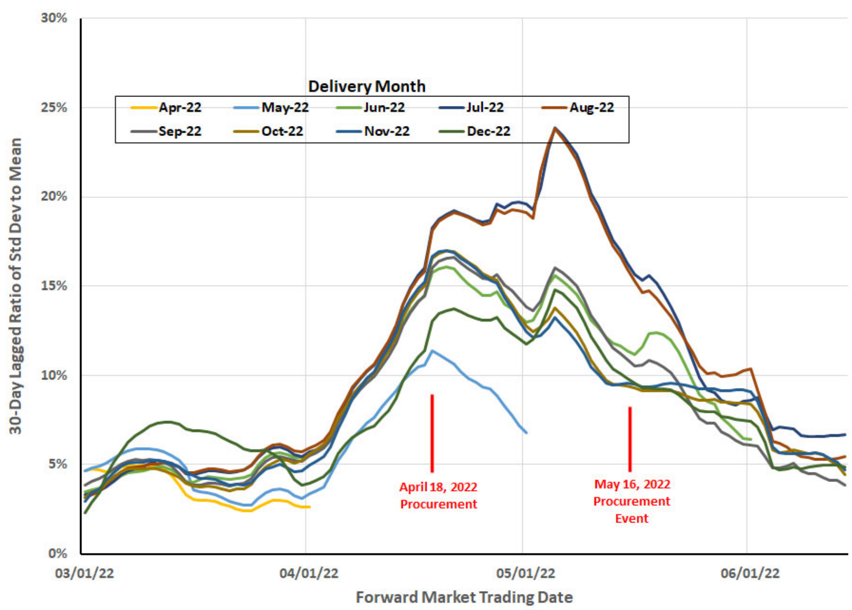


Figure 6-5 - Northern Illinois Daily Forward Prices for April – December 2022 Delivery Months (Standard Deviation as % of Mean)



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.

Review of Proposed Changes to Hedge Volumes to be Procured in the Last Procurement Event for 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 alternative 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

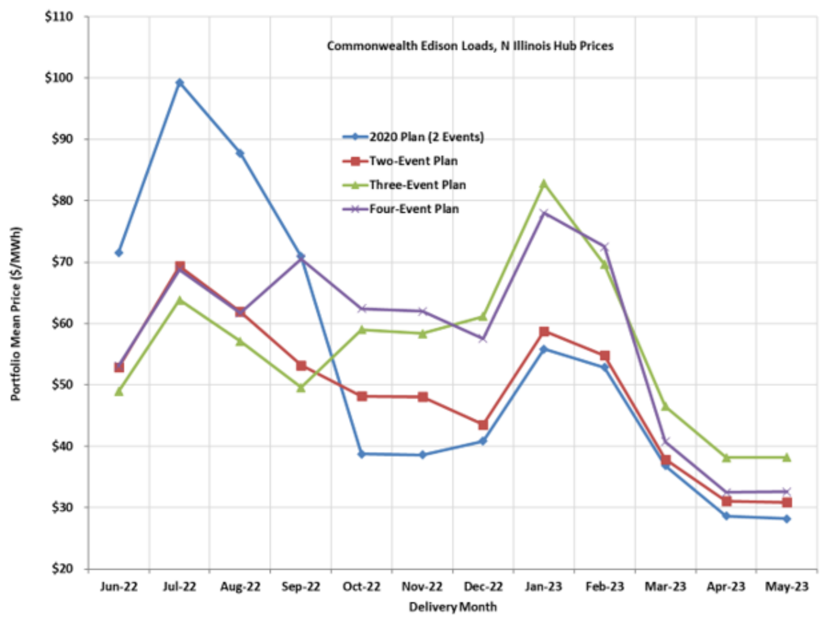
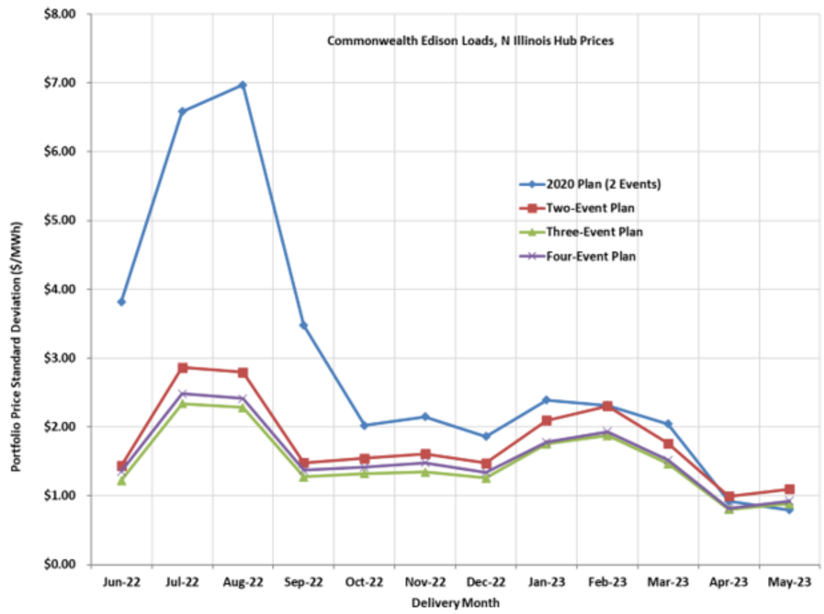


Figure 6-7 – Hedge Portfolio Price Standard Deviation



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 short. 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 an analysis for the 2022 Plan 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.[194] This modeling approach has three basic steps for characterizing price volatility of a particular forward product. The data sample analyzed

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

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 the lognormal distribution more than the 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 eight. Figure 6-8 and Figure 6-9 depict the calculated term structure of average volatility applicable to ComEd and Ameren Illinois wholesale markets.

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

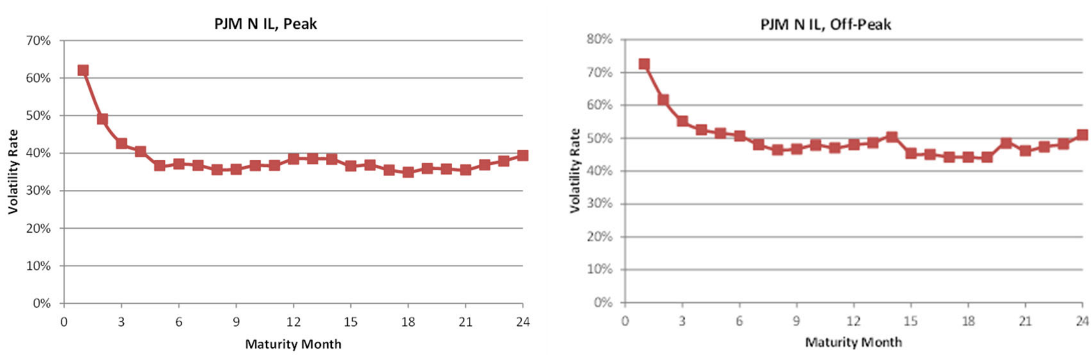
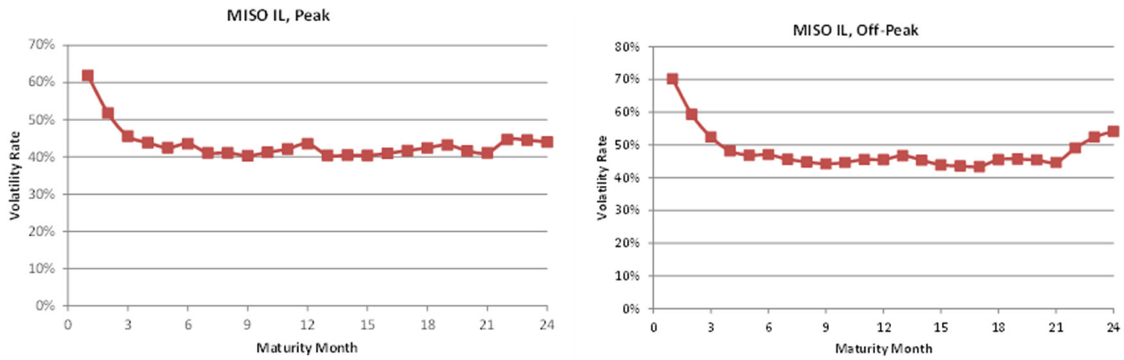


Figure 6-9: MISO Illinois, Volatility Term Structure



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 expiry.

The conclusions, based on the analysis conducted for the 2021 Plan remain relevant for the 2023 Procurement Plan. Taking into consideration the changes proposed for the summer month procurement targets, the IPA proposes to continue the energy procurement schedule and hedging approach utilized in the prior Plans.

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, however, are supply risk management tools available 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.[195] 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.[196] On February

[195] 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.

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

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.[197] 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.[198] Chapter 7 of this Plan provides details and additional discussion regarding demand response resources.

6.9 Stakeholder Feedback on Procurement and Hedging Issues

On June 27, 2022 the IPA solicited stakeholder feedback regarding its energy and capacity procurement process, hedging strategy and the issues raised by the high prices and volatility encountered during the Spring 2022 procurements through the issuing of a written request for comments.[199] A workshop for stakeholders was held on July 13, 2022. This solicitation and the workshop were intended to give stakeholders the opportunity to provide additional feedback to the IPA regarding issues related to the current procurement process and hedging strategy. The following discussion summarizes the relevant feedback received from stakeholders.

Written comments were received from 13 stakeholders concerning a variety of issues related to the IPA's procurement process, wholesale products, hedging strategy, and policy issues related to the MISO capacity market.[200] Comments related to the procurement process and products were focused on the consideration and the implications of changing energy block size, the timing and frequency of holding procurement events, revisiting full requirements products, and the potential for procuring additional products such as distributed energy and HVDC products. Some of the comments received recommended that specific consideration be given to increasing the procurement of energy and capacity from renewable resources in the annual Plans such as the suggestion for combining the procurement of RECs with physical loading following energy supply. A few stakeholders provided comments suggesting a change in the energy block size and in the number of procurement events to be held each year but most favored retaining the current energy block size and timing of procurement events.

Comments regarding the IPA's electricity hedging strategy focused on summer percentage targets and volumes, the applicability of using carbon mitigation credits ("CMCs") for hedging the energy requirements of ComEd's eligible retail customers, the role that HVDC products could play in the IPA's hedging strategy, issues related to under hedging or over hedging, and possible adjustments to the strategy for hedging the procurement of capacity for Ameren's eligible retail customers. The use of HVDC products by the IPA is discussed in Section 6.3 of this Chapter.

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

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

[199] See: https://ipa.illinois.gov/content/dam/soi/en/web/ipa/documents/2023%20Procurement%20Plan%20Stakeholder%20Feedback%20Request%20Final%20%20(6-26-22).pdf.

[200] The written stakeholder comments can be viewed on the IPA's website at https://ipa.illinois.gov/energy-procurement/plans-under-development/comments.html

As discussed elsewhere in this Plan, for the 2023 Plan, the IPA proposes to adjust the summer delivery month procurement targets starting to reduce the amount of energy that must be procured for the prompt summer delivery months in the spring procurement events as discussed in Section 6.7 of this Chapter.

Several stakeholders provided comments regarding the use of CMCs as part of the IPA's hedging strategy. Comments supporting the consideration of CMCs for hedging ComEd's eligible retail customer load focused on the CMC consumer protection mechanism in which the CMC price is indexed to the PJM busbar price of the resources providing CMCs. 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. These payments would help offset the impact of higher wholesale prices on retail customers, including ComEd's eligible retail customers. The effectiveness of the CMC hedge is dependent on maintaining a significant portion (up to 50%) of ComEd's eligible retail customer load unhedged by fixed price contracts procured by the IPA, exposing these customers to significant under hedging risks if CMCs do not prove to be an effective hedge. Issues raised by Stakeholders recommending caution with regard to using CMCs as hedges included the impact of the timing disconnect between when CMC true-up payments are made and when IPA must make procurement decisions, the more complicated hedging strategy administration associated with including CMCs which impact only ComEd's eligible retail customers, the potential for CMC payments to vary from a cost to a credit, and the concern that there is no physical energy supply included with the CMC contracts.

The IPA considered comments related to the use of CMCs as a hedge for ComEd's eligible retail load; and for this draft 2023 Electricity Procurement Plan, the IPA is not proposing adjustments to the hedging strategy for ComEd eligible retail customers in light of the presence of CMC contracts for the next five years. The IPA is not yet convinced that the benefits (or costs) of CMCs for eligible retail customers is sufficiently different from that of customers served by ARES, such that CMCs should be used to leave such a large a portion of eligible retail customers' supplied load unhedged. Furthermore, the IPA is concerned with potential unintended consequences to volatility in spot markets that would result from such large open positions. The timing between the monthly variation of the Purchased Electricity Adjustment that would reflect those spot market purchases and the adjustment to the level of the CMC charge/credit could also create arbitrage issues for customers who switch between default service and ARES offers. The Agency plans to monitor the impact on ComEd's customers of the implementation of the CMC Procurement Plan before determining whether this potential hedge would be appropriate for inclusion in a future Plan. The Agency also welcomes additional stakeholder comments on this draft Plan that make the case for or against adjusting ComEd eligible retail customer procurement volumes.

Comments provided regarding the IPA's procurement process involved the frequency and timing of procurement events, the energy block size and related process adjustments. Several stakeholders also provided comments on the IPA's Ameren capacity procurement and hedging strategy relating to the mix of capacity procured from the IPA's bilateral procurements and capacity procured from the MISO PRA. The IPA proposes to change the amount of capacity procured from the IPA's procurements from the current 50% 75% with the remainder being procured from the MISO PRA. A few comments from stakeholders suggested increasing the energy block size to 50 MW, the IPA remains convinced that the current 25 MW energy block size is the most efficient in terms of avoiding significant mismatches with the utilities' load requirements.

Comments were also provided regarding the potential impact of the changes proposed for the MISO resource adequacy construct focusing on what changes would have to be made to the capacity procurement strategy if MISO's proposed seasonal resource adequacy construct and the minimum capacity obligation were to be implemented. Implementation of these changes by MISO would necessitate changes to the IPA's capacity procurement strategy as described in Section 5.2.2.1. Also, in response to policy issues relating to the MISO capacity market and the proposed changes, the IPA asked for comments regarding the viability of moving MISO

Zone 4 into PJM or combining MISO Zone 4 with the ComEd PJM capacity region into an Illinois RTO. Most stakeholder comments expressed very little support for either of these policy changes.[201]

[201] On July 21, 2022 the ICC opened a docket that ordered a cost-benefit analysis of Ameren's membership in MISO or another RTO. See https://icc.illinois.gov/docket/P2022-0485/documents including the recommendations of the Staff Report to open this proceeding.

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 proposed energy hedging strategy for the 2023 Procurement Plan is consistent with the strategy used for the 2022 Plan with the exception of the proposed change explained below:

- 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 2023, one in the Spring and one in the Fall.

Proposed Change: The change from the 2022 Plan proposed for the 2023 Plan is designed to reduce the volumes to be procured in the Spring procurement event for the immediate summer months (June, July, and August) following the Spring event. The proposed approach is to increase the percentage of summer load to be hedged in early procurement events in such a way that the procurement volumes to be hedged in the spring prior to delivery be significantly reduced by about half. The goal of this change is to mitigate the impact that a potential price spike may have on the prompt summer months, such as the one that occurred in 2022.

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 prompt Delivery Year (2023-2024), 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 second Delivery Year (2024-2025) 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 third Delivery Year (2025-2026) 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%.

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 prompt Delivery Year (2023-2024) 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 second Delivery Year (2024-2025) 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 third Delivery Year (2025-2026) 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 Table 7-1.

Table 7-1: Summary of Energy Procurement Strategy for all Utilities[202]

Spring 2023 Procurement			Fall 2023 Procurement		
June 2023-May 2024 (Upcoming Delivery Year)	**Upcoming Delivery Year+1**	**Upcoming Delivery Year+2**	**October 2022-May 2023**	**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%.

7.1.2 Energy Procurement Implementation

The following tables and figures were constructed using each utility's July 2022 base load forecasts to provide indicative procurement values for the 2023-2024 Delivery Year.[203] The actual target procurement volumes used for the Spring and Fall 2023 procurements will be calculated using the March 2023 and the July 2023 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 2026-2027 and 2027-2028) in this Procurement Plan. Therefore, the tables and figures that follow only cover Delivery Years 2023-2024, 2024-2025, and 2025-2026.

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

[203] 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

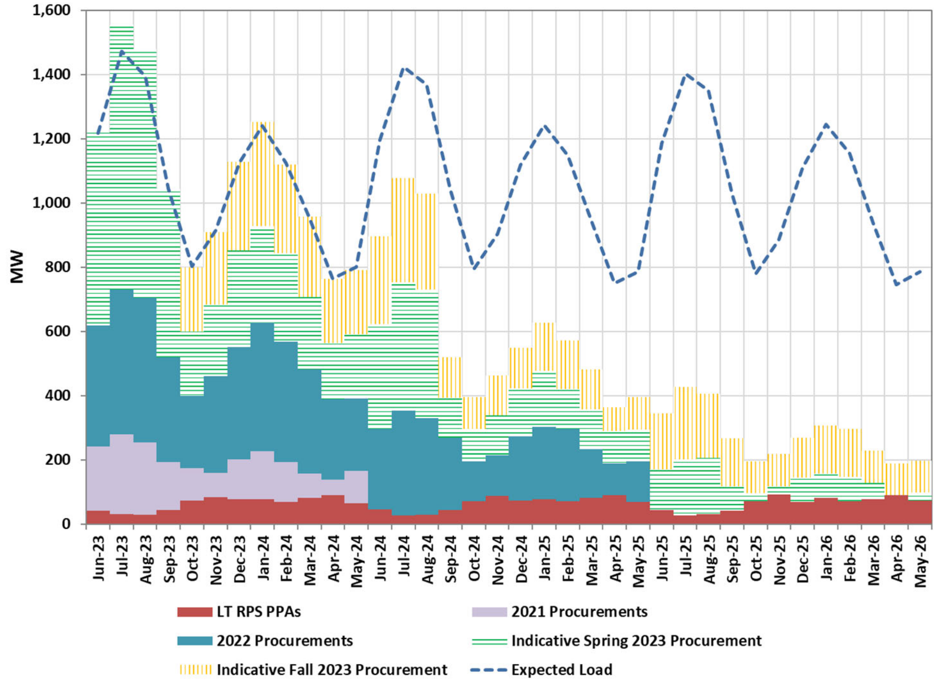


Figure 7-2: Ameren Illinois Off-Peak Energy Supply Portfolio and Load

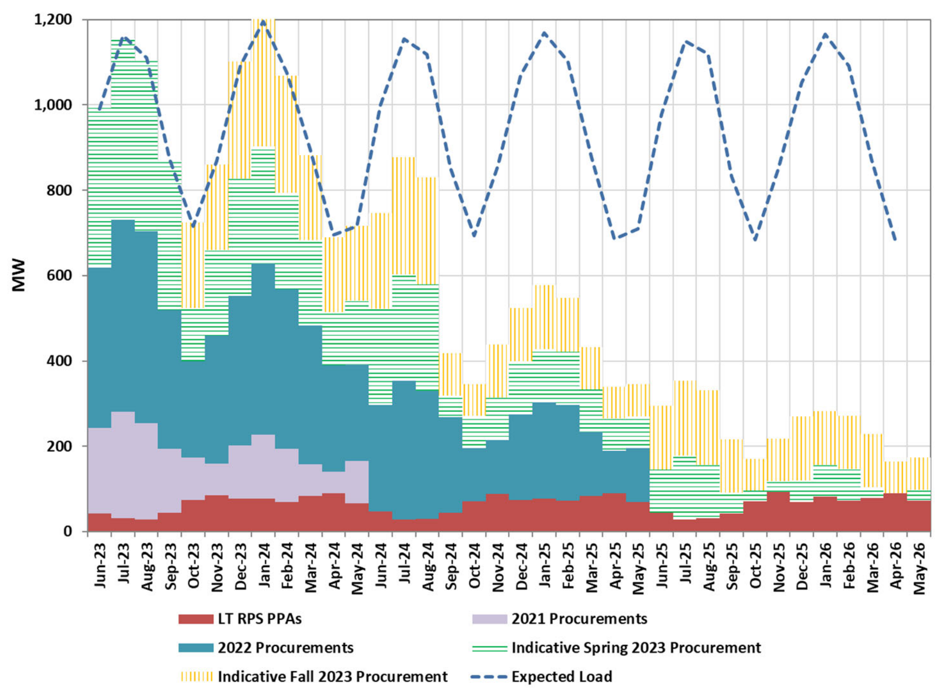


Table 7-2: Ameren Illinois 2023 Spring and Fall Procurements

Delivery Month	Anticipated Spring 2023 Purchases (MW)		Anticipated Fall 2023 Purchases (MW)	
	Peak	Off-Peak	Peak	Off-Peak
Delivery Year 2023-2024				
Jun-23	600	375	0	0
Jul-23	825	425	0	0
Aug-23	775	400	0	0
Sep-23	525	350	0	0
Oct-23	200	125	200	200
Nov-23	225	200	225	200
Dec-23	300	275	275	275
Jan-24	300	275	325	300
Feb-24	275	225	275	275
Mar-24	225	200	250	200
Apr-24	175	125	200	175
May-24	200	150	200	175
Delivery Year 2024-2025				
Jun-24	300	250	300	250
Jul-24	350	300	375	275
Aug-24	350	275	350	300
Sep-24	125	100	125	100
Oct-24	100	75	100	75
Nov-24	125	100	125	100
Dec-24	150	125	125	150
Jan-25	150	150	175	150
Feb-25	150	125	125	150
Mar-25	125	100	125	125
Apr-25	100	100	75	125
May-25	100	100	100	75
Delivery Year 2025-2026				
Jun-25	150	125	150	125
Jul-25	200	150	200	150
Aug-25	175	150	200	150
Sep-25	100	75	125	75
Oct-25	50	50	75	25
Nov-25	75	50	50	75
Dec-25	100	100	100	100
Jan-26	125	100	100	100
Feb-26	100	100	125	100
Mar-26	75	50	75	75
Apr-26	50	25	50	50
May-26	50	50	75	50

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

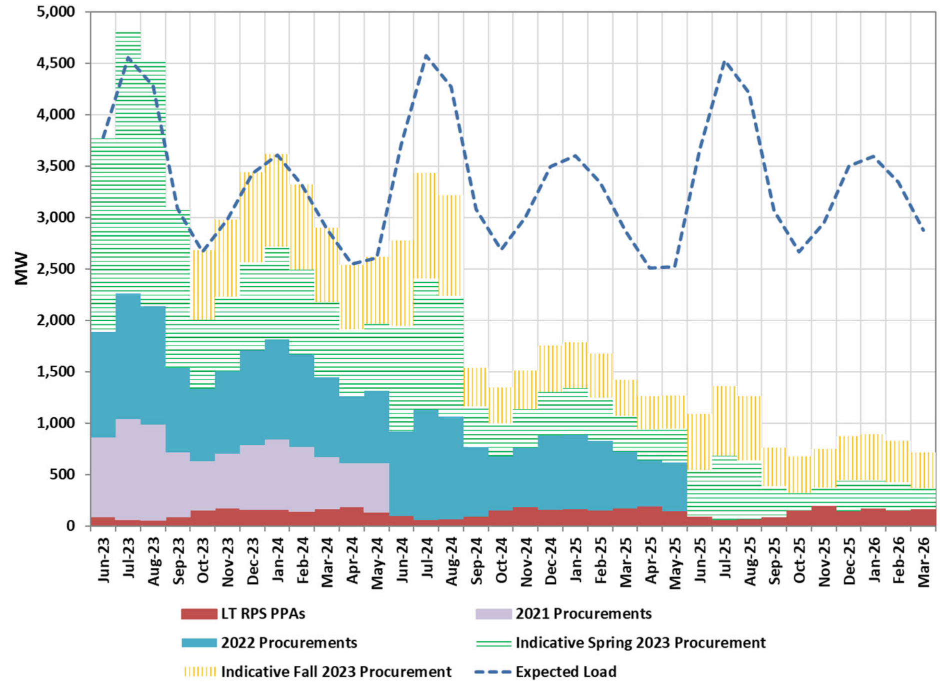


Figure 7-4: ComEd Off-Peak Energy Supply Portfolio and Load

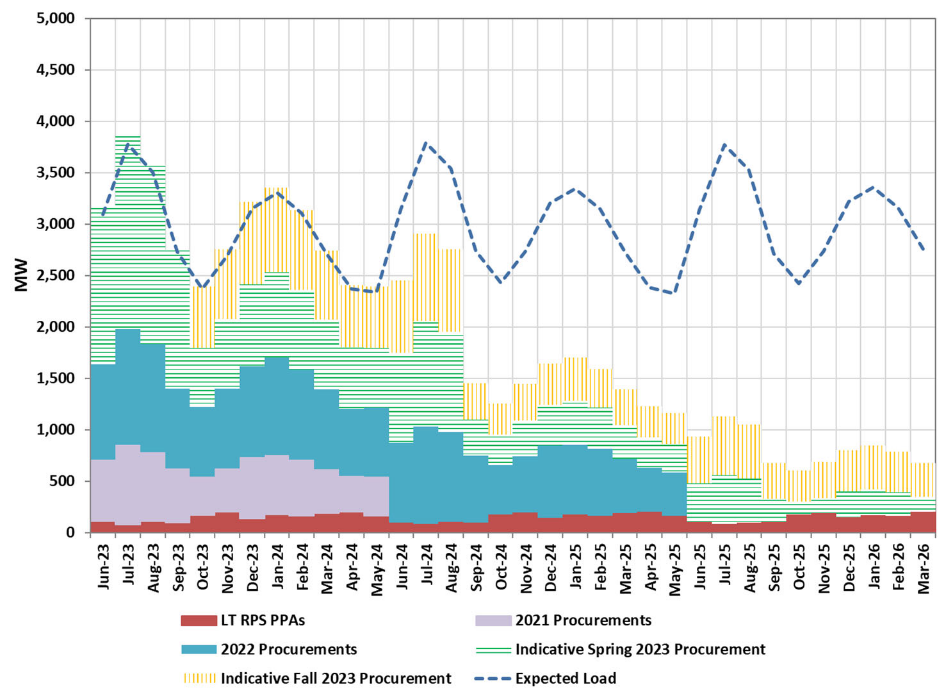


Table 7-3: ComEd 2023 Spring and Fall Procurements

Delivery Month	Anticipated Spring 2023 Purchases (MW)		Anticipated Fall 2023 Purchases (MW)	
	Peak	Off-Peak	Peak	Off-Peak
Delivery Year 2023-2024				
Jun-23	1,875	1,550	0	0
Jul-23	2,550	1,875	0	0
Aug-23	2,400	1,750	0	0
Sep-23	1,550	1,350	0	0
Oct-23	675	575	675	600
Nov-23	725	675	750	675
Dec-23	850	800	875	800
Jan-24	900	825	900	825
Feb-24	825	775	825	775
Mar-24	725	675	725	675
Apr-24	650	600	625	600
May-24	650	575	650	600
Delivery Year 2024-2025				
Jun-24	925	800	925	775
Jul-24	1150	950	1,150	925
Aug-24	1075	900	1,075	875
Sep-24	400	350	375	350
Oct-24	325	300	350	300
Nov-24	375	350	375	350
Dec-24	425	400	450	400
Jan-25	450	425	450	425
Feb-25	425	400	425	375
Mar-25	350	325	350	350
Apr-25	300	300	325	300
May-25	325	275	325	300
Delivery Year 2025-2026				
Jun-25	500	425	500	400
Jul-25	650	525	650	525
Aug-25	600	475	600	475
Sep-25	350	275	325	300
Oct-25	250	225	275	200
Nov-25	275	250	275	250
Dec-25	375	325	350	325
Jan-26	375	325	350	350
Feb-26	350	300	325	325
Mar-26	275	250	275	225
Apr-26	225	200	200	200
May-26	225	200	225	225

Figure 7-5: MidAmerican Peak Energy Supply Portfolio and Load[204]

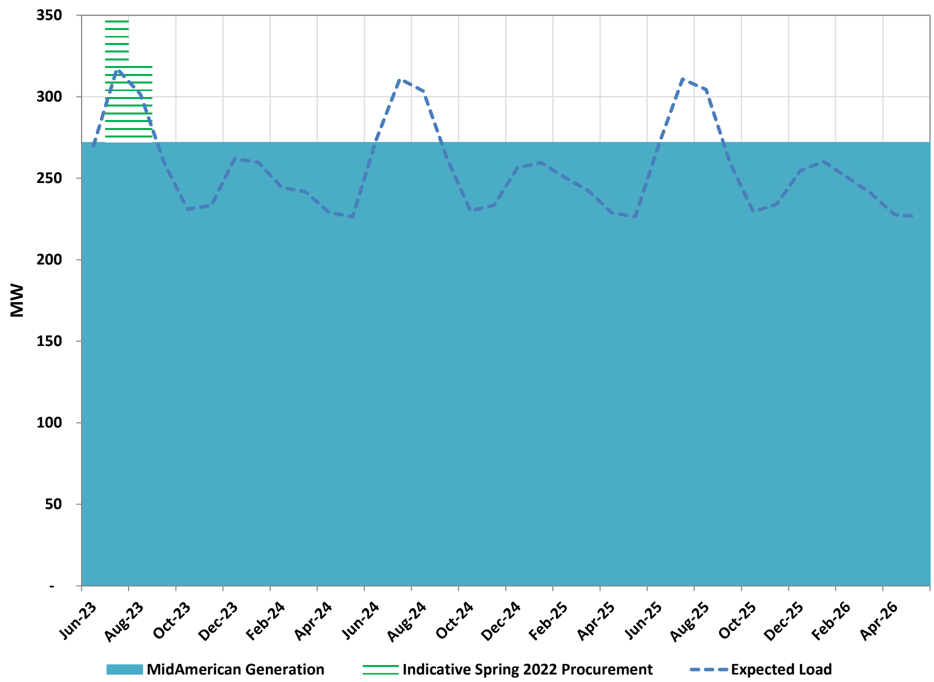
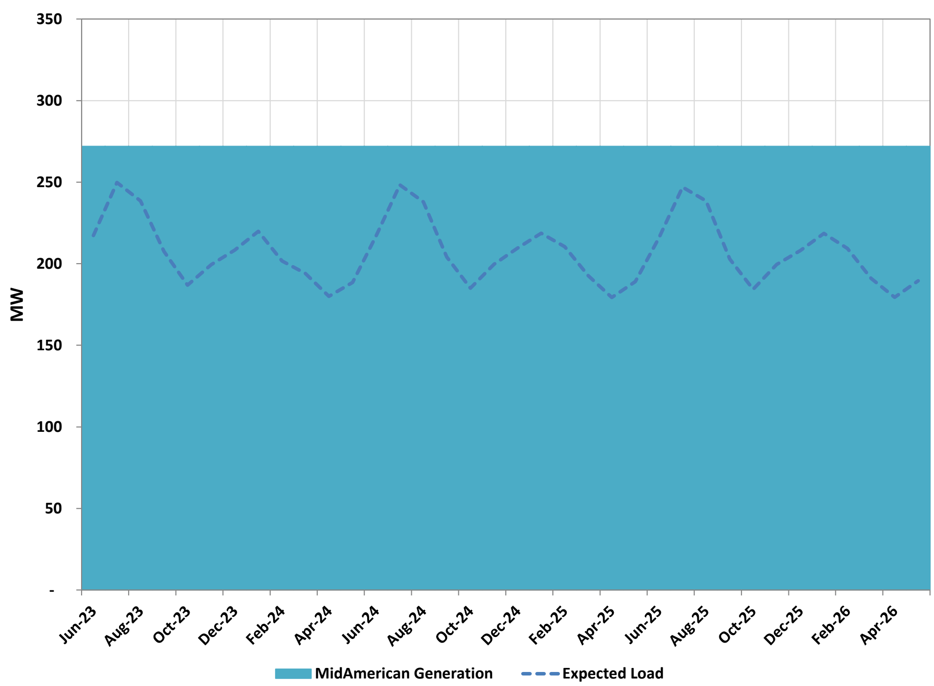


Figure 7-6: MidAmerican Off-Peak Energy Supply Portfolio and Load



[204] 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.

Table 7-4: MidAmerican 2023 Spring and Fall Procurements

Delivery Month	Anticipated Spring 2023 Purchases (MW)		Anticipated Fall 2023 Purchases (MW)	
	Peak	Off-Peak	Peak	Off-Peak
Delivery Year 2023-2024				
Jun-23	0	0	0	0
Jul-23	75	0	0	0
Aug-23	50	0	0	0
Sep-23	0	0	0	0
Oct-23	0	0	0	0
Nov-23	0	0	0	0
Dec-23	0	0	0	0
Jan-24	0	0	0	0
Feb-24	0	0	0	0
Mar-24	0	0	0	0
Apr-24	0	0	0	0
May-24	0	0	0	0
Delivery Year 2024-2025				
Jun-24	0	0	0	0
Jul-24	0	0	0	0
Aug-24	0	0	0	0
Sep-24	0	0	0	0
Oct-24	0	0	0	0
Nov-24	0	0	0	0
Dec-24	0	0	0	0
Jan-25	0	0	0	0
Feb-25	0	0	0	0
Mar-25	0	0	0	0
Apr-25	0	0	0	0
May-25	0	0	0	0
Delivery Year 2025-2026				
Jun-25	0	0	0	0
Jul-25	0	0	0	0
Aug-25	0	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

7.2 Capacity

7.2.1 Capacity Procurement Strategy

7.2.1.1 ComEd

Prior procurement plans, including the 2022 Procurement Plan, have recommended that ComEd obtain its capacity needs through the PJM-administered capacity market. For the 2023 Plan, the IPA recommends that ComEd continue to obtain its capacity needs from the PJM-administered capacity market. Table 7-7 summarizes the proposed capacity procurement for ComEd.

7.2.1.2 Ameren Illinois

For Ameren Illinois, the 2022 Procurement Plan recommended a procurement of a portion of the Ameren Illinois capacity needs for the 2022-2023, 2023-2024, and 2024-2025 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 recommends a continuation of this capacity procurement strategy, but with an adjustment: targeting the procurement of 75% of the capacity requirements in the near-term forward markets through IPA administered RFPs in a laddered fashion, and the remaining balance through the MISO PRA.**

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

- Conduct two procurement events in 2023, one in the Spring and one in the Fall.
- For the 2023-2024 Delivery Year, no change to what was approved in the 2022 Procurement Plan. That is, to procure up to 50% of the forecasted capacity requirements through an RFP administered by the IPA in Fall, 2022, and procure the remaining balance through the MISO PRA scheduled for April of 2023. No additional procurements of capacity for the 2023-2024 Delivery Year will be needed.
- For the 2024-2025 Delivery Year, up to 25% of the forecasted capacity requirements will be procured through an RFP administered by the IPA in Fall, 2022, as outlined in the 2022 Procurement Plan.
- For the 2024-2025 and 2025-2026 Delivery Years, the IPA proposes to procure capacity requirements through its two 2023 capacity procurement events, resulting in hedging at the following levels:
  - At the conclusion of the Spring 2023 procurement event, the target cumulative capacity hedges in Ameren Illinois portfolio of Zonal Resource Credits ("ZRCs") should be as follows:
    - For the 2024-2025 Delivery Year, the target cumulative hedges should be no more than 50% of the capacity requirements.
    - For the 2025-2026 Delivery Year, the target cumulative hedges should be no more than 12.5% of the capacity requirements.
  - At the conclusion of the Fall 2023 procurement event, the target cumulative capacity hedges in Ameren Illinois portfolio of Zonal Resource Credits ("ZRCs") should be as follows:
    - For the 2024-2025 Delivery Year, the target cumulative hedges should be no more than 75% of the capacity requirements.
    - For the 2025-2026 Delivery Year, the target cumulative hedges should be no more than 25% of the capacity requirements.
- Procure the remaining balance of the 2024-2025 Delivery Year capacity requirements through the MISO PRA scheduled for April of 2024. No additional procurements of capacity for the 2024-2025 Delivery Year will be needed.
- Procure the remaining balance of the 2025-2026 Delivery Year capacity requirements in the MISO PRA and/or additional procurement events to be determined in the 2024 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 2025-2026 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 7-5 which presents MidAmerican's load and capability. The IPA, consistent with the discussion regarding the procurement strategy for ComEd, recommends that MidAmerican procure 100% of its forecasted capacity deficit through its RTO's capacity market, the MISO PRA.

Table 7-5: Summary of MidAmerican Load and Capability

	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028
Coincident Peak Load	419	419	418	417	416
Reserves	36	36	36	36	36
Coincident Peak Load with Reserves	456	455	454	453	452
Total Net Capability	385	385	385	385	385
Deficit to Be Procured in MISO PRA	71	70	69	69	68

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 2023 Procurement Plan to assure reliability over the planning horizon. For the 2023-2024 Delivery Year, the IPA recommends no changes from the previously approved strategy. For the 2024-2025 and 2025-2026 Delivery Years, the IPA recommends a continuation of the strategy of procuring Ameren Illinois capacity requirements through IPA-administered RFPs and through the MISO PRA, as shown below in Table 7-6.

The figures in this table were constructed using Ameren Illinois July 2022 base load forecasts to provide indicative procurement values for the 2024-2025 and 2025-2026 Delivery Years. The target Zonal Resource Credits ("ZRCs") procurement volumes to be used for the Spring and Fall 2023 procurements will be calculated using the March 2023 and the July 2023 updated load forecasts respectively. For the 2025-2026 Delivery Year, any additional procurements to be conducted in 2024 will be determined in the 2024 Procurement Plan. Consistent with the recommendation in Section 7.1.2, the IPA recommends that Ameren Illinois submit forecast updates inclusive of capacity requirements that reflect the most accurate and up-to-date information and modeling available at the time.

Table 7-6: Summary of Capacity Procurement for Ameren Illinois[205]

Delivery Year	Requirement	Spring 2021 RFP	Fall 2021 RFP	Spring 2022 RFP	Fall 2022 RFP	April 2023 PRA	Additional Procurements
June 2023 - May 2024	2,130 ZRCs	Quantity not disclosed[206]	34 ZRCs Procured	807 ZRCs Procured	204 ZRCs Targeted for Procurement	Balance of Requirements, 1,065 ZRCs estimated	0 ZRCs

[205] Procurements results for the scheduled Fall 2021 procurement events and April 2022 PRA volume are estimates.

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

Delivery Year	Requirement	Spring 2022 RFP	Fall 2022 RFP	Spring 2023 RFP	Fall 2023 RFP	April 2024 PRA	Additional Procurements
June 2024 - May 2025	2,121 ZRCs	286 ZRCs Procured	244 ZRCs Targeted for Procurement	530 ZRCs Targeted for Procurement	530 ZRCs Targeted for Procurement	Balance of Requirements, 530 ZRCs estimated	0 ZRCs
Delivery Year	**Requirement**	**Spring 2022 RFP**	**Fall 2022 RFP**	**Spring 2023 RFP**	**Fall 2023 RFP**	**April 2025 PRA**	**Additional Procurements**
June 2025 - May 2026	2,113 ZRCs	0 ZRCs	0 ZRCs	264 ZRCs Targeted for Procurement	264 ZRCs Targeted for Procurement	Not Available	To be determined in 2024 Plan

7.2.2.2 ComEd

For ComEd, the IPA concludes that it does not need to include any extraordinary measures in the 2023 Procurement Plan to assure reliability over the planning horizon. The IPA, as indicated below, recommends that ComEd 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 7-7: Summary of Capacity Procurement for ComEd

June 2023-May 2024 (Upcoming Delivery Year)	June 2024-May 2025	June 2025-May 2026	June 2026-May 2027
100% PJM RPM Auctions*	100% PJM RPM Auctions**	100% PJM RPM Auctions***	100% PJM RPM Auctions****

* PJM RPM Base Residual Auction for 2023-2024 has already cleared.

**The 2024-2025 auction will be held on December 7, 2022.

*** The 2025-2026 auction will be held in June 2023.

*** The 2026-2027 will be held in November 2023.

7.2.2.3 MidAmerican

For MidAmerican, the IPA concludes that it does not need to include any extraordinary measures in the 2023 Procurement Plan to assure reliability over the planning horizon. The IPA recommends that MidAmerican continue to procure 100% of its capacity deficit for the 2023-2024, 2024-2025, and 2025-2026 Delivery Years through the MISO PRAs as indicated below.

Table 7-8: Summary of Capacity Procurement for MidAmerican

June 2023-May 2024 (Upcoming Delivery Year)	June 2024-May 2025	June 2025-May 2026
100% of capacity deficit through MISO PRA*	100% of capacity deficit through MISO PRA**	100% of capacity deficit through MISO PRA***

* MISO Auction for 2023-2024 is expected to clear in April 2023.
** MISO Auction for 2024-2024 is expected to clear in April 2024.
***MISO Auction for 2025-2026 is expected to clear in April 2025.

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.*[207]

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."[208] This updated requirement now "continues until December 31, 2026."[209]

ComEd provided information[210] 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 65,000 customers with a load reduction potential of 65 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 933 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 35,600 customers and a load reduction potential of 2.14 MW.
- Peak Time Savings (PTS) Program: This program is required by 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 348,00 customers in 2022.ComEd sold 80 MW in the 2021-2022 Delivery Year, 90 MW of summer only capacity for the 2022-2023 Delivery Year, and 135.5 MW in the 2023-2024 Delivery Year.

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

[207] 220 ILCS 5/8-103(c).

[208] 220 ILCS 5/8-103B(g)(4.5).

[209] Id.

[210] See Appendix C.

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 136,000 customers and Ameren Illinois sold 17.5 MW of related capacity in the MISO PRA for the 2022-2023 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 does not propose any procurement of demand response programs from eligible retail customers in the 2023-2024 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] 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.[211] As a part of the goal, the Plan must also include electricity generated from clean coal facilities.[212] While there is a broader definition of "clean coal facility" contained in the definition section of the IPA Act,[213] Section 1-75(d) describes two special cases: the "initial clean coal facility"[214] 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"[215] ("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.

[211] 20 ILCS 3855/1-75(d).

[212] 20 ILCS 3855/1-75(d)(1).

[213] 20 ILCS 3855/1-10.

[214] Id.

[215] 20 ILCS 3855/1-75(d)(5).

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"[216] (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."[217] 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 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 proposing 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.

[216] 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.

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

8 Procurement Process Design

The procedural requirements for the procurement process are detailed in the Illinois Public Utilities Act at Section 16-111.5.[218] The Procurement Administrator, retained by the IPA in accordance with Section 1-75(a)(2) of the IPA Act, conducts competitive procurement events on behalf of the IPA. The costs of the Procurement Administrator incurred by the IPA are recovered from the bidders and suppliers that participate in the 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. As required by the PUA and in order to operate in the best interests of consumers, the IPA and the Procurement Administrator review the procurement process each year in order to identify potential improvements.[219] 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 new requirements enacted through the Climate and Equitable Jobs Act (Public Act 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 subsection (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. The Agency will not procure any wholesale energy products from bidders that fail to comply with these requirements.

The Climate and Equitable Jobs Act also established labor standards in subparagraph(Q) of paragraph (1) of subsection (c) of Section 1-75 of the IPA Act, which are currently applicable to bidders participating in REC procurements.

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 the annual procurement plan. The procurement of RECs is instead covered by the Long-Term Renewable Resources Procurement Plan.[220] 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[221], provide supply requirements, and otherwise explain the competitive procurement process. In addition to such

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

[219] 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.

[220] 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.

[221] 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.

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 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 2022, the process to receive comments from potential bidders can be restricted to changes to the forms, 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. Any procurement event to be conducted under the auspices of the 2023 Procurement Plan would be the seventeenth iteration of IPA-run procurement events, when including the Spring and Fall 2022 procurement events for the procurement of capacity for Ameren Illinois and the procurement of standard energy products for Ameren, ComEd and MidAmerican. 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 2022, 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 2022 capacity procurements to accommodate the possibility that proposed changes to the MISO resource adequacy construct would result in changes to the MISO capacity products to be procured for Ameren's eligible customers. The IPA anticipates that this amendment will remain in place for the 2023 Plan capacity procurements pending FERC approval of MISO's Seasonal Capacity and Accreditation Requirements filling which would require an update to the current Ameren Capacity Agreement.

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.

On the opposite side of this discussion, the IPA also understands that markets are dynamic and periodic review of contract terms is necessary to ensure proper protection for the utilities, utility customers and suppliers. The IPA therefore recommends that the most recently used forms, namely the energy contracts used in the 2022 procurement events, be 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.

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."[222] 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.[223]

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.
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

[222] 20 ILCS 3855/1-75(h).

[223] 83 Ill. Admin. Code. §§ 1200.110, 1200.220.

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 date certain (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 2022 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

The IPA recommends that procurement events continue to be held in the spring and fall of 2023 for the purchase of energy blocks and a portion of the necessary Ameren Illinois capacity products (Zonal Resource Credits) under the 2023 Procurement Plan. The components of the procurement process detailed above would be conducted in the spring events. For the fall procurement events, for energy blocks under the Procurement Plan, certain activities would not occur as the fall procurement event could rely on the documents or processes established for the spring procurement event, as follows:

- The procurement administrator will rely on the contract and credit forms established in the Spring 2023 procurement event, and suppliers would not comment anew on these documents;
- The procurement administrator will rely on the RFP design and updated benchmarks using the benchmark methodology established in the Spring 2023 procurement event; and
- The procurement administrator, in consultation with each utility, IPA, ICC Staff and Procurement Monitor, will not be prohibited from making minor changes to the contract and credit terms or minor changes to the RFP documents, including but not limited to clarifications or corrections.

- Suppliers that participate in the Spring 2023 procurement event will have access to an abbreviated qualification and registration process if they also participate in the Fall 2023 procurement event;

The IPA recommends that the Fall 2023 procurement event includes the procurement of standard energy products for Ameren Illinois, ComEd, and MidAmerican (if needed), as well as Zonal Resource Credits for Ameren Illinois.

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 12, 2022, the ICC Staff posted a public notice[224] for the informal hearing for the purpose of receiving comments regarding the procurement process for the procurement events that were held from Summer 2021 through Spring 2022. The Fall 2021 procurements involved the procurement of standard energy products to meet a portion of the requirements of ComEd's and Ameren Illinois' eligible retail customers for October 2021 through May 2024 and MISO Zonal Resource Credits capacity products for Ameren Illinois for the Delivery Years 2022-2023 and 2023 - 2024. The Spring 2022 procurement events included the purchase of a portion of the three utilities' energy requirements[225] to meet eligible retail customers' needs for the 2022-2023, 2023-2024 and 2024-2025 Delivery Years, as well as the purchase of MISO Zonal Resource Credits for Ameren Illinois for the 2023-2024 and 2024-2025 Delivery Years.

The Spring 2022 procurements solicited energy blocks to meet the total requirements of the utilities' eligible retail customers for the Months of June 2022 through September 2022 as well as a portion of the requirements for the other months in the three delivery years. However, only a portion of the energy requirements targeted in the spring event were procured. Subsequently, in accordance with Section 16-111.5 of the IPA Act, a Supplemental Spring Energy procurement event was held on May 16, 2022. The supplemental procurement targeted the unfilled energy requirements of the three utilities for the months of June 2022 through September 2022. All of the unfilled energy blocks were filled for Ameren Illinois and a portion of the unfilled blocks were filled for ComEd and MidAmerican. The unfilled blocks for the months after September 2022 will be targeted in the Fall 2022 procurement event.

Initial comments for the informal hearing were due to the Commission by May 27, 2022 and Reply Comments were due by May 31, 2022. Initial Comments were received from Bates White Economic Consulting ("Bates White"), the ICC's Procurement Monitor, on May 27, 2022. Bates White provided their perspective on the Spring procurement events and the impact of the volatile market conditions and high prices that were experienced during the Spring 2022 procurements. Bates White 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 and mitigating the risks to ratepayers posed by volatile market conditions characterized by high prices. Bates White specifically commented that "Despite the higher prices the Spring Energy RFPs only underscore the merits of the Illinois' approach to block energy procurement."[226] Bates White continued to support the IPA's use of competitive procurements with bids subject to confidential benchmarks as the best practices that benefit ratepayers. Comments received in the informal hearing process are available on the Commission's website.[227]

[224]https://www.icc.illinois.gov/downloads/public/Public-Notice-of-Informal-Hearing-Electric-Events-Issued-May-4-2021.pdf.

[225] MidAmerican energy blocks were procured in the Spring Supplemental Procurement for July and August 2022 on-peak.

[226] Bates White Economic Consulting, "Initial Comments on the Summer 2021 through Spring 2022 Electric Procurement Events," Presented to the Illinois Commerce Commission May 27, 2022.

[227] See https://www.icc.illinois.gov/program/Electricity-Procurement-Process-for-Plan-Years-Beginning-June-2022.

Appendices (Overview)

Appendices are available separately at:
https://ipa.illinois.gov/energy-procurement/2023-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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- Ameren Illinois Forecasting Methodology July 2022

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