2017

ELECTRICITY PROCUREMENT PLAN

2017 Plan Filed for

Illinois Commerce Commission Approval

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

Table of Contents

Appendices are available separately at:
www2.illinois.gov/ipa/Pages/Plans_Under_Development.aspx

Tables

Figures

1 Executive Summary

This is the ninth electricity and renewable resource procurement plan (the "Plan," "Procurement Plan," or "2017 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 any such plan, including those set forth in previous orders of the Illinois Commerce Commission ("Commission" or "ICC").

The Plan addresses the provision of electricity and renewable resource supply for the "eligible retail customers" of Ameren Illinois Company ("Ameren Illinois"), Commonwealth Edison ("ComEd"), and MidAmerican Energy Company ("MidAmerican"). Following MidAmerican's first-time participation in the 2016 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 2017 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 2017-2018 energy delivery year and lasts through the 2021-2022 delivery year.

The 2016 Procurement Plan, approved by the Commission in Docket No. 15-0541, called for the energy and renewable resources requirements for Ameren Illinois, ComEd, and MidAmerican to be procured by the IPA through two block energy procurements (spring and fall), a spring renewables procurement, and an early summer distributed generation procurement. In addition, the 2016 Plan involved a capacity procurement for Ameren Illinois held as a Fall 2016 procurement event. The 2016 Plan also called for a minor change to the energy hedging strategy to bring the hedging level for October 2016 to 75% of average load at the time of the spring procurement event and to 100% in the fall procurement event. For the 2017 Procurement Plan, the IPA recommends a continuation of the energy procurement strategies proposed in the 2016 Procurement Plan.

1.1 Power Procurement Strategy

The 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 environmentally sustainable electric service at the lowest total cost over time, taking into account any benefits of price stability."[2]

The IPA's hedging strategy for the 2017 Procurement Plan is consistent with the strategy used for the 2016 Plan. The IPA continues to recommend the procurement of standard energy in blocks of 25MW. The risk management strategy also continues to bifurcate the first delivery year into periods with different hedging levels—with June hedged at 100% of average load, July and August hedged to 106% of average on-peak load

[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 2017 procurement planning process.
[2] 20 ILCS 3855/1-20(a)(1).

and 100% of average off-peak load, fall hedged to 100% of average load, and the balance of the year hedged to 75% of average load at the time of the spring procurement event. The IPA also recommends that the Commission approve a fall energy procurement event to bring the hedging level for the balance of the first delivery year (October through May) to the fully hedged level (100% of load). Consistent with other recent procurement plans, the IPA also recommends hedging 50% of the expected load for the second delivery year, and 25% of the expected load for the third delivery year. The IPA recommends the procurement of half of these volumes in the Spring 2017 procurement event and the balance in the Fall 2017 procurement event.

Additionally, for Ameren Illinois' 2018-2019 planning year, the IPA recommends purchasing 75% of its forecasted capacity requirements in bilateral transactions and 25% from the MISO Planning Resource Auction ("PRA").[3] For future years' Ameren Illinois capacity requirements, the IPA will defer a decision for the 2019-2020 planning year and beyond until next year's Plan. For ComEd, consistent with the strategy adopted in prior plans, the IPA proposes that forecast capacity requirements be secured by ComEd through the PJM Reliability Pricing Model and Capacity Performance processes. For MidAmerican, consistent with the approach taken in the 2016 Plan, the IPA recommends that its forecast capacity shortfall be secured by MidAmerican through the annual MISO PRA.[4]

Aside from the various proposals above, the IPA recommends that capacity, ancillary services, load balancing services, and transmission services be purchased by Ameren Illinois and MidAmerican from the MISO marketplace and by ComEd from PJM's.

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

Table 1-1: Summary of Energy Hedging Strategy for all Utilities[5]

Spring 2017 Procurement			Fall 2017 Procurement		
June 2017-May 2018 (Upcoming Delivery Year)	**Upcoming Delivery Year+1**	**Upcoming Delivery Year+2**	**October 2017-May 2018**	**Upcoming Delivery Year + 1**	**Upcoming Delivery Year + 2**
June 100% peak and off peak July and Aug. 106% peak, 100% off peak Sep. 100% peak and off peak Oct. - May 75% peak and off peak	37.5%	12.5%	100%	50%	25%

Table 1-2: Summary of Capacity Procurement for ComEd

June 2017-May 2018 (Upcoming Planning Year)	June 2018-May 2019	June 2019-May 2020	June 2020-May 2021
100% PJM RPM Auctions	100% PJM RPM Auctions	100% PJM RPM Auctions	100% PJM RPM Auctions

[3] 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.

[4] 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); in the case of capacity, MidAmerican's shortfall is relatively small (15.2% to 16.3% of its capacity requirement).

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

Table 1-3: Summary of Capacity Procurement for Ameren Illinois[6]

June 2017-May 2018 (Upcoming Planning Year)[7]	June 2018-May 2019	June 2019-May 2020
75% RFP in Fall 2016 25% MISO PRA	25% RFP in Fall 2016 50% RFP in Fall 2017 25% MISO PRA	To Be Determined In Next Year's Plan

Table 1-4: Summary of Capacity Procurement for MidAmerican

June 2017-May 2018 (Upcoming Planning Year)	June 2018-May 2019	June 2019-May 2020
100% of expected shortfall (approximately 15.2% of the capacity requirements) from MISO PRA	100% of expected shortfall (approximately 15.8% of the capacity requirements) from MISO PRA	100% of expected shortfall (approximately 16.3% of the capacity requirements) from MISO PRA

1.2 Renewable Energy Resources

The load forecast provided by Ameren Illinois indicates that while existing renewable energy resources under contract meet that utility's overall renewable resource obligations for the upcoming delivery year, they do not fully meet or exceed the Renewable Portfolio Standard obligations for solar photovoltaics or for distributed generation. The load forecasts submitted by ComEd and MidAmerican indicate that existing renewable energy resources under contract do not meet those utilities' overall renewable energy resource obligations for the upcoming delivery year or the specific obligations for wind, photovoltaics, or distributed generation.

Accordingly, the IPA recommends conducting a Spring 2017 procurement event for general renewable energy credits ("RECs") (ComEd and MidAmerican only), wind RECs (ComEd and MidAmerican only), and solar RECs (all utilities) using the Renewable Resources Budget. The IPA also proposes two procurements for distributed generation RECs using hourly ACP funds for Ameren Illinois and ComEd, and using the Renewable Resources Budget for MidAmerican. Scheduling of the procurements will be finalized based upon whether the IPA undertakes a contingency procurement in April, 2017 as contemplated in the Agency's the Supplemental Photovoltaic Procurement Plan and other factors. For Ameren Illinois and ComEd, the distributed generation procurement budget will be equal to the amount of hourly ACP funds collected by each utility as of December 31, 2016 for any procurement undertaken prior to June 30, 2017 and updated to the May 31, 2017 balance for any procurement after July 1, 2017, minus the value of contracts awarded through the 2015, 2016, and 2017 distributed generation REC procurements[8] and any hourly ACP funds committed to the purchase of curtailed RECs stemming from the 2010 long-term power purchase agreements ("LTPPAs") should the March updated load forecasts indicate the need for a curtailment.[9]

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[6] Table shows the incremental percentage of capacity requirements to be hedged or purchased in the indicated procurement events.
[7] Procurement approved in the 2015 Procurement Plan.
[8] As the second 2017 distributed generation REC procurement's budget would be impacted by contracts committed to in the first 2017 distributed generation REC procurement.
[9] While the IPA will endeavor to conduct its DG procurements as soon as practicable after Plan approval as requested by commenters on the Draft Plan, because the first of the two DG procurements will almost certainly occur after the March load forecasts are received, those load forecasts will be used to inform a DG procurement budget.

Table 1-5 summarizes the IPA's proposed supply-side recommendations as described in this Plan:

Table 1-5: Summary of Procurement Plan Recommendations Based on July 15, 2016 Utility Load Forecast (Quantities to be Adjusted Based on the March and July 2017 Load Forecasts):

	Delivery Year / Planning Year	Energy	Capacity	Renewable Resources	Transmission and Ancillary Services
AMEREN ILLINOIS	2017-2018	Up to 625MW forecasted requirement (Spring Procurement) Up to 225MW additional forecasted requirement (Fall Procurement)	75% RFP in Sep. 2016 25% MISO PRA	One-year SRECs procurement up to 43.1GWh Five-year DG REC procurement up to 7.0GWh	Will be purchased from MISO
	2018-2019	Up to 150MW forecasted requirement (Spring Procurement) Up to 125MW forecasted requirement (Fall Procurement)	25% RFP in Sep. 2016 50% RFP in Fall 2017 25% MISO PRA	No RPS procurement, other than the five-year DG REC procurement above	Will be purchased from MISO
	2019-2020	Up to 125MW forecasted requirement (Spring Procurement) Up to 125MW forecasted requirement (Fall Procurement)	To Be Determined In Next Year's Plan	No RPS procurement, other than the five-year DG REC procurement above	Will be purchased from MISO
	2020-2021	No energy procurement required	No further action at this time	No RPS procurement, other than the five-year DG REC procurement above	Will be purchased from MISO
	2021-2022	No energy procurement required	No further action at this time.	No RPS procurement, other than the five-year DG REC procurement above	Will be purchased from MISO
COMED	2017-2018	Up to 2,225MW forecasted requirement (Spring Procurement) Up to 800MW additional forecasted requirement (Fall Procurement)	100% PJM RPM Auctions	One-year wind REC procurement up to 500.0GWh One-year SREC procurement up to 107.9GWh Five- year DG REC procurement up to 20.1GWh	Will be purchased from PJM
	2018-2019	Up to 500MW forecasted requirement (Spring Procurement) Up to 500MW forecasted requirement (Fall Procurement)	100% PJM RPM Auctions	No RPS procurement, other than the five-year DG REC procurement above	Will be purchased from PJM
	2019-2020	Up to 475 MW forecasted requirement (Spring Procurement) Up to 450MW forecasted requirement (Fall Procurement)	100% PJM RPM Auctions	No RPS procurement, other than the five-year DG REC procurement above	Will be purchased from PJM
	2020-2021	No energy procurement required	100% PJM RPM Auctions	No RPS procurement, other than the five-year DG REC procurement above	Will be purchased from PJM
	2021-2022	No energy procurement required	No further action at this time	No RPS procurement, other than the five-year DG REC procurement above	Will be purchased from PJM

MIDAMERICAN	2017-2018	Up to 100MW forecasted requirement (Spring Procurement) Up to 75MW additional forecasted requirement (Fall Procurement)	100% of expected shortfall from MISO PRA	One-year wind REC procurement up to 49.2GWh One-year SREC procurement up to 3.9GWh Five- year DG REC procurement up to 0.5GWh	Will be purchased from MISO
	2018-2019	Up to 25MW forecasted requirement (Spring Procurement) Up to 25MW forecasted requirement (Fall Procurement)	100% of expected shortfall from MISO PRA	No RPS procurement, other than the five-year DG REC procurement above	Will be purchased from MISO
	2019-2020	No energy procurement required	100% of expected shortfall from MISO PRA	No RPS procurement, other than the five-year DG REC procurement above	Will be purchased from MISO
	2020-2021	No energy procurement required	No further action at this time	No RPS procurement, other than the five-year DG REC procurement above	Will be purchased from MISO
	2021-2022	No energy procurement required	No further action at this time	No RPS procurement, other than the five-year DG REC procurement above	Will be purchased from MISO

1.3 Incremental Energy Efficiency

This plan is the fifth year for inclusion of incremental energy efficiency programs pursuant to Section 16-111.5B of the Public Utilities Act. As with past plans, the IPA recommends inclusion of the programs submitted by the utilities that pass the Total Resource Cost and have not been determined to be duplicative of other programs. Those programs can be found in Chapter 9. The IPA also recommends that the Commission approve and adopt the Section 16-111.5B Workshop Consensus Items as set forth in Section 9.3.

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 2016.
2. Approve two energy procurement events scheduled for Spring 2017 and Fall 2017. The energy amounts to be procured in the spring will be based on the updated March 15, 2017 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 (and capacity for Ameren Illinois) amounts to be procured in the fall will be based on the July 15, 2017 updated base 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. The March 15, 2017 and the July 15, 2017 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. In the event that the parties do not reach consensus on an updated load forecast required in Item 2 above, then the most recent consensus load forecast will be used for the applicable procurement event. If the Parties are unable to reach consensus on either of the updated load forecasts required in Item 2 above, then the July 2016 load forecast will be used for the applicable procurement event.

4. Approve procurement by ComEd, Ameren Illinois, and MidAmerican of capacity, network transmission service and ancillary services from their respective RTO.
5. Approve a Fall 2017 capacity procurement for Ameren Illinois.
6. Approve pro-rata curtailment of ComEd and/or Ameren Illinois' 2010 long-term power purchase agreements for renewable energy in the unlikely event that the updated March 2017 load forecast indicates that such a curtailment is necessary. This forecast will form the basis for pro-rata curtailment of long term renewable contracts assuming consensus is reached among the parties identified in Item 3 above. Otherwise, the July 2016 forecast will form the basis for curtailment.
7. Approve a Spring 2017 procurement of RECs using the renewable resources budget for the prompt delivery year to allow the utilities to meet their RPS requirements other than for distributed generation for Ameren Illinois and ComEd. The volume for the procurement will be determined based upon the "Remaining Target" quantities resulting from the utilities' March, 2017 load forecasts and limited to the funds available according to the utilities' updated renewable resource budgets.
8. Approve two procurements of distributed generation RECs using the Renewable Resources Budget for MidAmerican, and using already collected hourly ACP funds for Ameren Illinois and ComEd, minus the total dollar value committed from prior distributed generation REC contracts. For Ameren Illinois and ComEd, the budget will also reflect any hourly ACP funds committed to the purchase of curtailed RECs stemming from the 2010 long-term power purchase agreements.
9. Approve specific consensus items from the 2016 energy efficiency stakeholder workshops related to the implementation of Section 16-111.5B of the PUA that are set forth in Section 9.3.
10. Approve the Section 16-111.5B incremental energy efficiency programs identified in Chapter 9.

The Illinois Power Agency respectfully files its 2017 Procurement Plan, which the IPA believes is compliant with all applicable laws, for Commission approval and requests approval of the specific action items listed above.

2 Legislative/Regulatory Requirements of the Plan

This Section of the 2017 Procurement Plan describes the legislative and regulatory requirements applicable to the Agency's annual Procurement Plan, including compliance with previous Commission Orders. A Regulatory 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.

2.1 IPA Authority

The Illinois Power Agency ("IPA" or "Agency") was established in 2007 by Public Act 95-0481 in order 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"),[10] benefit from retail and wholesale competition. The objective of the Act was to improve the process to procure electricity for those customers.[11] 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."[12] The General Assembly also articulated "investment in energy efficiency and demand-response measures, and to support development of clean coal technologies and renewable resources" as additional goals.[13]

Each year, the IPA must develop a "power procurement plan" and conduct a competitive procurement process to procure supply resources as identified in the final procurement plan, as approved by the Commission pursuant to Section 16-111.5 of the Public Utilities Act ("PUA").[14] The purpose of the power procurement plan is to secure the electricity commodity 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.[15] The Illinois Power Agency Act ("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"[16] and "Procurement Administrator."[17] The Illinois Commerce Commission ("ICC" or "Commission") is tasked with approval of the plan and monitoring of the procurement events through a Commission-hired "Procurement Monitor."[18]

2.2 Procurement Plan Development and Approval Process

Although the elements of 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 2017 Procurement Plan began on July 15, 2016. 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.

Next, the IPA prepares a draft Procurement Plan. On August 15, 2016, that Plan was made available for public review and comment. The Public Utilities Act provides for a 30-day comment period starting on the day the

[10] 220 ILCS 5/16-111.5(a).
[11] 20 ILCS 3855/1-5(2)-(4).
[12] 20 ILCS 3855/1-5(1).
[13] 20 ILCS 3855/1-5(4).
[14] 20 ILCS 3855/1-20(a)(2), 1-75(a).
[15] 20 ILCS 3855/1-20(a)(1). MidAmerican elected to participate in the 2016 Procurement Plan and will continue to participate in the 2017 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.")
[16] 20 ILCS 3855/1-75(a)(1).
[17] 20 ILCS 3855/1-75(a)(2).
[18] 220 ILCS 5/16-111.5(b), (c)(2).

IPA releases its draft plan. The 2017 Plan comment period concluded on September 14, 2016. During the 30-day comment period, the Agency held public hearings within each participating utility's service area for the purpose of receiving public comment on the procurement plan.[19] Written comments were received from Ameren Illinois, Carbon Solutions Group, Citizens Utility Board, ComEd, the Environmental Law and Policy Center, Exelon Generation, the Staff of the Illinois Commerce Commission, the Office of the Attorney General of Illinois, the Illinois Solar Energy Association, the Illinois Solar Energy Association's Business Members, MidAmerican, the Natural Resources Defense Council, Power TakeOff, a collection of Renewables Suppliers, the Illinois Chapter of the Sierra Club, SRECTrade, and Wind on the Wires.

Objections to this Plan must be filed with the Commission within five days after the filing of the Plan.[20] Typically, the presiding Administrative Law Judge sets the dates for Responses and Replies to Objections shortly after the docket opens, and for this proceeding, the Agency has included a proposed briefing schedule with its petition accompanying the filing of this Plan. The Commission must enter an order confirming or modifying the Plan within 90 days after it is filed by the IPA.[21] With a filing date for the 2017 Plan of September 27, 2016, this year's deadline for approval will fall on December 27, 2016.[22]

Under the Public Utilities Act, 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."[23]

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 (such as renewable/clean coal purchase requirements or mandates from previous Commission Orders). 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.[24] 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.[25] 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,[26] 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.[27]
- 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

[19] 220 ILCS 5/16-111.5(d)(2). Public hearings on the draft 2017 Plan took place on September 6 in Springfield, September 7 in Chicago, and September 9 in Moline. No comments were offered by the public at any of the three public hearings.

[20] 220 ILCS 5/16-111.5(d)(3).

[21] Id.

[22] Commission approval occurs through the entry of an official administrative order approving the Plan by the Commission at a public meeting (regular open meeting, bench session, etc.). The Commission's last public meeting for 2016 is currently a regular open meeting scheduled for December 20, 2016, with a meeting also scheduled in the week prior for December 14, 2016.

[23] 220 ILCS 5/16-111.5(d)(4).

[24] 220 ILCS 5/16-111.5(b)(1)(i)-(iv).

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

[26] 220 ILCS 5/16-111.5(b)(3).

[27] 220 ILCS 5/16-111.5(b)(i), (b)(iii).

generating resources.[28] 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.[29]

- Detail the proposed term structures for each wholesale product type included in the portfolio of products.[30]
- 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.[31] 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. [32]
- Include renewable resource and 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."[33] This listing has been understood by the Commission to be non-exhaustive and non-static.[34] 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."[35]

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,[36] 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.[37] 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

[28] 220 ILCS 5/16-111.5(b)(3)(iv).
[29] Id.
[30] 220 ILCS 5/16-111.5(b)(3)(v).
[31] 220 ILCS 5/16-111.5(b)(3)(vi).
[32] 220 ILCS 5/16-111.5(b)(4).
[33] 220 ILCS 5/16-111.5(b)(3)(iv).
[34] 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").
[35] Id.
[36] While not adopting ICEA'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").
[37] *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).

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."[38]

2.5 Renewable Energy Resources

2.5.1 Renewable Portfolio Standard

The General Assembly has acknowledged the importance of including cost-effective renewable resources in a diverse electricity portfolio.[39] "Renewable energy resources" is defined in the Illinois Power Agency Act as (1) energy and its associated renewable energy credit or (2) renewable energy credits alone from qualifying sources such as wind, solar thermal energy, photovoltaic cells and panels, biodiesel, and other generating technologies as identified in the IPA Act.[40] Section 1-75(c)(1) of the IPA Act requires that a minimum percentage of each utility's total supply to serve the load of eligible retail customers shall be generated from cost-effective renewable energy resources; by June 1, 2017, that requirement is at least 13.0% of each utility's total supply, with the requirement increasing by 1.5% each year until reaching 25% in 2025.[41]

Section 1-75(c)(1) of the IPA Act also features sub-target goals for the procurement of renewable energy resources by specific generating technologies. For the current (2017) Procurement Plan, to the extent cost-effective resources are available, the IPA is directed to procure at least 75% of renewable energy resources used to meet overall renewable energy resource requirements from wind generation, 6% from photovoltaics, and 1% from distributed renewable energy generation devices.[42] Renewable energy resources procured from distributed generation devices to meet this requirement may also count towards the required percentages for wind and solar photovoltaics.[43] Stated differently, if the IPA procures the required 1% distributed generation ("DG") renewable energy resources from photovoltaics, those procured resources may also count toward the 6% solar photovoltaics sub-target, leaving 5% solar photovoltaics to be procured from other sources.

In both Docket No. 14-0588 and Docket No. 15-0541 (approving the Agency's 2015 and 2016 Plans), the Commission confronted the question of whether, given that the overall renewable energy resource requirements for the upcoming delivery year were already met (via existing long-term contracts), procurements should still be conducted to satisfy the sub-target percentage goals specific to generating technologies.[44] In both proceedings, the Commission approved the Agency's proposal to conduct a procurement of renewable energy credits specifically from photovoltaic systems to meet those sub-targets over the objections of ComEd and Ameren Illinois (who viewed the procurement as "unnecessary" given that overall REC procurement targets were met), stating that "the plain language of Section 1-75(c)(1) requires technology-specific targets by dates certain."[45]

Section 1-75(c)(1) sets renewables targets and technology-specific sub-targets based on "a minimum percentage of each utility's total supply to serve the load of eligible retail customers, as defined in Section 16-111.5(a) of the Public Utilities Act."[46] With respect to ComEd and Ameren Illinois, "each utility's total supply

[38] Docket No. 14-0588, Final Order dated December 17, 2014 at 156.
[39] 20 ILCS 3855/1-5(5)-(6).
[40] 20 ILCS 3855/1-10. See also Docket No. 10-0563, Final Order dated December 21, 2010 at 83 ("Section 1-10 defines 'renewable energy resources' as either energy and its associated renewable energy credit or renewable energy credits from renewable energy, such as wind or solar thermal energy. As noted in Section 1-10 a REC is a renewable energy resource and therefore fully meets the requirement of Section 1-20 of the IPA Act requiring the procurement of renewable energy.")
[41] 20 ILCS 3855/1-75(c)(1).
[42] Id.
[43] Id.
[44] See generally Docket No. 14-0588, Final Order dated December 17, 2014 at 286 (and associated discussion); Docket No. 15-0541, Final Order dated December 16, 2015 at 126-127.
[45] Docket No. 15-0541, Final Order dated December 16, 2015 at 126-127. Alternatively, in past procurement plan proceedings, the Commission has also approved Agency proposals to not conduct renewable resource procurements despite sub-targets not scheduled to be met due to concerns about the availability of renewable resource budget funds or the scarce amount of resources required to be procured relative to the procurement's administrative costs. (See generally Docket Nos. 12-0544, 13-0546).
[46] 20 ILCS 3855/1-75(c)(1).

to serve the load of eligible retail customers" is addressed through the IPA's procurement planning process. Alternatively, MidAmerican "may elect to procure power and energy for all or a portion of its eligible Illinois retail customers in accordance with the applicable provisions set forth in this Section and Section 1-75 of the Illinois Power Agency Act,"[47] raising the question of whether the renewables targets enumerated in Section 1-75(c) automatically apply to MidAmerican's entire eligible retail customer load, or only to that portion of its eligible retail customer load for which the IPA develops its procurement plan. The Commission settled this issue in Docket No. 15-0541, stating that "the statutes should be interpreted such that the renewable resources targets should only relate to that portion of the 'total supply' procured for MidAmerican's jurisdictional eligible retail customers that is included in the 2016 Procurement Plan."[48]

All renewable energy resources procured, including those to meet sub-target requirements, must still be "cost-effective" under the law. The IPA Act's definition of "cost-effective" has two key features: first, for different renewable resources, the Procurement Administrator creates "benchmarks based on market prices for renewable energy resources in the region" against which all bids are measured.[49] No bid exceeding the established confidential benchmark price may be recommended for procurement. Second, and in addition to the benchmarks, the total cost of renewable energy resources procured for any single year shall be reduced by an amount necessary to limit the annual estimated average net increase due to the costs of these resources to no more than the greater of:

- 2.015% of the amount paid per kilowatt-hour by eligible retail customers during the year ending May 31, 2007; or
- The incremental amount per kilowatt-hour paid for these resources in 2011.[50]

These values are now fixed for Ameren Illinois, ComEd, and MidAmerican, The greater of the two is the 2007 calculation, which constitutes 0.18054 ¢/kWh for Ameren Illinois, 0.18917 ¢/kWh for ComEd, and 0.12415 ¢/kWh for MidAmerican. When these values are multiplied against a utility's forecast eligible retail customer load, it creates a budget amount commonly referred to as that utility's "renewable resources budget," which constitutes the maximum that may be spent on renewable resource procurement in a given year under Section 1-75(c)(1) of the IPA Act (additional money may be spent from the renewable energy resources fund for from alternative compliance payments paid by hourly rate customers).

Cost-effective renewable energy resources are subject to geographic restrictions. The IPA must first procure from resources located in Illinois or in states that adjoin Illinois.[51] If cost-effective renewable energy resources are not available in Illinois or adjoining states, the IPA must seek cost-effective renewable energy resources from "elsewhere."[52]

The IPA's 2016 Plan called for the pre-authorization from the Commission of a curtailment of long-term renewable PPAs, pursuant to the language of the contract, should the Spring 2016 load forecasts indicate that the eligible retail customer rate cap would be exceeded.[53] As discussed in later chapters, with significant amounts of load having switched back to ComEd supply and a modest amount of load switched back to Ameren Illinois supply, the likelihood that existing long-term power purchase agreements may need to be

[47] 220 ILCS 5/16-111.5(a) (emphasis added).
[48] Docket No. 15-0541, Final Order dated December 16, 2015 at 131.
[49] 20 ILCS 3855/1-75(c)(1).
[50] 20 ILCS 3855/1-75(c)(2)(E).
[51] 20 ILCS 3855/1-75(c)(3).
[52] Id.
[53] This process involves the IPA, Commission Staff, the utilities, and the Commission's Procurement Monitor reviewing and approving the spring load forecast used to determine whether curtailment is necessary. In past procurement plan approval proceedings, this approach was contested by parties who contended that the Spring load forecast approval process should be open to stakeholder comment and require an additional step for Commission approval. In Docket No. 15-0541, the Commission found that the existing process "has worked well and has led to favorable results in the procurement process" and that those parties repeatedly challenging that process were "Collaterally Estopped from presenting this argument in future procurement dockets." Docket No. 15-0541, Final Order dated December 16, 2015 at 79.

curtailed for the 2017-2018 delivery year is very low in the case of ComEd and modest in the case of Ameren Illinois.[54] MidAmerican has not entered into any long-term contracts of this nature.

As referenced above, in addition to funds from eligible retail customers, alternative compliance payments collected by the utility from customers taking service under the utility's hourly pricing tariff "increase [IPA] spending on the purchase of renewable energy resources to be procured by the electric utility for the next plan year."[55] As part of the 2015 and 2016 Plans, the existing balances of these funds were committed to procure distributed generation renewable energy resources under 5-year contracts, with the balance of funds available for the distributed generation procurement reduced by any amounts necessary to be spent on RECs from long-term renewable PPA holders that could not be purchased by eligible retail customers due to Commission-authorized curtailments necessitated by the statutory 2.015% rate impact cap.[56]

2.5.2 Distributed Generation Resources Standard

As noted above, within the Renewable Portfolio Standard are sub-targets for the procurement of wind (75%), photovoltaics (6%), and distributed generation (1%). Procurement of renewable energy resources from distributed renewable energy generation devices is to be conducted on an annual basis through multi-year contracts of no less than five years, and shall consist solely of renewable energy credits.[57]

A generation source is considered a "distributed renewable energy generation device" ("DG") under the IPA Act if it is:

- Powered by wind, solar thermal energy, photovoltaic cells and panels, biodiesel, crops and untreated and unadulterated organic waste biomass, tree waste, and hydropower that does not involve new construction or significant expansion of hydropower dams;
- Interconnected at the distribution system level of either an electric utility, alternative retail electric supplier, municipal utility, or a rural electric cooperative;
- Located on the customer side of the customer's electric meter and is primarily used to offset that customer's electricity load; and is
- Limited in nameplate capacity to no more than 2,000 kW.[58]

To the extent available, half of the renewable energy resources procured from distributed renewable energy generation shall come from devices of less than 25 kW in nameplate capacity.[59]

The IPA's 2015 Plan featured the first distributed generation-specific procurement approved by the Commission, conducted using hourly customer alternative compliance payment funds previously collected by Ameren Illinois and ComEd, culminating in a procurement held on October 14, 2015.[60] A similar proposal was included in the 2016 Plan, culminating in a second DG procurement event on June 23, 2016 (which included the procurement of DG RECs for MidAmerican as well as Ameren Illinois and ComEd). Resulting contracts from both procurements are for 5 years and may be from any qualifying distributed generation technology. As renewable energy resources procured from distributed generation devices may also count towards the required percentages for wind and solar photovoltaics, the Agency will track the attributes of systems under contract for future REC deliveries as a result of the recent DG procurements and use that information to inform the amount to be procured in future renewables, wind, photovoltaics, and distributed generation

[54] See Section 3.2.3 for further discussion of Ameren Illinois' "low" scenario load forecast.
[55] 20 ILCS 3855/1-75(c)(5).
[56] Docket No. 14-0588, Final Order dated December 17, 2014 at 6; Docket No. 15-0541, Final Order dated December 16, 2015 at 10. As curtailments were ultimately not necessary for the 2015-2016 and 2016-2016 delivery years, no funds will be spent on curtailed RECs.
[57] 20 ILCS 3855/1-75(c)(1).
[58] 20 ILCS 3855/1-10.
[59] 20 ILCS 3855/1-56(b).
[60] For background on the assessment and collection of hourly customer alternative compliance payments, see 20 ILCS 3855/1-75(c)(5). Also, as MidAmerican had not elected to participate in the 2015 Procurement Plan, this initial DG procurement was conducted only for ComEd and Ameren Illinois.

procurements (including procurements for the 2017-2018 delivery year). Chapter 8 contains additional information on how the Agency plans to address the distributed generation and other technology-specific sub-target goals.

2.5.3 Renewable Energy Resources Fund

Separate from the renewable energy procurements approved as part of the Agency's annual procurement plan are procurements made by the IPA from the Renewable Energy Resources Fund ("RERF"). Created through Section 1-56 of the Illinois Power Agency Act, the RERF is a special fund in the Illinois State Treasury administered by the Illinois Power Agency to procure renewable energy resources.[61] Unlike with procurements made to satisfy the requirements of Section 1-75(c) of the IPA Act, procurements made from the RERF are not proposed as part of the Agency's annual plan and do not require Commission approval, and the resulting counterparty for such procurements is the State of Illinois (and not the utilities).[62] Resources procured using the RERF thus cannot be used to meet the utilities' Section 1-75(c) renewable energy resources procurement targets.

The RERF is funded through payments made by Alternative Retail Electric Suppliers ("ARES") to satisfy statutory renewable energy resource procurement obligations manifest in Section 16-115D of the Public Utilities Act.[63] The RERF does not consist of payments made by customers taking supply from their electric utility. Instead, for customers taking supply from an ARES, the ARES is responsible for making an alternative compliance payment for no less than 50% of its compliance obligation,[64] with its payment rate determined by results from the procurement of renewable energy resources using the renewable resources budget (including any previously-entered into contracts, such as the LTPPAs).[65] These alternative compliance payments ("ACPs") are generally made in conjunction with an ARES's self-procurement of the remainder of its renewable energy resource obligation to meet compliance with state's renewable energy portfolio standard.[66]

In recognition of the constraints present in attempting to conduct procurements from the RERF without more express statutory authorization,[67] Public Act 98-0672 created new subsection 1-56(i) of the IPA Act requiring the Illinois Power Agency to develop a plan for conducting a supplemental procurement of renewable energy credits from solar photovoltaics ("SRECs") using up to $30 million from the RERF.[68] The IPA's Supplemental Photovoltaic Procurement Plan was filed with the Commission on October 28, 2014 and approved on January 21, 2015. As called for in the Supplemental Plan, the IPA conducted its first supplemental photovoltaic procurement in May 2015 with a budget of $5 million, its second procurement in November 2015 with a budget of $10 million, and its third procurement in March 2016 with a budget of $15 million.[69] All three procurements resulted in the commitment of the entirety of the respective procurement budgets.

2.6 Energy Efficiency Programs or Measures

Section 16-111.5B of the PUA outlines requirements related to including new or expanded cost-effective energy efficiency programs in the Procurement Plan. The Procurement Plan must include an assessment of opportunities to expand programs under the utilities' existing Commission-approved energy efficiency plans

[61] 20 ILCS 3855/1-56(a).
[62] See generally Docket No. 12-0544, Final Order dated December 19, 2012 at 112-113; Docket No. 15-0541, Final Order dated December 16, 2015 at 147.
[63] 220 ILCS 5/16-115D(d)(4).
[64] 220 ILCS 5/16-115D(b).
[65] 220 ILCS 5/16-115D(d)(1).
[66] In past years, the vast majority of ARES have chosen to pay no more than the minimum percentage (50%) in alternative compliance payments, relying on self-procurement for the remainder.
[67] For further discussion of these constraints, see the IPA's Supplemental Photovoltaic Procurement Plan at 3-4.
[68] See 20 ILCS 3855/1-56(i).
[69] Information about the results of the IPA's supplemental photovoltaic procurements may be found at https://www.ipa-energyrfp.com/supplemental-pv-procurement-section/.

or to implement additional cost-effective energy efficiency programs or measures.[70] To assist in this effort, the utilities are required to provide, along with their load forecasts, an "assessment of cost-effective energy efficiency programs or measures that could be included in the Procurement Plan."[71] This assessment is required to include the following:

- A comprehensive energy efficiency potential study for the utility's service territory that was completed within the past 3 years.[72]
- Beginning in 2014, the most recent analysis submitted pursuant to Section 8-103A of the PUA and approved by the Commission under subsection (f) of Section 8-103 of the PUA.[73]
- Identification of new or expanded cost-effective energy efficiency programs or measures that are incremental to those included in energy efficiency and demand-response plans approved by the Commission pursuant to Section 8-103 and that would be offered to all retail customers whose electric service has not been declared competitive under Section 16-113 of the PUA and who are eligible to purchase power and energy from the utility under fixed-price bundled service tariffs, regardless of whether such customers actually do purchase such power and energy from the utility.[74]
- Analysis showing that the new or expanded cost-effective energy efficiency programs or measures would lead to a reduction in the overall cost of electric service.[75]
- Analysis of how the cost of procuring additional cost-effective energy efficiency measures compares over the life of the measures to the prevailing cost of comparable supply.[76]
- An energy savings goal, expressed in megawatt-hours, for the year in which the measures will be implemented.[77]
- For each expanded or new program, the estimated amount that the program may reduce the agency's need to procure supply.[78]

Both Ameren Illinois and ComEd have provided this information, which is included in the Appendices to this Procurement Plan along with their load forecast information. Alternatively, because MidAmerican does not fall under the purview of Section 8-103 of the PUA,[79] many of the requirements of Section 16-111.5B are not applicable to it; similar to an approach taken with the development of the 2016 Plan (and approved by the Commission in Docket No. 15-0541), MidAmerican has instead provided this information to the extent applicable and offered a statement regarding inapplicability where it is not.[80]

These assessments were delivered to the IPA on July 15, 2016 to aid the Agency in the development of its 2017 Procurement Plan. The PUA requires the Agency to include in its Procurement Plan those energy efficiency programs and measures that it determines are cost-effective, and the utilities are directed to factor in the associated energy savings to the load forecast.[81] If the Commission approves the procurement of this additional efficiency, it shall reduce the amount of power to be procured under the Procurement Plan and shall direct the utility to undertake the procurement of the efficiency resources.[82]

[70] See 220 ILCS 5/16-111.5B(a)(2). Additionally, pursuant to Section 16-111.5B(a)(1), the Agency's analysis required under Section 16-111.5(b)(2) must provide "the impact of energy efficiency building codes or appliance standards, both current and projected." This information is contained in Appendices to the Plan.
[71] 220 ILCS 5/16-111.5B(a)(3).
[72] 220 ILCS 5/16-111.5B(a)(3)(A).
[73] 220 ILCS 5/16-111.5B(a)(3)(B).
[74] 220 ILCS 5/16-111.5B(a)(3)(C).
[75] 220 ILCS 5/16-111.5B(a)(3)(D).
[76] 220 ILCS 5/16-111.5B(a)(3)(E).
[77] 220 ILCS 5/16-111.5B(a)(3)(F).
[78] 220 ILCS 5/16-111.5B(a)(3)(G).
[79] See 220 ILCS 5/8-103(h) ("This Section does not apply to an electric utility that on December 31, 2005 provided electric service to fewer than 100,000 customers in Illinois"); Docket No. 15-0541, Final Order dated December 16, 2015 at 68.
[80] See Docket No. 15-0541, Final Order dated December 16, 2015 at 67-68.
[81] 220 ILCS 5/16-111.5B(a)(4).
[82] 220 ILCS 5/16-111.5B(a)(5).

For purposes of meeting this statutory requirement, "cost-effective" means that the assessed measures pass the total resource cost test as defined in the IPA Act:[83]

> *"Total resource cost test" or "TRC test" means a standard that is met if, for an investment in energy efficiency or demand-response measures, the benefit-cost ratio is greater than one. The benefit-cost ratio is the ratio of the net present value of the total benefits of the program to the net present value of the total costs as calculated over the lifetime of the measures. A total resource cost test compares the sum of avoided electric utility costs, representing the benefits that accrue to the system and the participant in the delivery of those efficiency measures, as well as other quantifiable societal benefits, including avoided natural gas utility costs, to the sum of all incremental costs of end-use measures that are implemented due to the program (including both utility and participant contributions), plus costs to administer, deliver, and evaluate each demand-side program, to quantify the net savings obtained by substituting the demand-side program or supply resources. In calculating avoided costs of power and energy that an electric utility would otherwise have had to acquire, reasonable estimates shall be included of financial costs likely to be imposed by future regulations and legislation on emissions of greenhouse gases.*[84]

Each year, new issues relating to the implementation of Section 16-111.5B are raised in the Commission proceedings approving the IPA's annual plan. Resolution (or at least further discussion) of these issues is often deferred to workshop processes ordered by the Commission for the months immediately following the conclusion of the docket. Further discussion of the energy efficiency-related workshops required from the Order approving the 2016 Plan and the contested issues addressed therein, as well as the "energy efficiency programs and measures [the IPA] determines are cost-effective" and thus fit for inclusion in this Plan, may be found in Chapter 9.

Additionally, past years' disputes have resulted in a series of Commission-mandated workshops leading to consensus language being reached among stakeholders. Workshops held in 2016 resulting in an updating of those consensus items and the development of new consensus language around previously contested issues. Specific consensus items are included in Chapter 9 (Prior Year Consensus Items) and in the attached SAG Workshop Subcommittee Report (Appendix H), and the IPA expressly requests that such language be approved by the Commission with the intention that it be binding upon the planning of, implementation of, reporting on, and evaluation, measurement, and verification of savings of the energy efficiency programs approved as part of the 2017 Plan, and applied prospectively to inform the requests for proposals developed by the utilities pursuant to Section 16-111.5B(a)(3) for the solicitation of programs to be included in the 2018 Procurement Plan.

2.7 Demand Response Products

The IPA may include cost-effective demand response products in its Procurement Plan. The Procurement Plan must include the particular "mix of cost-effective, demand-response products for which contracts will be executed during the next year, to meet the expected load requirements that will not be met through preexisting contracts."[85] 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.[86] Specifically:

- The demand-response measures must be procured by a demand-response provider from eligible retail customers;

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[83] See 220 ILCS 5/16-111.5B(b) ("For purposes of this Section, the term 'energy efficiency' shall have the meaning set forth in Section 1-10 of the Illinois Power Agency Act, and the term 'cost-effective' shall have the meaning set forth in subsection (a) of Section 8-103 of this Act.); 220 ILCS 5/8-103(a) ("As used in this Section, 'cost-effective' means that the measures satisfy the total resource cost test.").
[84] 20 ILCS 3855/1-10.
[85] 220 ILCS 5/16-111.5(b)(3)(ii).
[86] Id.

- 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;[87]
- The products must provide for customers' participation in the stream of benefits produced by the demand-response products;
- 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;[88]; 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.[89]

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 has approved the utility's AMI Plan.[90] 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.[91] These programs are discussed further in Section 7.4, where demand response resource choices are examined.

2.8 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.[92] As a part of the goal, the Plan must also include electricity generated from clean coal facilities.[93] While there is a broader definition of "clean coal facility" contained in the definition section of the IPA Act,[94] Section 1-75(d) describes two special cases: the "initial clean coal facility"[95] 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").[96] Currently, there is no facility meeting the definition of an "initial clean coal facility," that the IPA is aware of, that has announced plans to begin operations within the next five years.

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 delivery year; that administrative approval and the associated cost recovery mechanism were subsequently appealed, and initially upheld by the Illinois First District Appellate Court.[97] With an appeal still pending before the Illinois Supreme Court, the U.S. Department of Energy announced in February 2015 that federal funding for the project would be suspended.[98] The FutureGen Alliance's Board of Directors "approved a resolution, dated January 6, 2016, ceasing all FutureGen Project development efforts"[99] 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

[87] 220 ILCS 5/16-111.5(b)(3)(ii)(A)-(B).
[88] 220 ILCS 5/16-111.5(b)(3)(ii)(C)-(D).
[89] 220 ILCS 5/16-111.5(b)(3)(ii)(E).
[90] 220 ILCS 5/16-108.6(g).
[91] 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.
[92] 20 ILCS 3855/1-75(d).
[93] 20 ILCS 3855/1-75(d)(1).
[94] 20 ILCS 3855/1-10.
[95] Id.
[96] 20 ILCS 3855/1-75(d)(5).
[97] Commonwealth Edison Co. v. Illinois Commerce Commission, et al., 2014 IL App (1st) 130544, July 22, 2014.
[98] See, e.g., http://www.chicagobusiness.com/article/20150203/NEWS11/150209921/futuregen-clean-coal-plant-is-dead.
[99] Supplemental Brief of Appellee FutureGen Industrial Alliance, Inc. on the Issue of Mootness, dated January 13, 2016, at 1.

Commission's Order approving the 2013 Procurement Plan concerning FutureGen 2.0 sourcing agreements and related authority.[100]

2.9 2015-2016 Legislative Proposals and Related Developments

The 99th Illinois General Assembly (inducted in January 2015 and concluding in January 2017) has seen the introduction of a number of legislative proposals that would significantly change the scope or direction of the Illinois Power Agency's planning and procurement processes. Introduced legislation has included proposals to require the Agency to procure zero-emission credits to provide additional revenue to nuclear power generating facilities in Illinois at risk of closure, increase targets in the state's renewable energy portfolio standard and focus the Agency's efforts on procuring renewable energy resources from newly developed projects, eliminate the Section 16-111.5B mechanism for including incremental energy efficiency programs in IPA procurement plans (while expanding electric utility energy efficiency requirements under Section 8-103 of the PUA), and require the Agency to develop low-income and community solar programs to encourage the development of additional solar photovoltaics projects while providing new pathways for photovoltaic project participation.[101]

As of the filing of this Plan with the Commission, the Agency understands that these proposals—and, possibly, additional proposals that could impact the IPA's procurement authority[102]—are still being actively negotiated by interested stakeholders. Additional legislative session dates for 2016 are currently scheduled for November 15-17 and November 29-December 1, and further dates could be added should unfinished business remain. At this time, it is unclear what changes (if any) will be made to the Agency's powers and responsibilities through legislation in the 99th General Assembly. The Agency will continue to actively track the status of these bills (and provide technical feedback on any such proposals whenever possible) and any other legislation that could change its powers, duties, and objectives.

In addition, on August 3, 2015, the United States Environmental Protection Agency ("U.S. EPA") released its Clean Power Plan rules promulgated pursuant to Section 111(d) of the Clean Air Act. These rules require states to develop strategies intended to reduce carbon dioxide emissions from power plants. On February 9, 2016 the U.S. Supreme Court stayed implementation of the Clean Power Plan pending judicial review.[103] 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 issued in litigation has delayed the timing for the state compliance plan development. Assuming a favorable outcome of the litigation for the U.S. EPA, the development of the Illinois state compliance plan may generate additional legislation of relevance to the Agency.

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[100] Commonwealth Edison Co. v. Illinois Commerce Commission, et al., 2016 IL 118129, May 19, 2016.

[101] The latest and most comprehensive proposal can be found in amendments to Senate Bill 1585, with the most recent amendment to that bill having been filed on May 27, 2016.

[102] See http://www.chicagobusiness.com/article/20160910/ISSUE01/309109997/why-is-nuke-giant-exelon-touting-a-subsidy-for-coal-fired-power

[103] 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.

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."[104] 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, has elected to have the IPA procure incremental amounts of electricity,[105] thus making it also subject to statutorily mandated renewable resources procurement targets for its eligible retail customers in Illinois.[106] 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.[107]

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.*[108]

The forecasts are prepared by the utilities, but the Procurement Plan is ultimately the responsibility of the Illinois Power Agency. The Illinois Commerce 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 report, 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:

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[104] 220 ILCS 5/16-111.5(a).

[105] 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.

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

[107] 220 ILCS 5/16-111.5(b)(1).

[108] 220 ILCS 5/16-111.5(d)(1).

- Ameren Illinois Company Load Forecast for the period June 1, 2017 – May 31, 2022 (See Appendix B)
- Electric Energy Efficiency Compliance with 220 ILCS 5/16-111.5B. This document also contained six Appendices. (See Appendix B. Note, Appendix 4 [Bidder Confirmations] and Appendix 6 [Detailed Bid Analysis] were marked confidential and are not included in Appendix B as part of this Plan.) Ameren Illinois also separately provided to the IPA its most recent energy efficiency potential study, and on a confidential basis, each Section 16-111.5B bid received.
- Spreadsheets of the expected (base), high, and low load forecasts.
- Supplemental spreadsheets detailing the renewable portfolio standard targets and budgets under each scenario, capacity needs under each scenario, and the impact on the expected (base) load forecast of incremental energy efficiency programs. (Summarized in Appendix E)

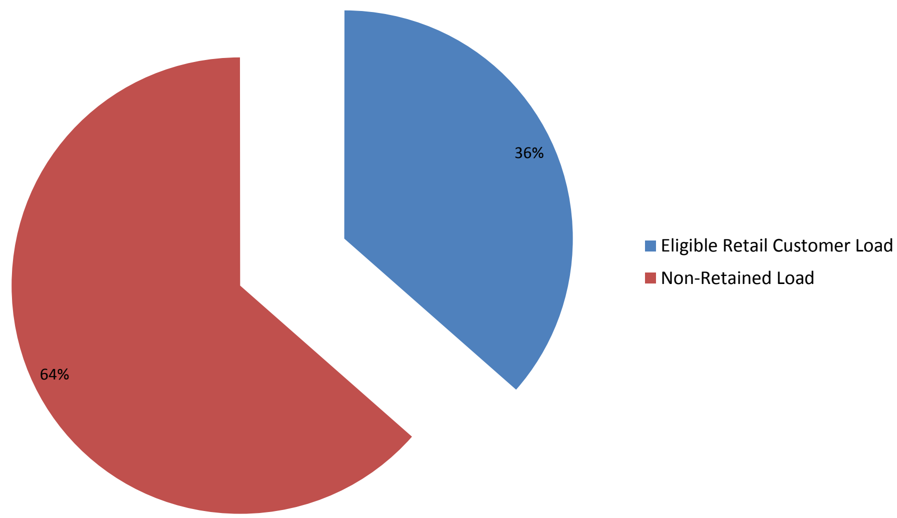
Ameren Illinois uses a combination of statistical and econometric modeling approaches to develop its customer class specific load forecast models. A Statistically Adjusted End-use approach is used for the residential and commercial customer classes. This approach combines the econometric model's ability to identify historic 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 the forecasted annual percentage of usage by eligible retail customer load and non-retained retail customer load.[109]

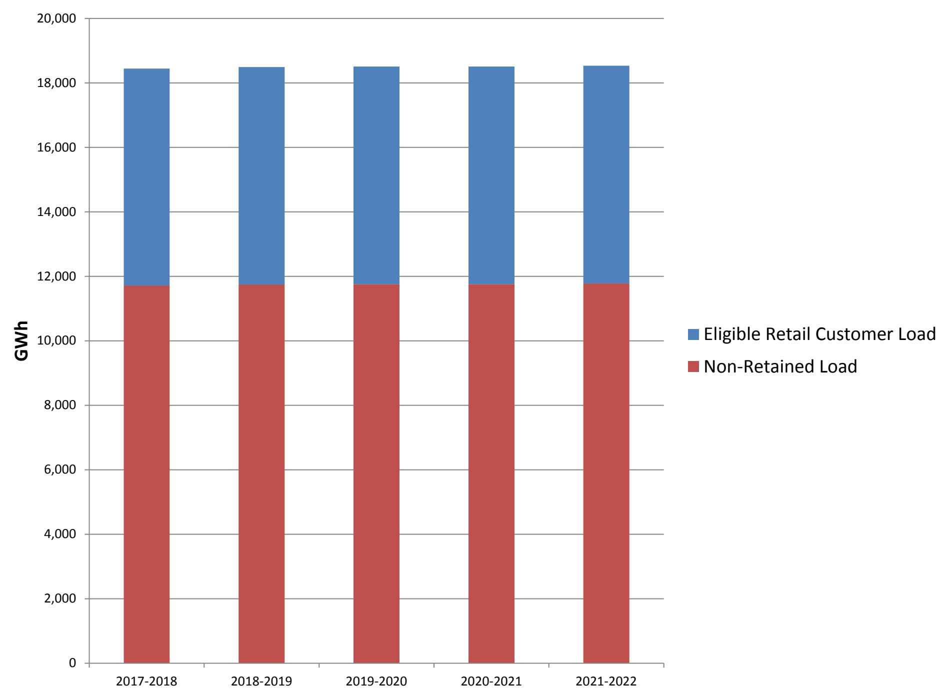
[109] Ameren Illinois assigns load profile classifications at the point of service level and only to points of service that are metered. The classifications are as follows: DS1 – Residential, DS2 – Non-Time of Use Commercial & Industrial with demands less than 150 kW, DS3 – Time of Use Commercial & Industrial with demands between 150 kW and 1,000 kW, DS4 – Time of Use Commercial & Industrial with demands above 1,000 kW, and DS5 – Lighting. The DS3 and DS4 classes are fully competitive, meaning that customers in these classes must receive supply from ARES or Ameren Illinois real time pricing. Customers in the DS1, DS2 and DS5 classes are eligible to take fixed-price supply service from Ameren Illinois or an ARES.

Figure 3-1: Ameren Illinois' Forecast Retail Customer Load Breakdown, Delivery Year 2017-2018



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 by retained/not retained load.

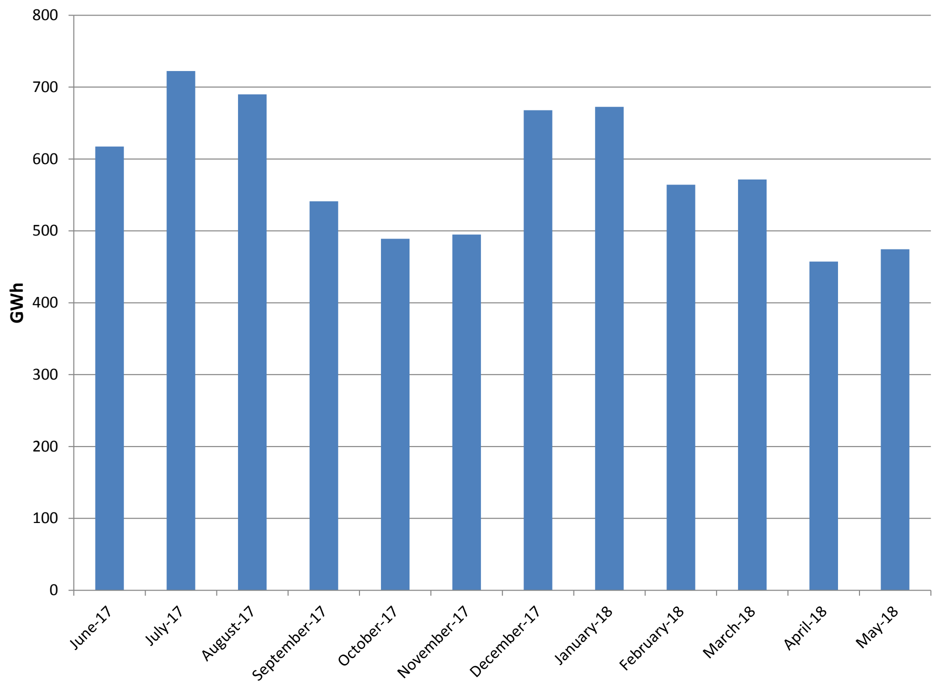
Figure 3-2: Ameren Illinois' Forecast Retail Customer Load by Delivery Year



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), municipal aggregation, or other Alternative Retail Electric Suppliers (“ARES”). Ameren Illinois establishes the current customer switching trend line utilizing actual switching data by customer class. Qualitative judgment is used to make adjustments. The portion of the forecast load attributed to Rider HSS, municipal aggregation, 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 forecast to take bundled supply procured under this Procurement Plan.

Figure 3-3: Ameren Illinois’ Forecast Eligible 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 increase 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 residual from the model fit and the high and low cases are based on a 95% confidence interval.

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: Load Multipliers in Ameren Illinois Excursion Cases

Rate Class	Low Case	High Case
DS1	0.920	1.080
DS2	0.883	1.117
DS5	0.920	1.080

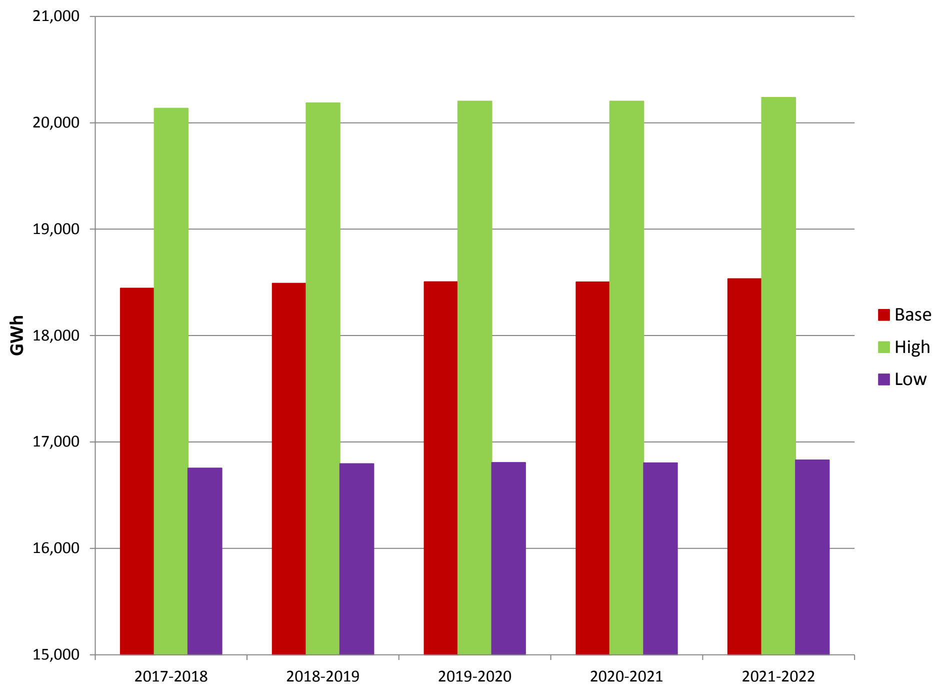
In regression models, residuals indicate the difference between the predicted and actual values. Patterns associated with residuals may indicate the impact of non-specified variables. Because the excursion cases are based on the statistics of the residuals, they reflect the influence of variables not 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 averaged impact of weather, as well as macroeconomics, which is proportionally the same in each hour.

Figure 3-4 shows the base, high, and low case forecasts of Ameren Illinois eligible retail customer load, assuming no switching. The difference between the high, low and base cases show the variation Ameren Illinois attributes to macroeconomics and weather. The low case is about 9% lower than the base case and the high case is about 9% higher than the base case.

Figure 3-4: Ameren Illinois' Eligible Retail Customer Load before Switching in Ameren Illinois' Forecasts



3.2.3 Switching

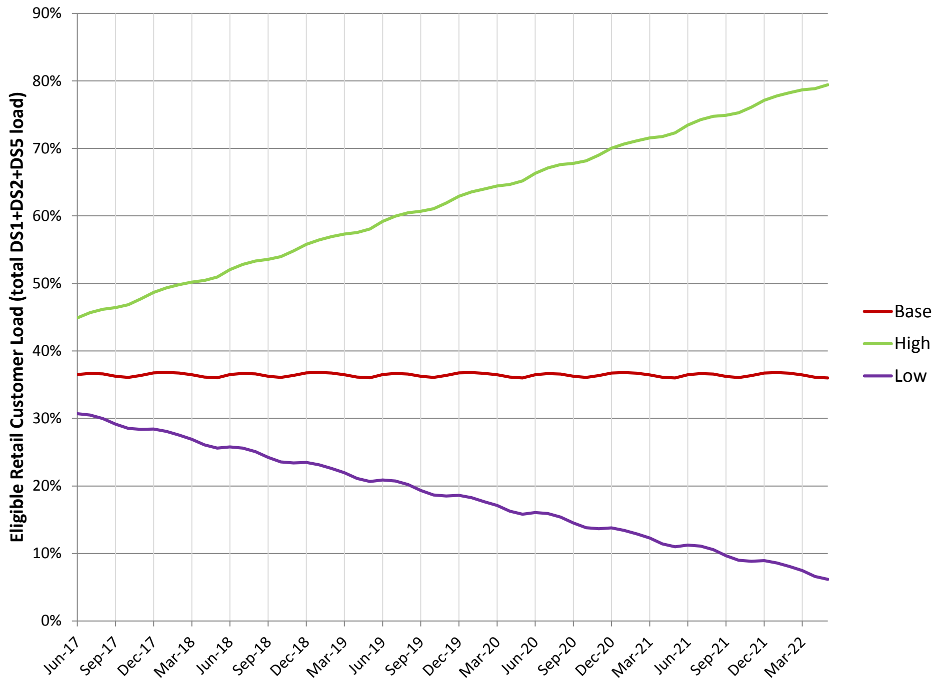
According to Ameren Illinois, customer switching to alternative suppliers, in particular through municipal aggregation, is the greatest driver of load uncertainty. Switching through April 2016 has resulted in approximately 62-65% of residential and small commercial load seeking service from alternative suppliers. Ameren Illinois expects the amount of load supplied by ARES will remain flat across the planning horizon. This expectation is partially based on the fact that the vast majority of municipal aggregation contracts were renewed after their recent expiration. Additionally, according to Table 3-2 presented in the next Section, ARES offerings to individual customers, in general, appear to be higher than the default utility rate; the rates offered by ARES to the aggregated loads may be lower and thus more comparable to the Ameren Illinois default service 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. Residential and small commercial switching rates under the low switching and a corresponding high load scenario are forecasted to be 47% and 50%, respectively, in May 2018, 39% and 43%, respectively, in May 2019, and 18% and 21%, respectively, by the end of the planning horizon.

Conversely, should future Ameren Illinois tariff price 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 72% and 75%, respectively, in May 2018, 76% and 80%, respectively, in May 2019, and 91% and 94%, respectively, by the end of the planning horizon.

The difference in the amount of switching among the three cases is significant. Figure 3-5 shows the retention, that is, the fraction of delivery load in classes DS1, DS2 and DS5 that remains on utility service, for the base, high and low cases.

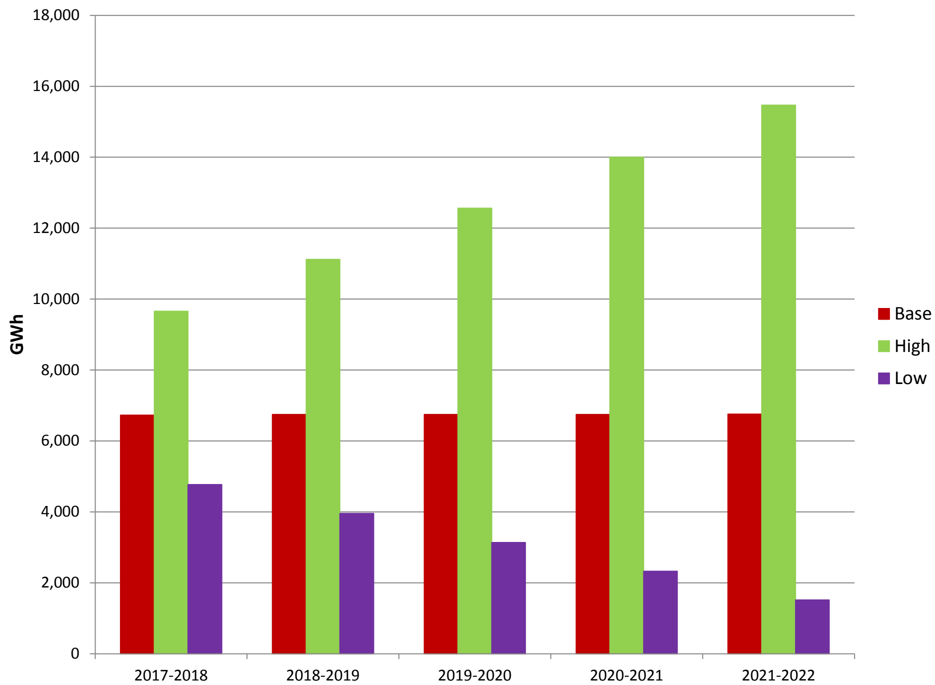
Figure 3-5: Utility Load Retention in Ameren Illinois' Forecasts



As the figure shows, the difference in switching rates among the scenarios grows through the projection horizon. The difference in switching rates is the most significant factor driving the differences among the scenarios.

Figure 3-6 shows the forecasted Ameren Illinois supply obligation in each case.

Figure 3-6: Supply Obligation in Ameren Illinois' Forecasts



3.2.4 Load Shape and Load Factor

Figure 3-7 and Figure 3-8 display the hourly profile of Ameren Illinois supply obligation in each case (relative to the daily maximum load). Figure 3-7 illustrates a summer day and Figure 3-8 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 3-7: Sample Daily Load Shape, Summer Day in Ameren Illinois' Forecasts

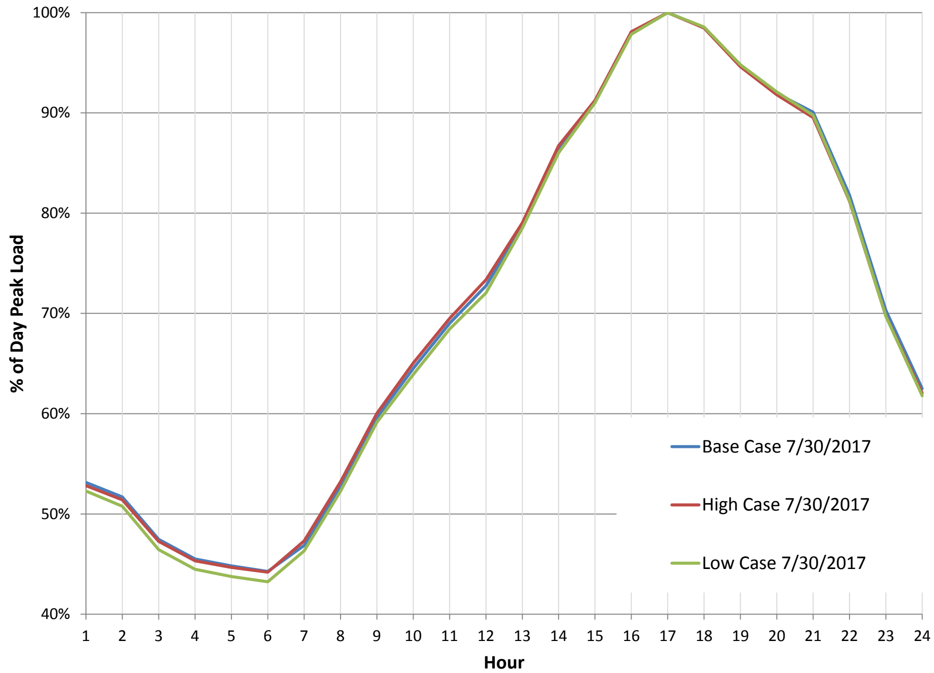
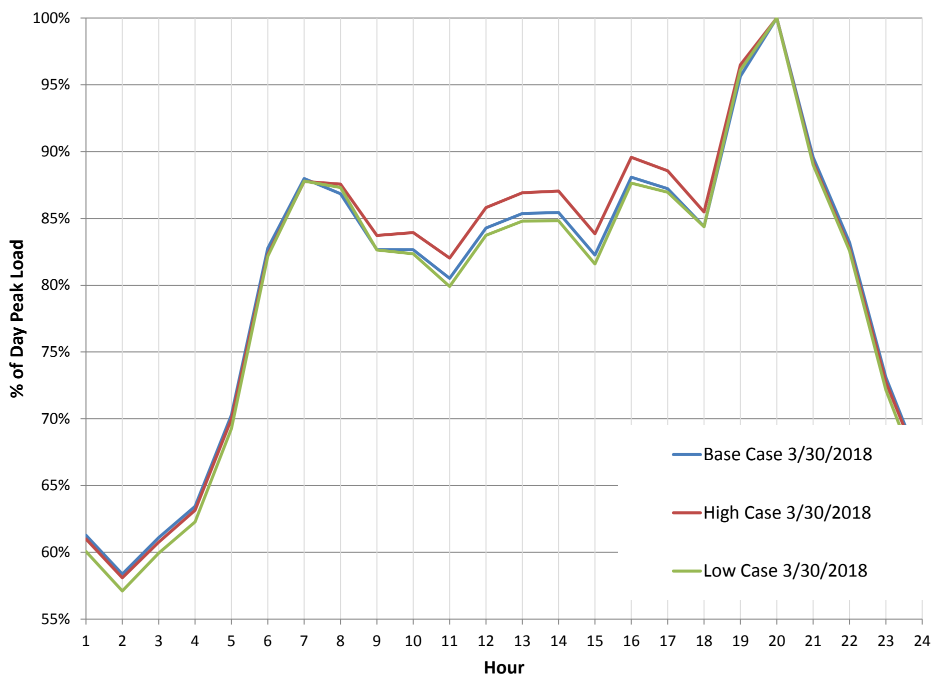
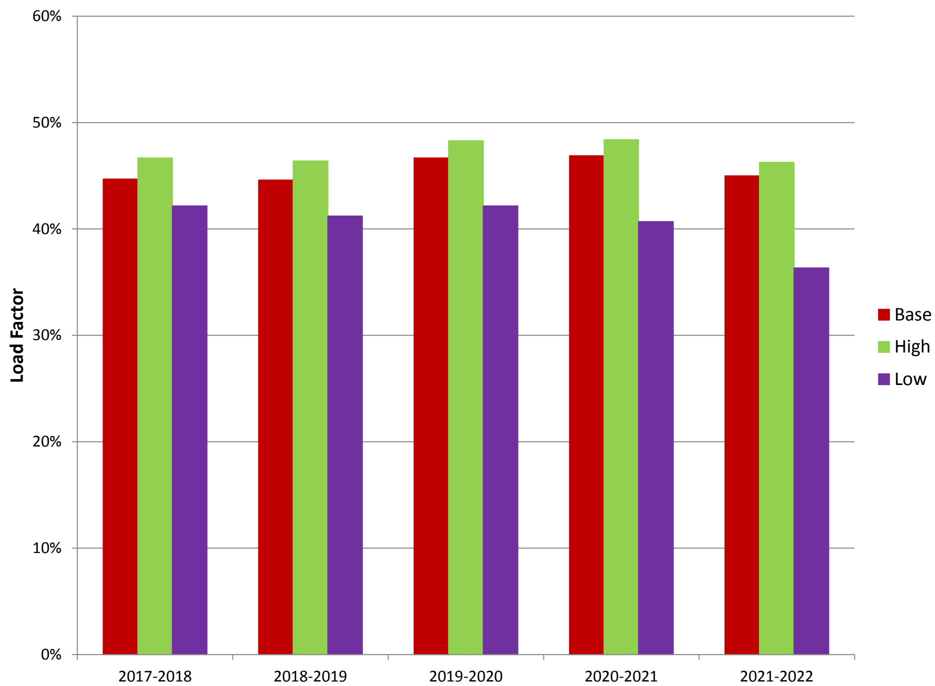


Figure 3-8: Sample Daily Load Shape, Spring Day in Ameren Illinois' Forecasts



One calls a load shape "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 or, in these normalized curves, if the lowest point is well below 1. 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 3-9 shows that the low case has the lowest load factors, while Figure 3-7 and Figure 3-8 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 3-9: Load Factor in Ameren Illinois' Forecasts



3.3 Summary of Information Provided by ComEd

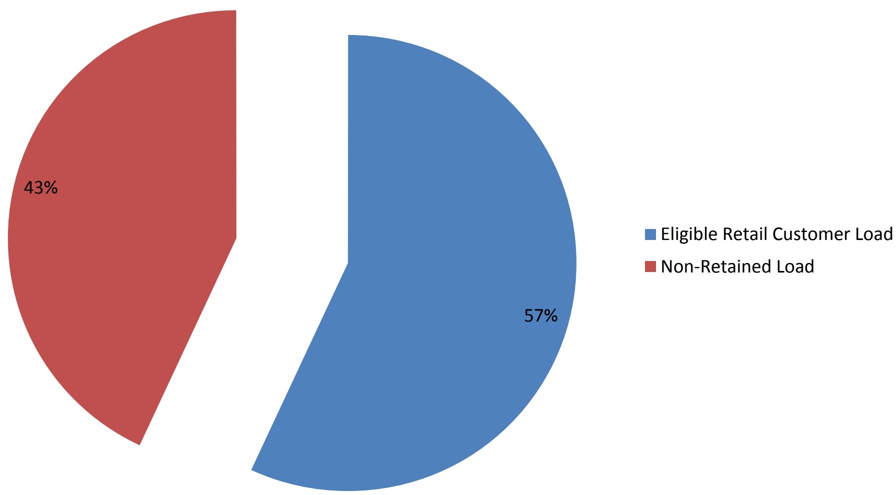
In compliance with Section 16-111-5(d)(1) of the Public Utilities Act, ComEd provided the IPA the following documents for use in preparation of this plan:

- *Load Forecast for Five-Year Planning Period June 2017 – May 2022.* This document also contained Appendices A-D. Four of the Appendices are included in the main document, while one (ComEd Appendix C) with supplemental information on Section 16-111.5B incremental energy efficiency programs was included as five additional separate documents. (See Appendix C. Note, ComEd also provided an additional document entitled, *Third Party Efficiency Program Results of 2016 Bid Review* which was marked confidential and is not included in Appendix C.).
- 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)

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

ComEd did not supply its forecasts for medium and large commercial and industrial customers, whose service has been deemed to be competitive and who therefore cannot be eligible retail customers. Figure 3-10 shows the forecasted annual percentage of usage by eligible retail customer load and non-retained retail customer load.

Figure 3-10: ComEd's Forecast Retail Customer Load Breakdown, Delivery Year 2017-2018



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 3-11, 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 downs the total forecast of residential and small commercial customer load in the same way as Figure 3-10 does for a single year.

Figure 3-11: ComEd's Forecast Retail Customer Load by Delivery Year

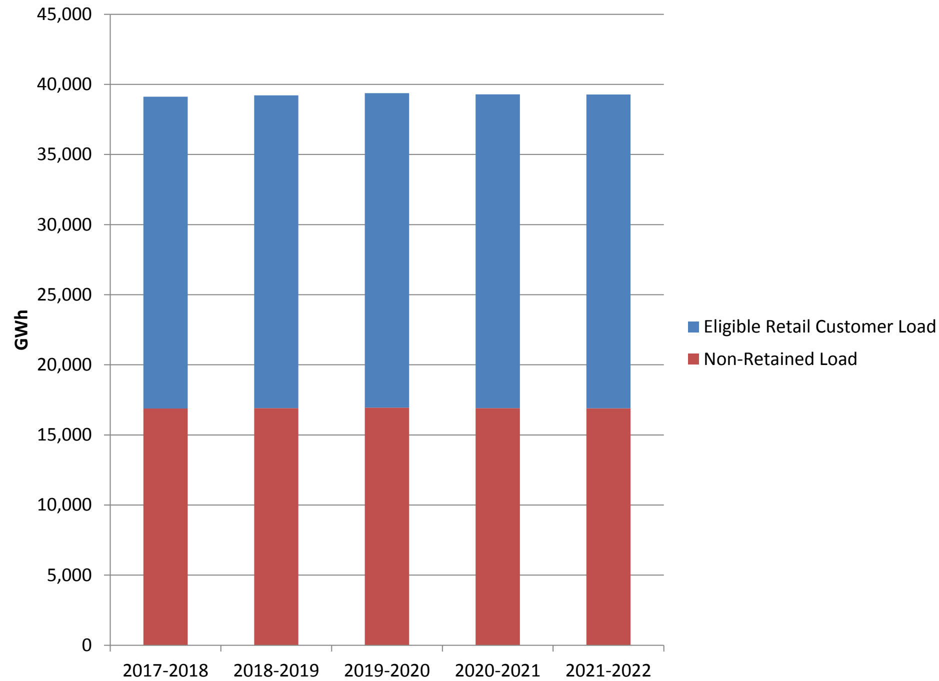
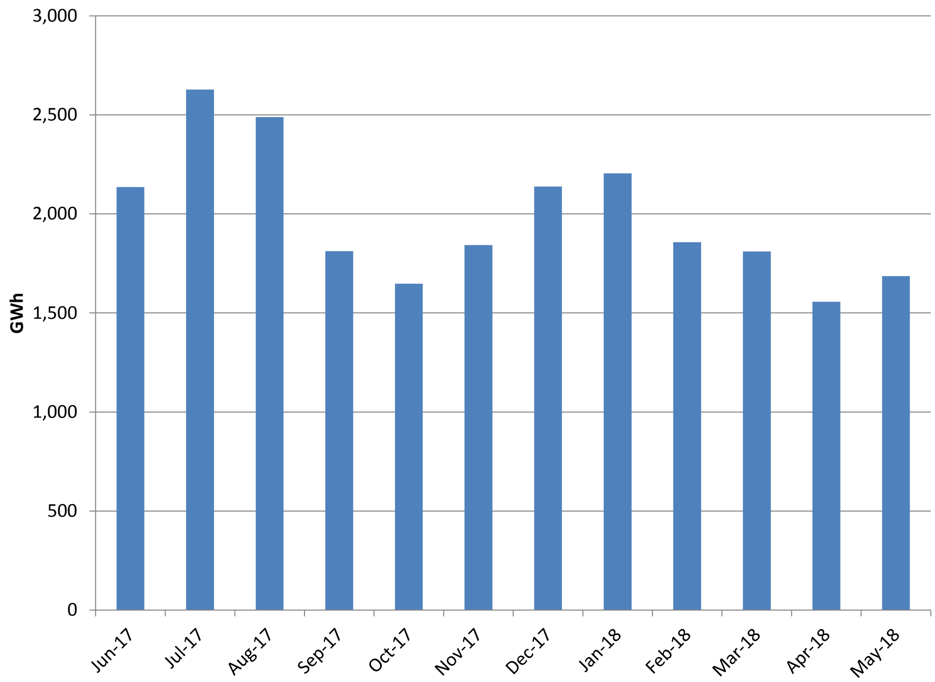


Figure 3-12 provides a monthly breakdown of the base-case forecast of ComEd's eligible retail customer load, that is, the load of customers who are forecast to take bundled supply under this Procurement Plan.

Figure 3-12: ComEd's Forecast Eligible 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

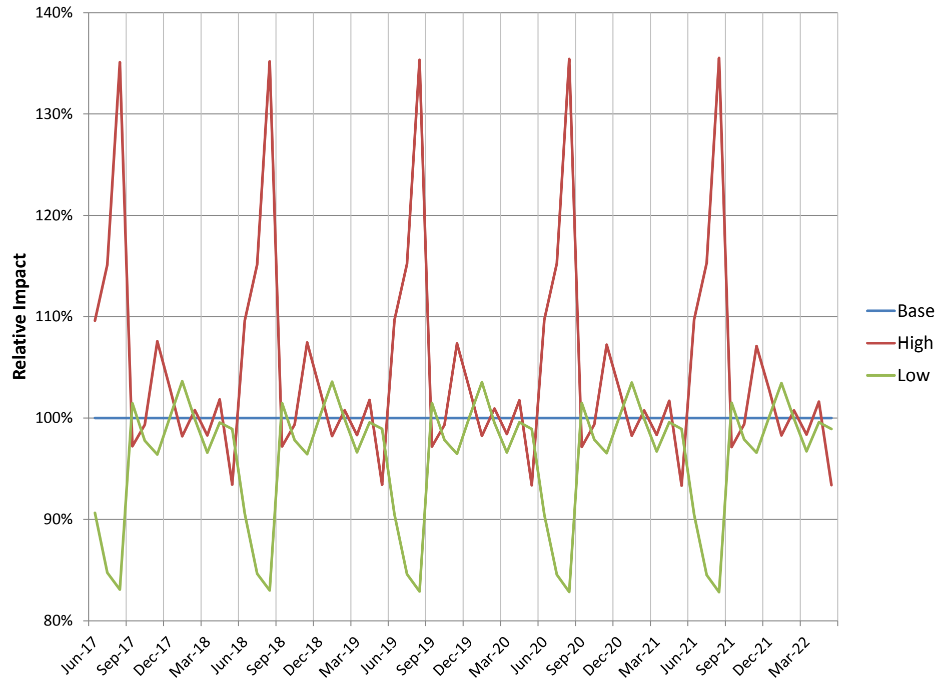
ComEd's base case load forecast is driven by a Zone Model that includes both macroeconomic variables (Gross Metropolitan Product for Chicago and other metropolitan areas within ComEd's service territory, household income) and demographics (household counts). ComEd did not use this model to define "high" 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 load (because the growth rate in the base case is below 2%, 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 weather case on residential and small commercial load, relative to the base case forecast. They are provided as percentages that summarize the hourly impacts of a finer-scale model of the effect of temperature on load. Figure 3-13 shows the impact of weather on load by month. The high and low years are not high and low in every month. There are some months, for example, where the impact of the "high weather" year is less than 1.

Figure 3-13: Weather Impacts in ComEd's Forecasts

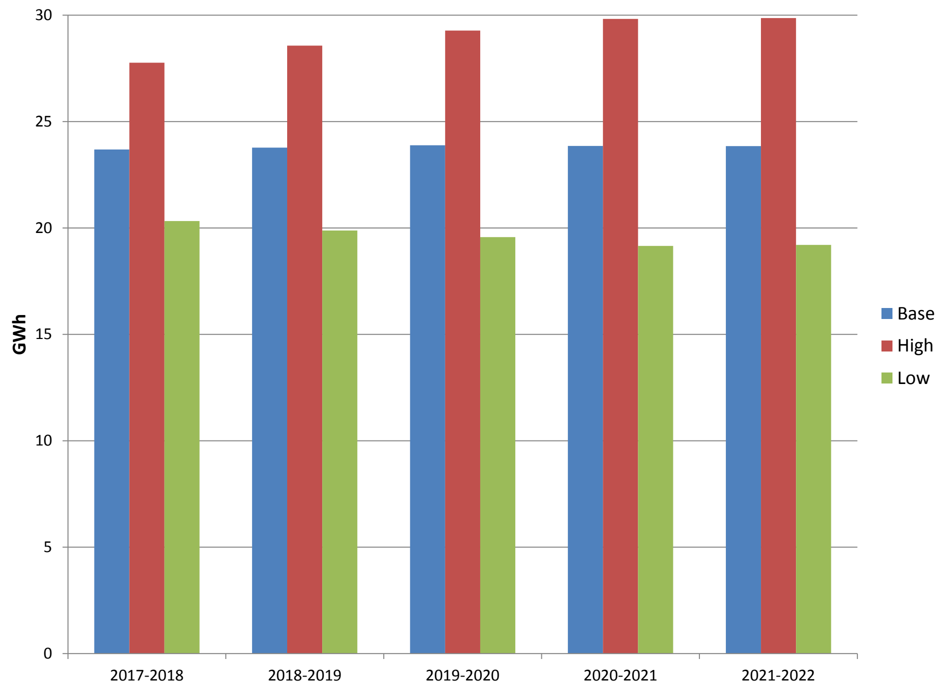


3.3.3 Switching

The high switching (low load) case assumes residential ARES usage to be at 85% (vs. the 60% base case assumption) in the years 2017 and 2018 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 358 communities within the ComEd service territory that had approved aggregation as of April of 2016. That is a very small increase from the 357 communities reported last year. In addition, it is assumed that small commercial switching increases initially by 1.2% and then by another 2.4% over the next 2 years.

The low switching (high load) case assumes additional communities opt out of municipal aggregation in the years 2017 and 2018 such that residential ARES usage declines to approximately 35% in the years 2017 and 2018. This coincides with an initial 1.2% decrease and a further decline by another 2.4% in small commercial switching over the next 2 years. Figure 3-14 shows the forecasted ComEd supply obligation in each case.

Figure 3-14: Supply Obligation in ComEd's Forecasts



3.3.4 Load Shape and Load Factor

Figure 3-15 and Figure 3-16 display the hourly profile of the utility supply obligation in each case (relative to the daily maximum load). Figure 3-15 illustrates a summer day, and Figure 3-16 a spring day. The high case is definitely peakier on a summer day than the base case, and the low case is flatter. During the sample summer day, both the base case and low case are less peaky than the high case; and during the sample spring day, there is no significant difference between the profiles of the high and base cases, but the low case is a slightly peakier.

Figure 3-15: Sample Daily Load Shape, Summer Day in ComEd's Forecasts

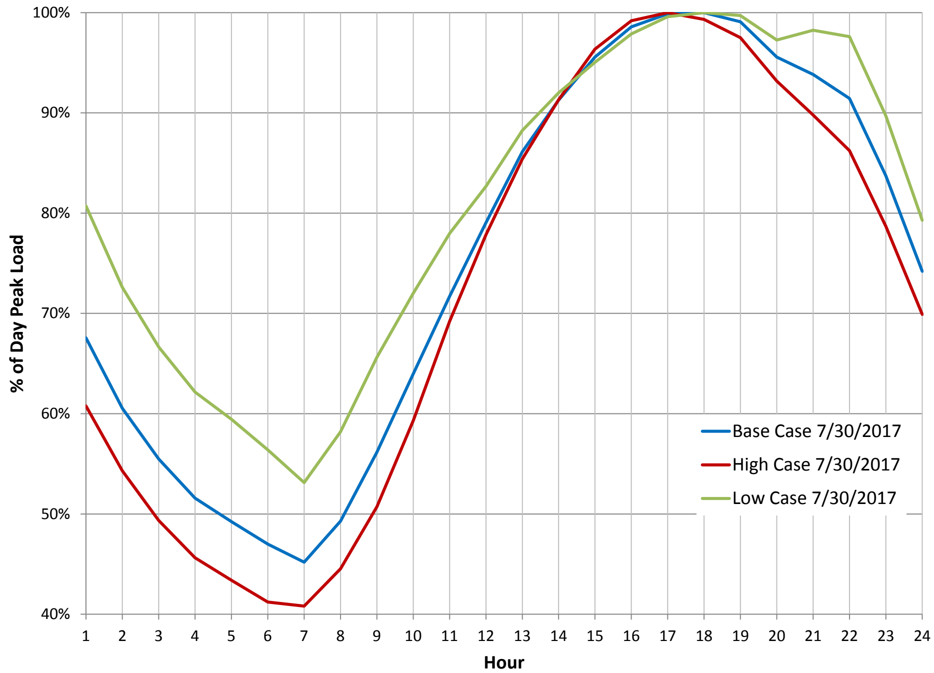
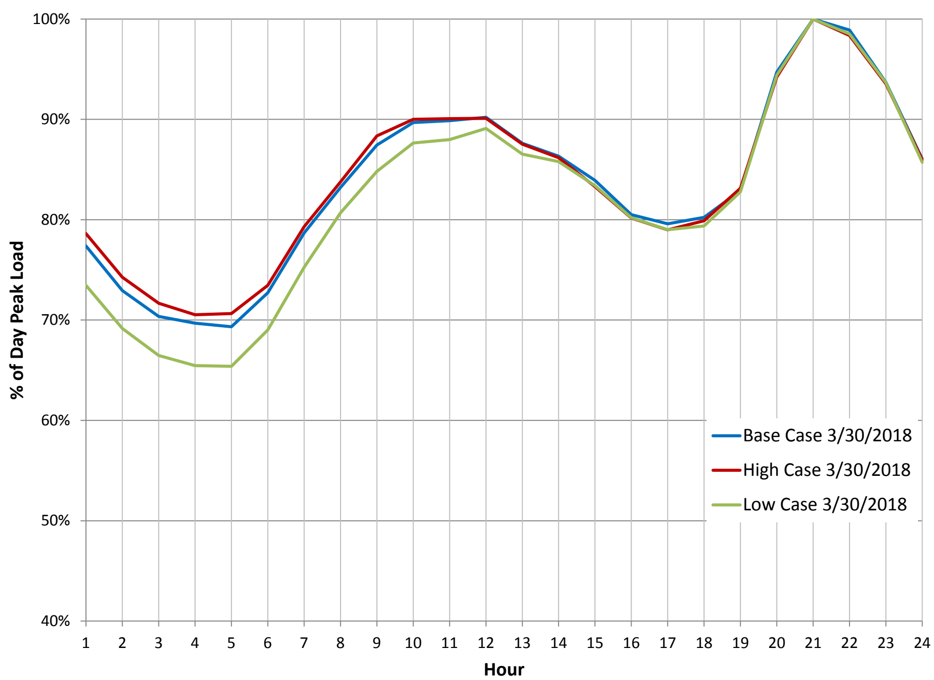
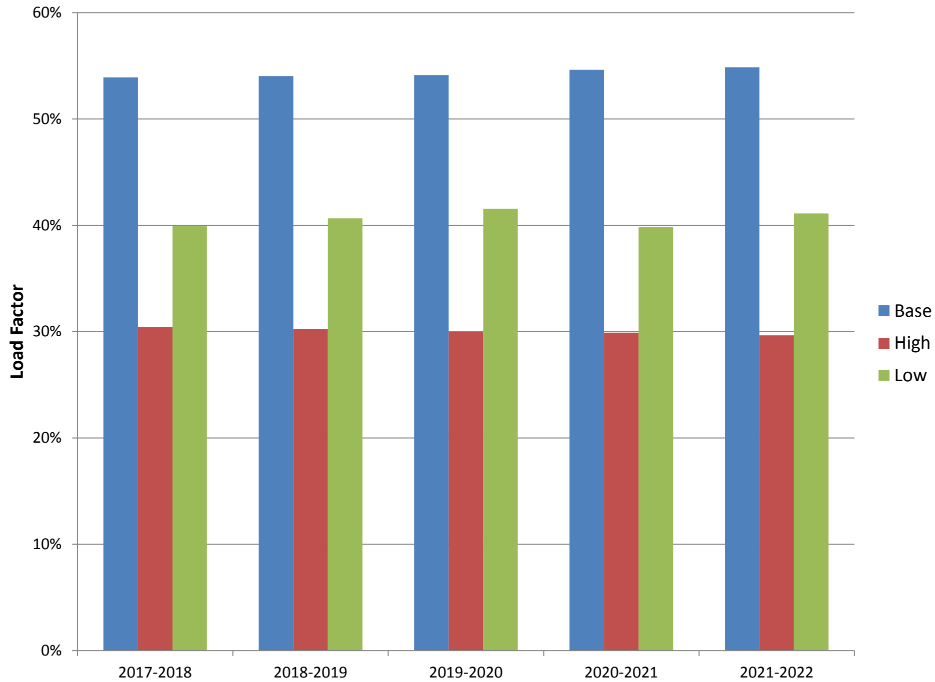


Figure 3-16: Sample Daily Load Shape, Spring Day in ComEd's Forecasts



The annual load factors are shown in Figure 3-17. 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 3-17: 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 Illinois Electric Customers and Sales Forecasts: 2017-2026.* 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.

- *MidAmerican Energy Company: Election to Procure Power and Energy for a Portion of its Eligible Illinois Retail Customers, Procurement Year – 2017.* This document provided energy efficiency disclosures required under Section 16-111.5B of the PUA and further information relating to MidAmerican's load forecasts and energy efficiency, and was sent along with MidAmerican's latest energy efficiency potential study and information related to energy efficiency programs currently operating in the MidAmerican service territory.

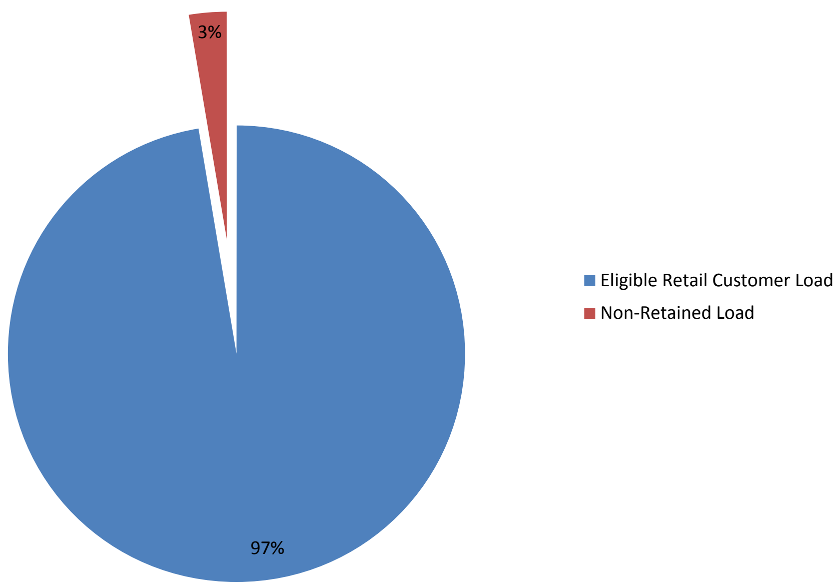
- Spreadsheets of load profiles, hourly load strips, procurement blocks, and scenario models for the base, high and low forecasts. (Summarized in Appendix G)

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 3-18 shows the forecasted annual percentage of usage by eligible retail customer load and non-retained retail customer load. 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 ARES).

Figure 3-18: MidAmerican's Forecast Retail Customer Load Breakdown, Delivery Year 2017-2018



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 3-19, incorporates the rate of customer switching in the past, and expected increases in the ARES service. The retail choice switching forecast was derived by reviewing recent switching activity and projecting forward recent trends. The figure breaks down the total forecast of the total customer load, in the same way as Figure 3-18 does for a single year.

Figure 3-19: MidAmerican's Forecast Retail Customer Load by Delivery Year

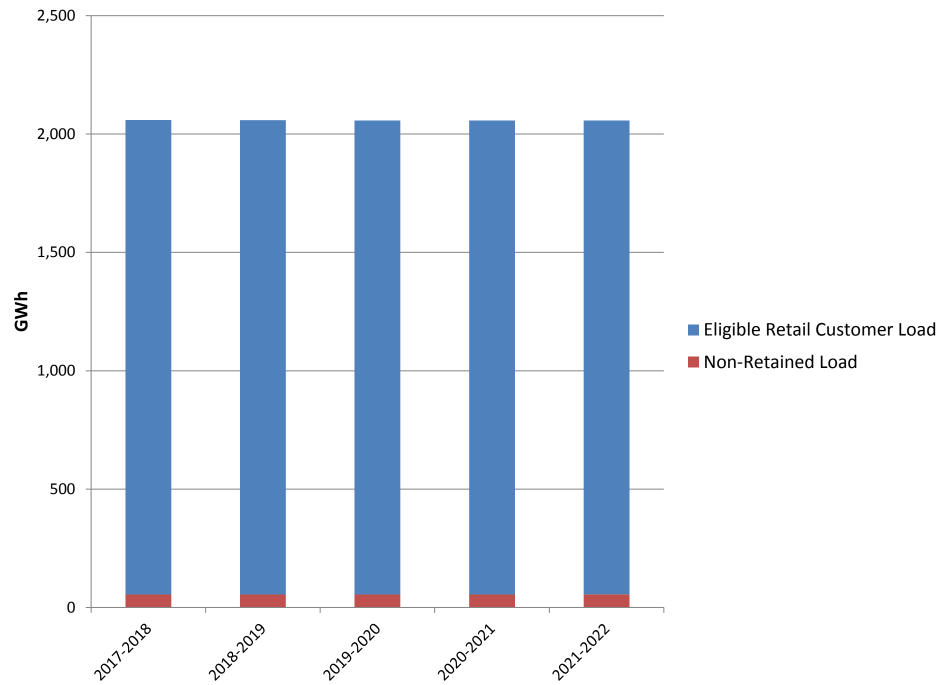
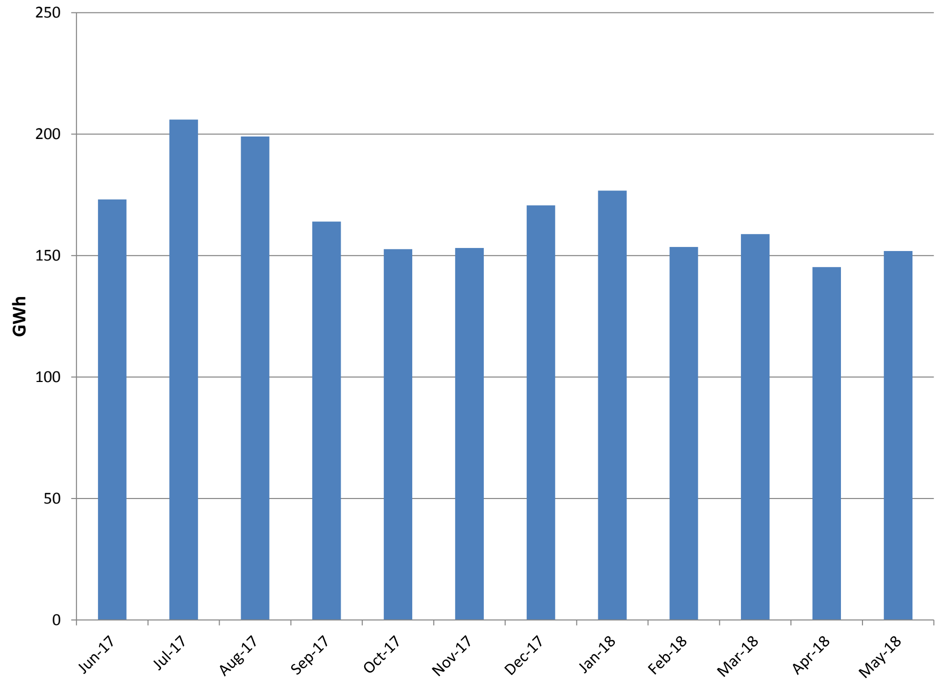


Figure 3-20 provides a monthly breakdown of the base case forecast of MidAmerican retained eligible retail customer load, that is, the load of customers on bundled supply to be considered under this Procurement Plan.

Figure 3-20: MidAmerican's Forecast 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 and the 95% confidence interval around the non-coincident gross peak demand forecast. The load forecasting software used for the sales, customers 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 reference case load forecast is based on the model utilizing economic and demographic data that were obtained from an external source database. 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.

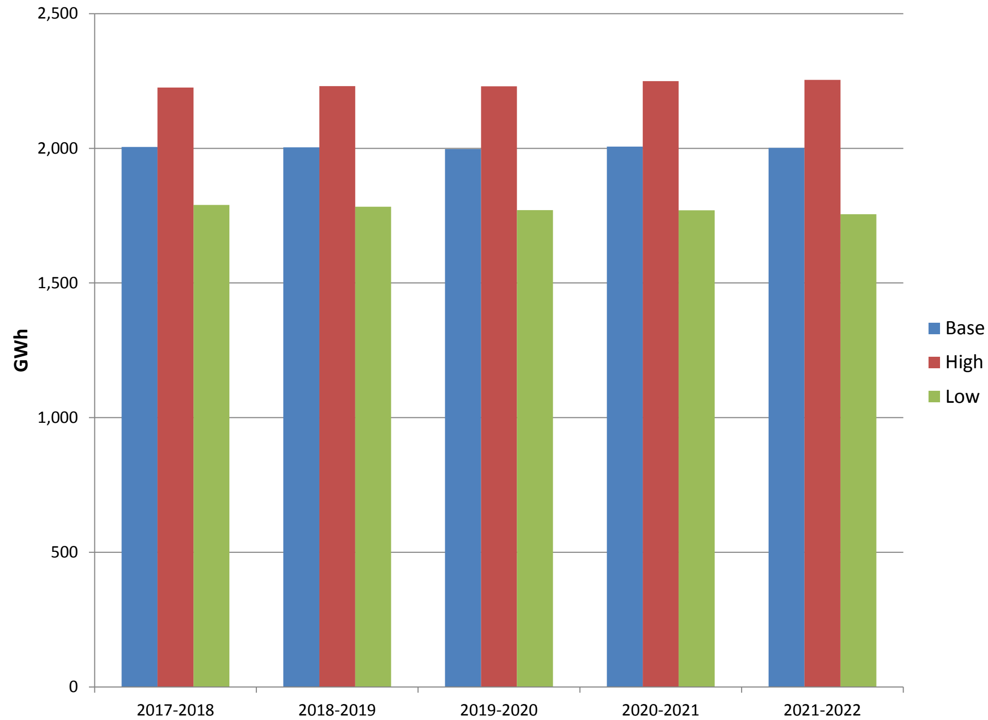
3.4.2 Weather

The reference case temperature assumptions in the hourly load forecast model were not changed for the scenarios. The reference 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 reference case forecasts for retail switching sales, customers, and demand in MidAmerican Illinois service territory were not changed in the scenarios. Figure 3-21 shows the forecasted MidAmerican Illinois supply obligation in each case.

Figure 3-21: Supply Obligation in MidAmerican's Forecasts



3.4.4 Load Shape and Load Factor

Figure 3-22 and Figure 3-23 display the hourly profile of the utility supply obligation in each case (relative to the daily maximum load). Figure 3-22 illustrates a summer day, and Figure 3-23 shows a spring day. There is no meaningful difference between the base, low and high load shapes on a sample summer day, or on a sample spring day.

Figure 3-22: Sample Daily Load Shape, Summer Day in MidAmerican's Forecasts

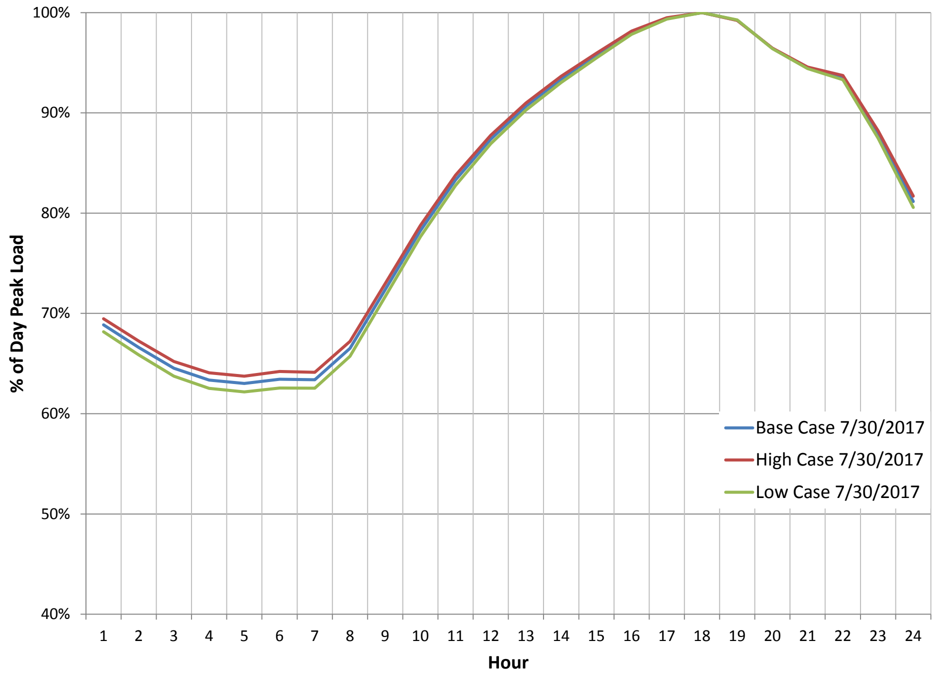
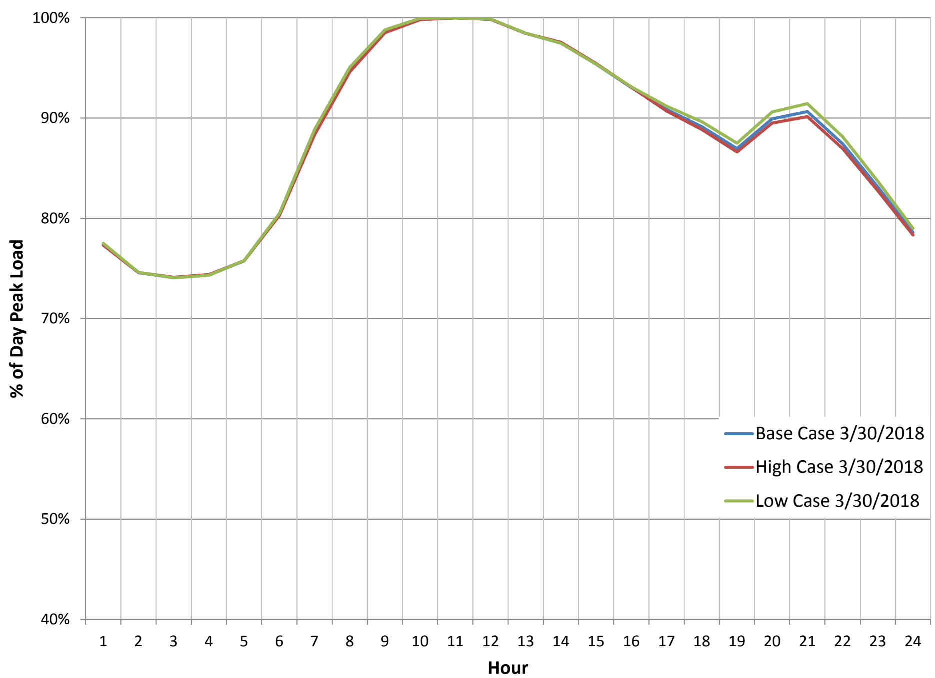
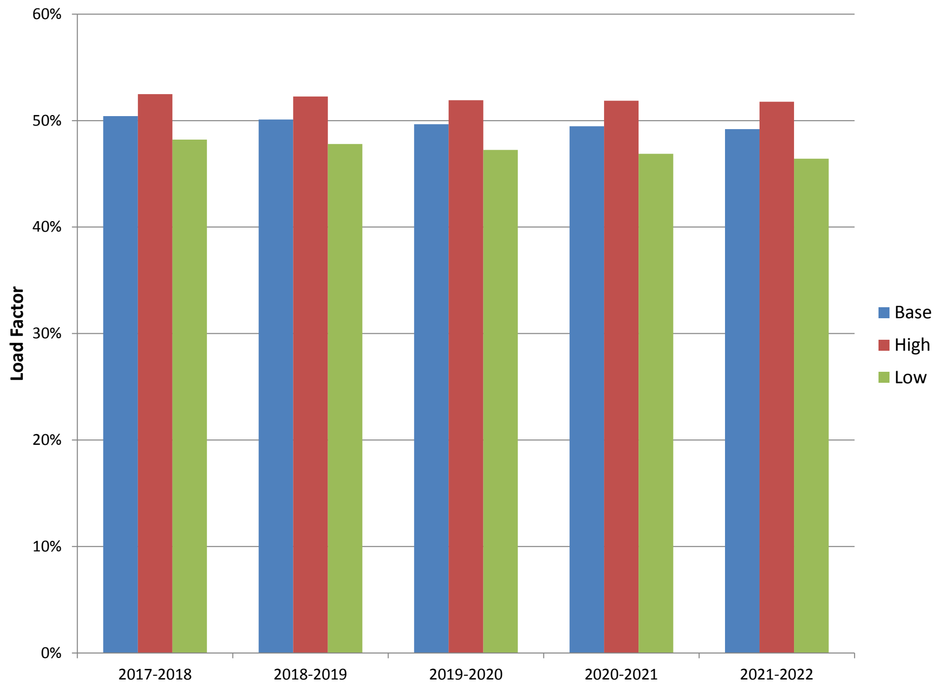


Figure 3-23: Sample Daily Load Shape, Spring Day in MidAmerican's Forecasts



The annual load factors are shown in Figure 3-24. As expected, the base, the high and the low case load factors are consistent being within the 46-52% range.

Figure 3-24: 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. So 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 groups 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 ±9% 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 represent 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 forecast, 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

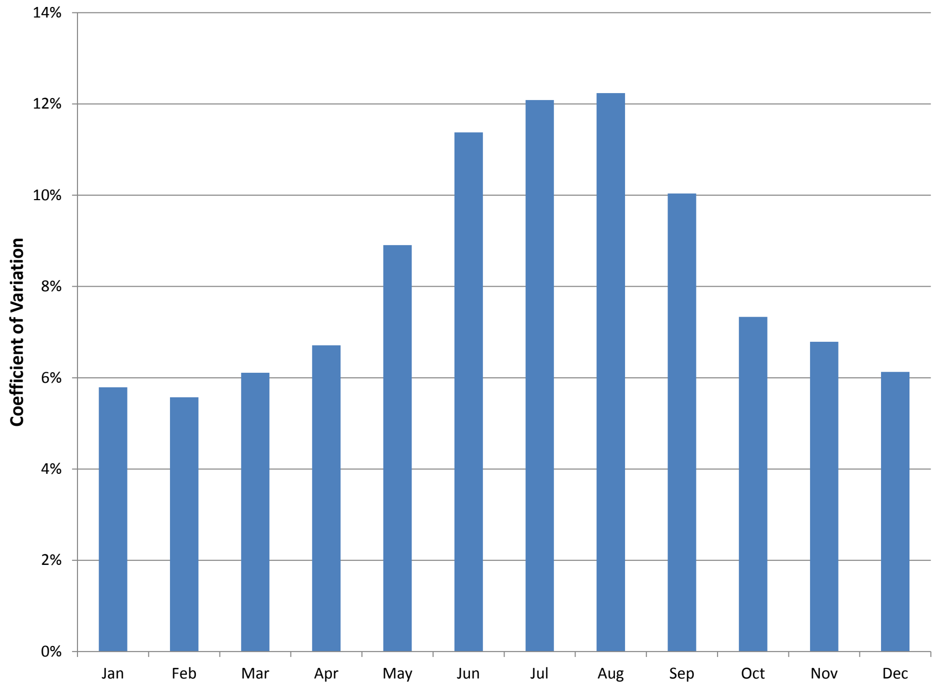
On a short-term basis, weather fluctuations are a key driver of the uncertainty in load forecasts, and in the daily variation of load forecasts around an average-day forecast. The discussion of high and low scenarios in Sections 3.2.2, 3.3.2, and 3.4.2 notes the way that Ameren Illinois, ComEd, and MidAmerican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

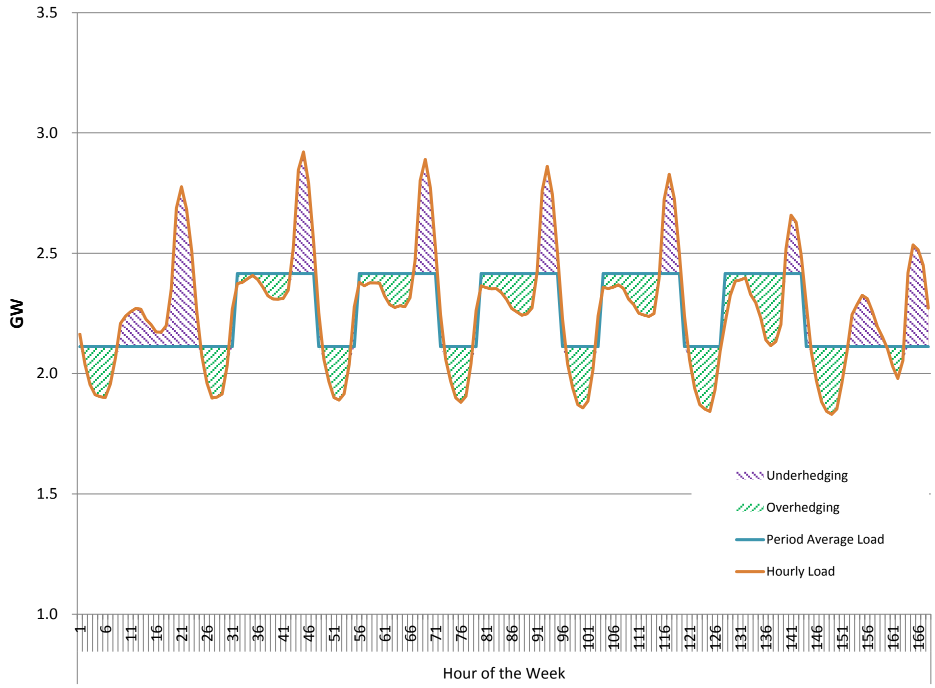
Figure 3-25 illustrates this disconnect by showing, for each month, the average historical "daily coefficient of variation" for peak period loads. This figure is based on historical ComEd loads from 2009 through 2015, normalized to the monthly base case forecasts in the first delivery year. To calculate 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 3-25: 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 3-26, below.

Figure 3-26: 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 62% of potentially-eligible retail customer load[110] will have switched away from Ameren Illinois fixed price tariff by the end of the 2017-2018 delivery year. This level represents an increase in the switching statistics from the 58% assumed in the July 2015 forecasts and is informed by higher than forecasted actual switching through April 2016 driven in part by communities deciding to renew their municipal aggregation programs with alternative suppliers. Savings opportunities that existed prior to 2014 drove the growth in residential switching, and the trend has continued in 2016. A temporary decline in switching to ARES in 2015 may be attributed to the effect of the polar vortex and various municipal aggregation communities suspending their programs. ComEd projects 43% switching to ARES by potentially eligible retail customers by the end of the 2017-2018 delivery year, which represents a decline from the 46.2% switching rate assumed in the July 2015 forecasts. At this point, the uncertainty around municipal aggregation and switching may be more related to the chance that utility load will increase due to customers return to default service. To a lesser extent the same is true with regards to the uncertainty around the extent to which, as aggregation levels decline, individual retail switching may or may not increase. But this is uncertain and it is possible that customer migration away from utility supply could resume within the planning horizon. Both Ameren Illinois and ComEd have assumed a wide range of switching fractions in the low and high scenarios (return to utility service would be represented as a decrease in the switching fraction over time).

In addition to offers to customers made through municipal aggregation programs, ARES offer a variety of products directly to customers – some of which have a similar structure to the utility bundled service, while others vary significantly in structure. These include offers with pass-through capacity prices, "green" energy above the mandated RPS level, month-to-month variable pricing, longer-term fixed prices, options to match prices in the future, options to extended contract terms, and options to adjust prices retroactively.[111]

[110] "Potentially-eligible retail customer load" refers to the load of those customers eligible to take bundled service from the utility.
[111] For more information on choices offered by ARES, see the 2016 Annual Report of the ICC Office of Retail Market Development at http://www.icc.illinois.gov/downloads/public/2016%20ORMD%20Section%2020-110%20report.pdf.

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, 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 that currently exists between the utility price to compare[112] and representative ARES prices[113] available to eligible utility customers. It appears that, currently, ARES fixed price offers for a similar term to the utility price do not offer savings or benefits to individual residential customers. 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[114] and Utility Price to Compare

Utility Territory	Utility Price to Compare (¢/kWh)	Representative ARES Price (¢/kWh)
Ameren Illinois (Zone I)	6.51	6.69
Ameren Illinois (Zone II)	6.51	6.73
Ameren Illinois (Zone III)	6.51	6.71
ComEd	6.39	7.12

3.5.5 Hourly Billed Customers

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

3.5.6 Energy Efficiency

Public Act 95-0481 also created a requirement for ComEd and Ameren Illinois to offer cost-effective energy efficiency and demand response measures to all customers.[115] Both Ameren Illinois and ComEd have incorporated the impacts of these statutory and spending-capped efficiency goals, as applied to eligible retail customers, as well as achieved and projected savings in the forecasts that are included with this Procurement Plan. Chapter 9 of this plan discusses the proposed incremental energy efficiency programs that have been submitted pursuant to Section 16-111.5B. These programs are reflected in the load forecasts. Pursuant to a separate provision in the Public Utilities Act,[116] MidAmerican also has energy efficiency programs operating in its Illinois service territory. MidAmerican expects that the projected energy efficiency program impact would be consistent with the historical levels; therefore, no adjustment was made to the forecasting models.

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[112] July 2016 utility cost to compare from http://www.pluginillinois.org/MunicipalAggregation.aspx.
[113] Representative ARES prices are an average of 12-month fixed price offers from ARES available at http://www.pluginillinois.org/OffersBegin.aspx as of September 27, 2016.
[114] Offers without an explicit premium renewable component.
[115] See P.A. 95-0481 (Section originally codified as 220 ILCS 5/12-103).
[116] See 220 ILCS 5/8-408.

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 they are 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

The Agency's 2016 *Annual Report: The Costs and Benefits of Renewable Resource Procurement* included an update on the development of the energy storage technology.[117] As of the first quarter of 2016, the U.S. DOE listed 201 operational battery-based storage systems with a total capacity of 405 MW operating in the U.S. Illinois was listed as having 12 projects with 73 MW in operation, placing it among the leaders in states with battery storage projects currently in operation. However, it is too early to forecast the impact on load forecasts, and the Agency notes that there are not clear provisions in Illinois law to encourage the adoption of these technologies. The Agency will continue monitor the development of the energy storage market in the coming years.

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. Ameren Illinois and ComEd forecasts include already approved energy efficiency programs, and MidAmerican's forecast includes verified energy efficiency program impacts as well. The IPA also recommends that the Commission approve the additional incremental energy efficiency programs and measures as presented in Chapter 9. The March 2017 load forecasts should also reflect those newly approved programs.

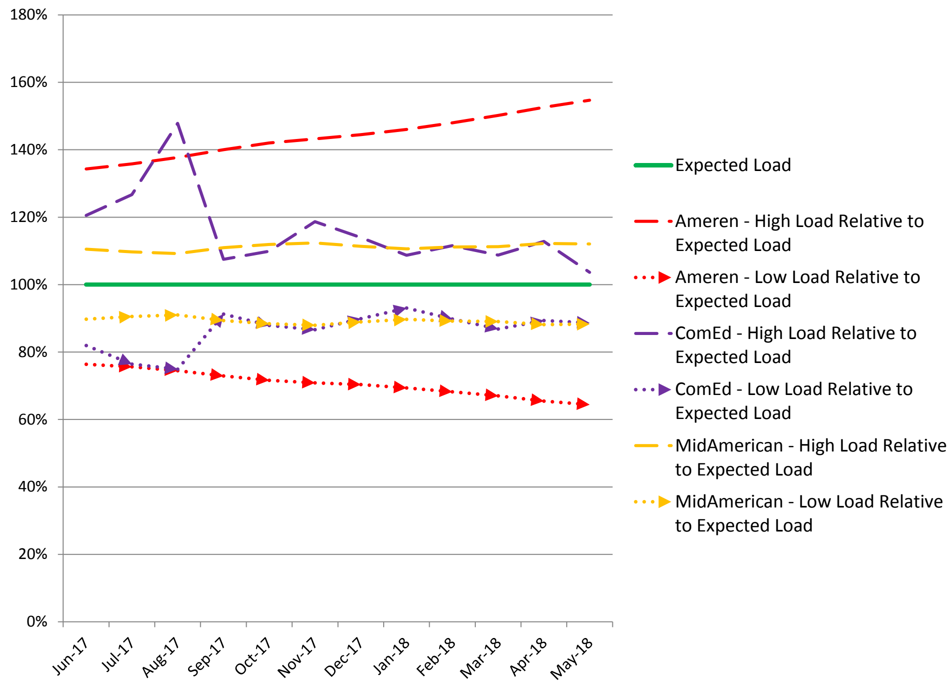
3.6.2 High and Low Excursion Cases

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 3-27, the Ameren Illinois low and high load forecasts are on average equal to 71% and 144% of the base case forecast, respectively, during the 2017-2018 delivery year. Comparatively, for the same period, ComEd's low and high load forecasts are on average equal to 86% and 116% 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 89% and 111%, respectively. Switching assumptions play no explicit role in the MidAmerican high and low load forecasts. Instead, the MidAmerican high and low load forecasts are a product of a mathematical construct.

[117] That report can be found here: http://www.illinois.gov/sites/ipa/Documents/IPA-2016-Renewables-Report.pdf.

Figure 3-27: Comparison of Ameren Illinois, ComEd, and MidAmerican High and Low Forecasts for Delivery Year 2017-2018



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 3-26, 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 purchased energy supply in standard 25MW on-peak, and off-peak blocks. The energy block size was reduced from 50 MW to match supply with load more accurately.[118] 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.[119] The 2016 Procurement Plan included procurement of energy supply to meet the needs of MidAmerican's eligible retail customers as well as those of ComEd and Ameren Illinois. The current plan will continue the procurement of energy supply 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. 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 current IPA procurement strategy involves procurement of hedges to meet a portion of the hedging requirements over a three year period and includes two procurement events in which the July and August peak requirements will be hedged at 106%, while the remaining peak and off-peak requirements will be hedged at 100%. In the spring procurement event, 106% of the July and August expected peak, 100% of the July and August off-peak, 100% of the June and September peak and off-peak, and 75% of the October through May peak and off-peak requirements for the 2017-2018 delivery year will be targeted for procurement. The fall procurement event will bring the targeted hedge levels to 100% for October through May of the 2017-2018 delivery year. A portion of the targeted hedge levels for the 2018-2019 and the 2019-2020 delivery years of 50% and 25%, respectively, will be acquired spread on an equal basis in the spring and fall procurement events.

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:

- A 20-year bundled REC and energy purchase (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.
- The February 2012 "Rate Stability" procurements mandated by Public Act 97-0616 for block energy products covering the period June 2013 through December 2017.[120]

Under the current utility load forecasts, which contemplate relatively flat customer switching, curtailment of the Ameren Illinois and ComEd LTPPAs is unlikely for the 2017-2018 delivery year. MidAmerican is not covered by either LTPPAs or Rate Stability procurements.

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.[121]

[118] See 2014 IPA Procurement Plan at 93.
[119] http://www2.illinois.gov/ipa/Pages/Prior_Approved_Plans.aspx.
[120] P.A. 97-0616 also mandated associated REC procurements, but these REC procurements do not impact the (energy) resource portfolio.
[121] Docket No. 12-0544, Final Order dated December 19, 2012 at 228-237; see also Docket No. 13-0034, Final Order dated June 26, 2013 ("Phase II" approving sourcing agreement as required in Docket No. 12-0544).

However, DOE funding support for FutureGen 2.0 has been suspended, terminating development of the project.

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.

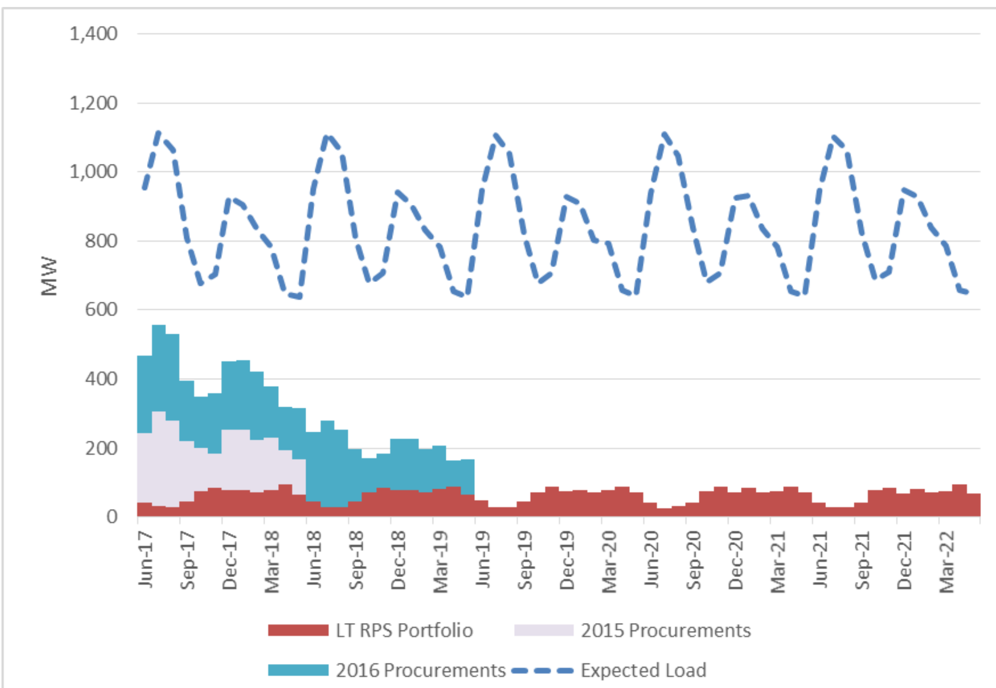
4.1 Ameren Illinois Resource Portfolio

Figure 4-1 shows the current supply gap in the Ameren Illinois supply portfolio for the five-year, June 2017 through May 2022, planning period, using the base case on-peak forecast described in Chapter 3.

Ameren Illinois' existing supply portfolio, including long-term renewable resource contracts, is not sufficient to cover the projected load for the 2017-2018 delivery year. Additional energy supply will be required for the entire 5-year planning period. Approximately 62% of the Ameren Illinois residential 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.

Figure 4-1: Ameren Illinois' On-Peak Supply Gap - June 2017-May 2022 Period - Base Case Load Forecast



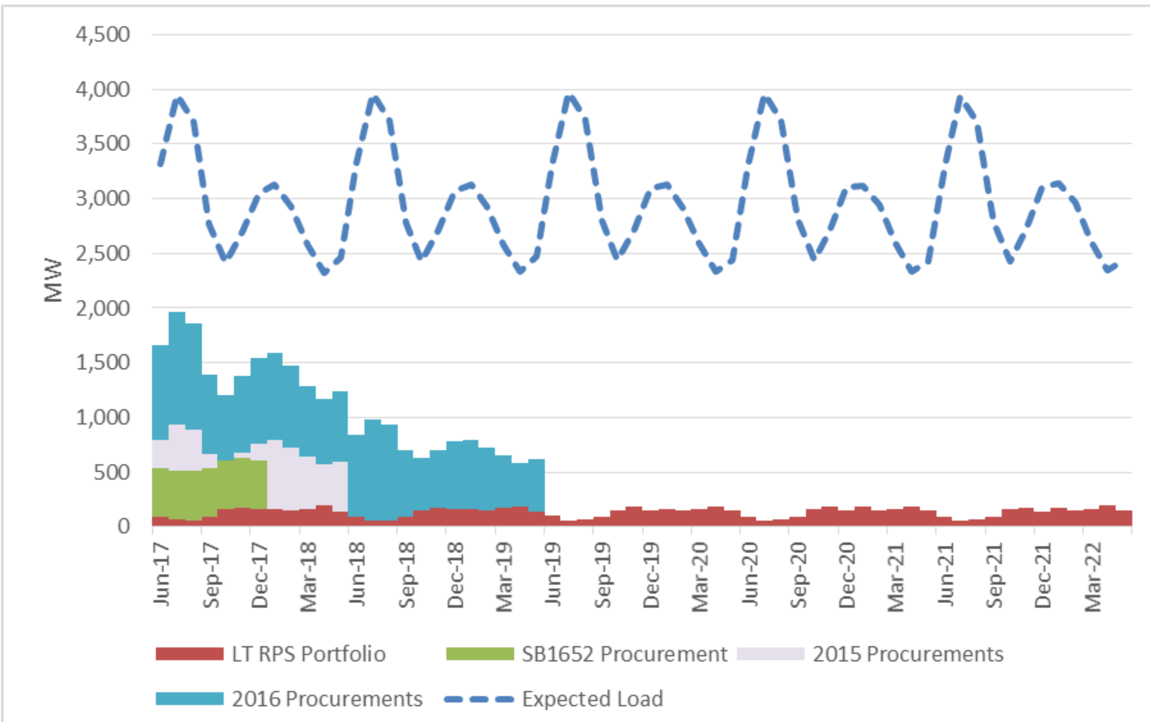
Under the base case load forecast scenario, the average supply gap for peak hours of the 2017-2018 delivery year is estimated to be 421 MW, the peak period average supply gap for the 2018-2019 delivery year is estimated to be 629 MW, and the average peak period supply gap for the 2019-2020 delivery year is estimated to be 772 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 2017-May 2022 planning period, using the base case load on-peak forecast described in Chapter 3.

ComEd's current energy resources will not cover eligible retail customer load starting in June 2017. The average supply gap during peak hours for the 2017-2018 delivery year under the base case load forecast is estimated to be 1,505 MW. The average supply gap during peak hours for the 2018-2019 and 2019-2020 delivery years is estimated to be 2,251 MW and 2,856 MW respectively.

Figure 4-2: ComEd's On-Peak Supply Gap - June 2017-May 2022 period - Base Case Load Forecast



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. MidAmerican's existing eligible retail customer load is served by an allocation of capacity from MidAmerican's resources ("Illinois Historical Resources").

In reviewing the load forecast and resource portfolio information supplied by MidAmerican for the 2017 Plan, the IPA notes that MidAmerican "dispatches" its Illinois Historical Resources whenever the expected cost to generate electricity is less than the expected cost of acquiring it in the market. The maximum generation output during each hour is then capped at the maximum of the generation capacity or the forecasted demand level, whichever is lower. The IPA recommends removing this cap for the 2017 Procurement Plan. Removing the cap represents an incremental improvement and would entail no effort to implement.[122]

In determining the amounts 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 2016 Procurement Plan approved by the Commission.

The IPA recognizes that in MidAmerican's case the amount of energy production available varies hour-to-hour, and it does not behave exactly the same as fixed energy blocks. For example, the amount of energy to be delivered under fixed energy blocks remains constant during the contract delivery period while MidAmerican's generation does not. According to the MidAmerican methodology submitted as part of the July forecast, the energy production by its Illinois Historical Generation fleet depends on the forecast energy prices: the lower the forecast price, the lower the generation dispatch. Thus, the forecast supply gap for MidAmerican has uncertainty on both inputs to the estimate (load and supply uncertainty). However, one important aspect of MidAmerican's risk position is the positive correlation between the two major inputs, i.e., the hourly load and the hourly dispatch of the generation fleet. This positive correlation reduces the uncertainty of the differential to some degree because deviations in the load forecast will be largely negated (or offset) by the corresponding deviation in the generation dispatch.

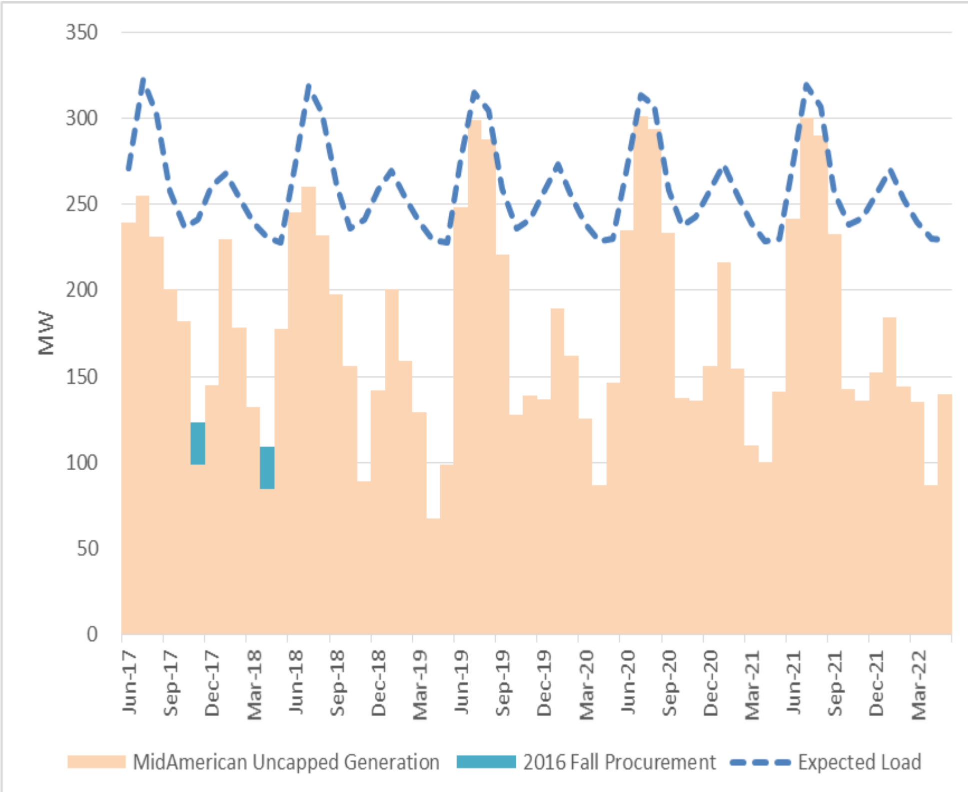
The IPA believes that the methodology used with regards to MidAmerican's supply procurement is reasonable given this correlation and that the overall hedging levels and laddered procurement approach are consistent with the proposed approach for Ameren Illinois and ComEd. The IPA understands that the basic methodology adopted in the 2016 Procurement Plan and continued in this Plan has produced hedge volumes that successfully matched the supply/load balance for June and July, 2016. The IPA and MidAmerican will monitor the actual performance of this approach and will revisit it in future procurement plans, if warranted.

Due to current and anticipated MidAmerican generating unit retirements, MidAmerican will rely to a greater extent on the IPA procurements to make up the difference between generation allocated to serve its Illinois eligible retail customer load. MidAmerican's current forecasts include an allocation of approximately 49 MW from MidAmerican's 25 percent ownership in the Quad Cities nuclear generating Units 1 and 2 through the 5-year forecast period ending May 31, 2022. The Quad Cities units could be retired before the end of the current forecast period and potentially before the end of the current plan's 3-year procurement horizon. MidAmerican would modify its generation forecast to incorporate the impact of these retirements on the projected supply gaps to be covered by the IPA procurements.

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 gap during peak hours for the 2017-2018 delivery year under the base case load forecast is estimated to be 80 MW. The average supply gap during peak hours for the 2018-2019 delivery year is 95 MW and for the 2019-2020 delivery year the supply gap is 79 MW.

[122] Tables G-5 and G-6 in Appendix G show monthly capped and uncapped generation dispatch and residual values for peak and off-peak periods

Figure 4-3: MidAmerican's On-Peak Supply Gap - June 2017-May 2022 period - Base Case Load Forecast



5 MISO and PJM Resource Adequacy Outlook and Uncertainty

As a result of retail choice in Illinois, the resource adequacy challenge (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 Section 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 over the planning horizon, this Section 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 to establish and enforce reliability standards with the goal of ensuring the reliability of the American bulk power system.
- Midcontinent ISO ("MISO"), which operates the transmission grid in most of central and southern Illinois, serving Ameren Illinois and MidAmerican.
- PJM Interconnection ("PJM"), which operates the transmission grid in Northern Illinois, serving ComEd.

From review 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 those regions. MISO, on the other hand, could be short resources starting in the 2021-2022 timeframe.

5.1 Resource Adequacy Projections

In PJM, capacity is largely procured through PJM's capacity market, the Reliability Pricing Model ("RPM"), which was approved by FERC in December 2006. In 2015 PJM implemented changes to the RPM construct, which established a Capacity Performance product.[123] 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.[124] The commitment period is also referred to as a Planning Year.[125] In addition to the BRAs, up to three incremental auctions are held, at intervals 20, 10, and 3 months prior to the Planning 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 for such Planning Year.

Just prior to the beginning of each Planning Year, the Final Zonal Net Load Price, which is the price paid by Load Serving Entities ("LSEs") for capacity procured as part of RPM in PJM, is calculated. This price is

123 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 ("the Capacity Performance Filing"). 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 implemented for the 2018-2019 and 2019-2010 planning years, with transitional capacity performance incremental auctions conducted for the 2016-2017 and 2017-2018 planning years to facilitate improved resource performance during those years by allowing a portion of capacity to be rebid in a new procurement. Implementation of Capacity Performance has generally resulted in increased capacity clearing prices, in particular for the ComEd zone.

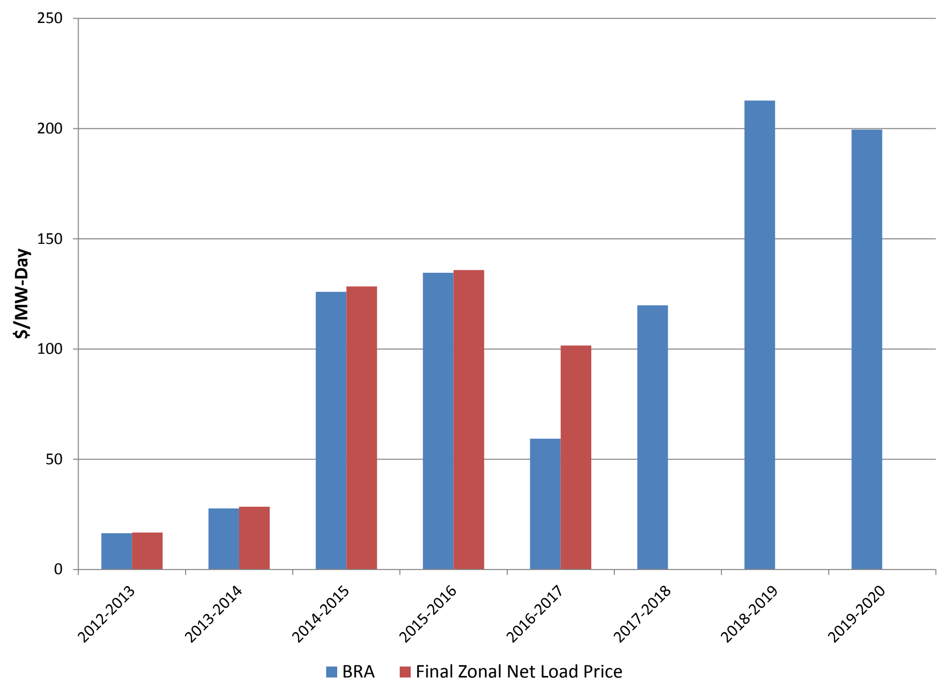
124 Note that the BRA for the 2018-2019 Planning Year was delayed from May, 2015 to August, 2015.

125 A Planning Year is June 1 through May 31 of the following year. Planning Year is used in this Plan in relation to capacity procurement.

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

determined based on the results of the BRA and subsequent incremental auctions for a given Planning 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 and the Final Zonal Net Load Price as shown in Figure 5-1. However, while Figure 5.1 shows little variation between the BRA clearing price and the Final Zonal Net Load Price for the Planning Years through 2015-2016, Planning Year 2016-2017 shows a significant variation between the prices. This is because the Final Zonal Net Load Price for 2016-2017 includes the incremental costs of that year's transitional Capacity Performance Incremental Auction ("CPIA").[127] A similar variation in the prices is expected for the 2017-2018 Planning Year after the costs for that Planning Year's CPIA are taken into account.[128] Figure 5.1 also shows increases in the preliminary BRA prices for Planning Years 2018-2019 and 2019-2020, which can also be primarily attributed to the implementation of the capacity performance product.[129]

Figure 5-1: PJM RPM (ComEd Zone) Capacity Price for Planning Years 2012-2013 to 2019-2020[130]



As shown in Figure 5-2Figure 5-2, PJM is projected to have sufficient resources to meet load plus required reserve margins for the Delivery Years 2016-2017 to 2021-2022, with projected reserve margins above the 15.5% target reserve margin in 2016-2017 and the 15.7% target reserve margin for the remaining Delivery Years. For the 2016-2017 Delivery Year, the reserve margin is approximately 10% above the target reserve margin, peaks at approximately 16% above the target reserve margin in 2018-2019 and then drops to approximately 12% above the target reserve margin for the 2021-2022 Planning Year.

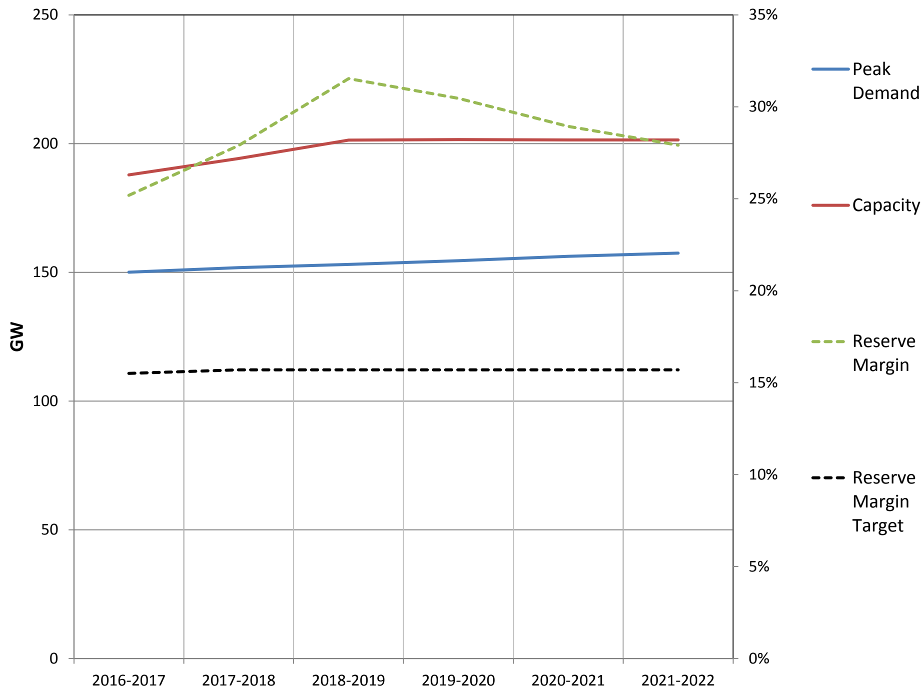
[127] The BRA clearing price for the ComEd zone for 2016-2017 was $59.37/MW-Day. 60% of resources procured in the 2016-2017 CPIA were Capacity Performance Resources. The preliminary incremental cost component for the 2016-2017 CPIA was $38.17/MW-Day and the final incremental cost component was $39.86/MW-Day. 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.

[128] 70% of resources procured in the 2017-2018 CPIA were Capacity Performance Resources.

[129] In 2018-2019 and 2019-2020 the ComEd Zone was modeled as a separate Locational Deliverability Area ("LDA"), and in both years the results showed that it was a constrained LDA. Binding constraints therefore also contributed to the higher clearing price. In 2018-2019 and 2019-2020, 80% of resources procured were Capacity Performance Resources.

[130] 2016-2017 is the latest Planning Year for which the Final Zonal Net Load Price has been calculated. It will be calculated for future Planning Years as the start of the year approaches.

Figure 5-2: PJM NERC Projected Capacity Supply and Demand for Planning Years 2016-2017 to 2021-2022



Source: NERC 2015 Long Term Reliability Assessment ("NERC 2015 LTRA")

The MISO Resource Adequacy Construct, specified in Module E-1 of its Tariff,[131] 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")[132] for the Planning Year. An LSE's total resource adequacy obligation is referred to as the Planning Reserve Margin Requirement ("PRMR"). On June 11, 2012 the Federal Energy Regulatory Commission ("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 ("PRA"). MISO implemented the Module E-1 RAR, which became fully effective on June 1, 2013. More details on the locational construct of the MISO RAR and MISO's fourth PRA are provided in Section 5.2.

As shown in Figure 5-3, based upon the NERC 2015 LTRA, on a region-wide basis MISO is expected to have sufficient resources to meet load plus required reserve margin for the Planning Years 2016-2017 to 2020-2021 with projected reserve margins above the 14.3% target reserve margin. However, in 2021-2022 MISO is projected to have insufficient resources to meet load plus required reserve margin. For the 2016-2017 Planning Year, the reserve margin is approximately 2% above the target reserve margin, dropping to approximately 0.4% above the target reserve margin for the 2020-2021 Planning Year. As also shown in Figure 5-3, NERC's analysis mirrors MISO's analysis presented in the 2015 MISO Transmission Expansion Planning ("MTEP") report, which addresses resource adequacy. The MISO assessment, however, forecasts the reserve margin dropping below the target reserve margin a year earlier in 2020-2021. MISO explains that the difference is primarily due to how each assessment accounts for certain types of resources as well as how the reserve margin is calculated. In particular, MISO notes that the MTEP report does not include "low-certainty"

[131] 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.
[132] 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 their jurisdiction, then that state-set PRM would be adopted by MISO for jurisdictional LSEs in such state.

resources; whereas the NERC assessment includes these resources in the overall supply pool.[133] In 2020-2021 there are 2.3 GW of "low-certainty" resources which MISO did not include in its base case. If MISO had included these resources in 2020-2021, the MISO assessment would have been above the target reserve margin, similar to the NERC assessment. MISO also explains that the MISO and NERC assessments differ in how the reserve margin percent is calculated. MISO's calculation of the reserve margin counts DR as a resource while the NERC assessment has DR calculated on the demand side. MISO however notes that while the reserve margin percent will be slightly different, the absolute GW shortfall/surplus is the same between the two assessments.

Both NERC and MISO draw the same conclusions from the long-term resource assessments which can be summarized as follows:

- All zones within MISO are sufficient from a resource adequacy point of view in the near term, when available capacity and transfer limitations are considered. Regional shortages in later years may be rectified by the utilities and, as such, do not cause immediate concern.
- The change in LTRA results was driven primarily by the combination of an increase in resources committed to serving MISO load and a decrease in load forecasts.
- The increase in committed resources reflects action taken by MISO LSEs and state regulators to address potential capacity shortfalls.
- MISO projects that each zone within the MISO footprint will have sufficient resources within their boundaries to meet the local clearing requirements, or the amount of their local resource requirement, which must be contained within their boundaries.
- Several zones are short against their total zonal requirement, when only resources within their boundaries or contracted to serve their load are considered. However, those zones have sufficient import capability, and MISO has sufficient surplus capacity in other zones to support this transfer. Surplus generating capacity for zonal transfers within MISO could become scarce in later years if no action is taken in the interim by MISO LSEs.
- MISO limited the transfer of capacity from the South region to the North/Central region to 1,000 MW.[134] Any capacity in the south above its requirements and 1,000 MW was therefore excluded from the MISO-wide capacity reserves in the assessment, since this capacity was assumed unavailable for the North/Central region's capacity needs.

MISO projects that reserve margins will continue to tighten over the next five years, approaching the target reserve margin. Operating at the reserve margin creates a new operating reality for MISO members where the use of all resources on the system and emergency operating procedures are more likely. This could lead to a projected dependency in the use of load-modifying resources such as behind-the-meter generation and DR.

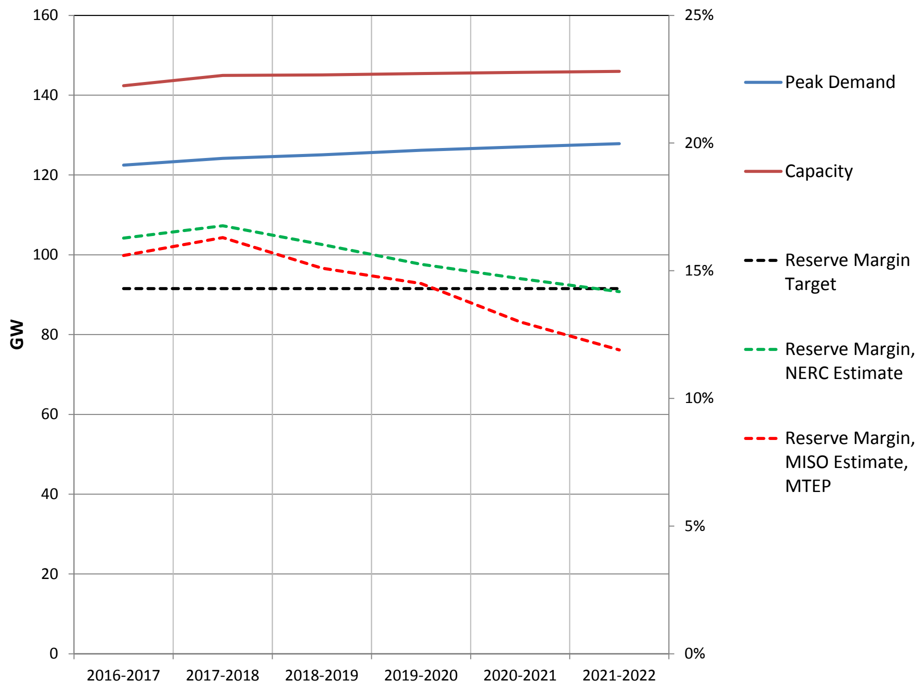
The LTRA results represent a point-in-time forecast, and the NERC assessment notes that MISO expects these figures to change significantly as future capacity plans are solidified by LSEs and states. In the MTEP MISO also notes that 91% of the load in the MISO footprint is served by utilities with an obligation to serve. This obligation is reflected as a part of state and locally jurisdictional integrated resource plans that only become certain upon the receipt of a Certificate of Public Convenience and Need ("CPCN"). MISO further notes that five years is sufficient lead time for LSEs to plan, build and operate new resources to meet the projected

[133] "Low-Certainty" resources are those resources that have some indication of not being available to serve load in a given Planning Year (*i.e.* the certainty of them being able to serve load is low). In other words, while "low-certainty" resources may be available to serve MISO load, they do not have any firm commitments to do so. Most "low-certainty" resources are potential retirements or suspensions.

[134] The 2016 Procurement Plan provided details on the 1,000 MW contract path limit and the dispute between MISO and SPP regarding flows above the contract path limit. On January 21, 2016 FERC approved a Settlement Agreement between MISO, SPP and other parties that resolved the disputed issues. It should be noted that, as explained in the 2016 Procurement Plan, the transmission system can support flows above this 1,000 MW contract path and these flows are allowed in the operational time frame.

shortfall. However, the IPA notes that because Illinois is a retail-choice state where LSEs do not own generation, this construct may not apply as clearly to Illinois.

Figure 5-3: MISO NERC Projected Capacity Supply and Demand for the Planning Years 2016-2017 to 2021-2022



Source: NERC 2015 Long Term Reliability Assessment, MISO 2015 MTEP Book 2 Resource Adequacy

5.2 MISO Resource Adequacy Update

A key component of the MISO Module E-1 RAR is the establishment of Local Resource Zones ("LRZs"). The MISO region currently has 10 LRZs. Local Reliability Requirements ("LRRs") are set for each LRZ to establish the minimum amount of Planning Resources needed to maintain MISO's LOLE within each LRZ, without consideration of Planning Resources outside of the LRZ that could be accessed through transmission ties. MISO also establishes a Local Clearing Requirement ("LCR") for each LRZ, which is the minimum amount of Planning Resources required to be sourced within the LRZ while fully utilizing the Capacity Import Limit ("CIL") for the LRZ. Capacity Export Limits ("CEL") are also established for each LRZ. A market participant can qualify a Planning Resource, and convert the Unforced Capacity of the Planning Resource into Zonal Resource Credits ("ZRCs"). ZRCs are MW units of Planning Resources that have been converted into a credit that can be used to meet PRMR directly through offers or self-schedules in the PRA, or commitments in a Fixed Resource Adequacy Plan ("FRAP"). Market participants can also buy and sell ZRCs through bilateral arrangements. MISO will impose a Capacity Deficiency Charge ("CDC")[135] on an LSE that has not demonstrated at the close of the PRA, that it has sufficient capacity resources to meet its PRMR. MISO held the fourth PRA in April 2016.

The RTO-based reliability assessments examined in the previous Section are important measures of resource reliability in Illinois because the Illinois electric grid operates within the control of these two RTOs. The IPA concludes that it does not need to include any extraordinary measures in the 2017 Procurement Plan to assure reliability over the planning horizon.

[135] The value of the CDC is currently set at 2.748*Cost of New Entry ("CONE").

MISO, in consultation with its stakeholders, has been developing proposed changes to the MISO Resource Adequacy Construct. Key aspects of these proposed changes include:

- MISO is proposing several changes to their Resource Adequacy Construct which could potentially result in a more stable capacity market.[136] These changes include (i) the introduction of seasonal considerations to ensure transparency of resource adequacy across all seasons and provide flexibility to market participants, and (ii) addressing the locational construct to reduce volatility in the key inputs to the PRA. Increased stability may, or may not, be at a higher price than the current construct.
- MISO is proposing a competitive retail solution to specifically address the resource adequacy needs of Illinois and Michigan, the states within MISO that have competitive retail choice.[137] To the extent the solution results in the addition of new resources or the avoidance of existing resource retirement and coupled with the pending addition of new transmission lines in the region, it seems logical that the reliability of electric service for consumers in Illinois would be enhanced. As proposed, the competitive retail solution also includes a bright line test where all demand in Zone 4 subject to competitive retail access will be required to participate in the competitive retail solution. Advocates of the competitive retail solution believe it will address the needs of Illinois and Michigan without harm to the other states within MISO. Opponents believe it will increase capacity prices and/or volatility and will do so with no assurance that reliability will be enhanced.

If implemented, the proposed changes to the MISO resource adequacy construct could, in time, eliminate the need to enter into bilateral transactions altogether. The IPA also notes the lack of bilateral hedging of capacity in PJM where the RPM construct serves as an effective capacity auction for LSE's serving load in the PJM region.

5.2.1 Future Capacity Procurement Strategy for Ameren Illinois

The IPA recognizes that the proposed changes to the MISO capacity construct have received considerable debate among stakeholders and given the wide range of opinion, and the IPA believes it is currently unclear whether the proposed changes will result in a more stable capacity market in the near term. It is possible, however, that the proposed changes, when implemented, will reduce capacity price volatility, and could help ensure the reliability of electric service. As a result, the IPA bilateral capacity procurement approach may not have any apparent advantage over the future PRA approach. In light of the uncertainty around the proposed changes to the MISO resource adequacy construct, the IPA recommends deferral of the decision regarding hedging capacity for Ameren Illinois for the 2019-2020 planning year until next year's Plan.

5.2.2 2015-2016 PRA Results Follow-Up

FERC has taken several actions on the complaints filed regarding the results of the MISO 2015-2016 PRA. The complaints were filed by the Illinois Attorney General ("IL AG"),[138,] Public Citizen, Inc. ("Public Citizen"),[139] Southwestern Electric Cooperative ("SWEC"),[140] and the Illinois Industrial Energy Consumers ("IIEC").[141] A summary of the complaints was provided in the 2016 Procurement Plan.[142] The actions can be summarized as follows:

- Shortly after the conclusion of the 2015-2016 PRA, FERC's Office of Enforcement began a non-public, informal investigation under Part 1b of FERC's regulations into whether market manipulation or other potential violations of FERC orders, rules and regulations, occurred before or during the 2015-2016 PRA.

[136] See Section 5.2.5 for a more detailed discussion of the changes.
[137] See Section 5.2.6 for a more detailed discussion of the changes.
[138] FERC Docket EL15-71-000.
[139] FERC Docket EL15-70-000.
[140] FERC Docket EL15-72-000.
[141] FERC Docket EL15-82-000.
[142] See Pages 60-61.

On October 1, 2015, pursuant to the Federal Power Act sections 201, 307, and 309 (as amended by the Energy Policy Act of 2005), and Part 1b of FERC's regulations, FERC authorized the Office of Enforcement to conduct a non-public, formal investigation, with subpoena authority, regarding violations of FERC's regulations, including section 1c.2 (Prohibition of electric energy market manipulation) that may have occurred in connection with, or related to, the 2015-2016 PRA.[143] That investigation is ongoing. On October 20, 2015, FERC staff held a Technical Conference to obtain additional factual information about the following issues: (i) implementation of the current mitigation procedures and reference level calculations, (ii) alternatives to the current mitigation procedures and reference level calculations, (iii) the determination of LCR and CIL, and (iv) the basis for zonal boundaries.[144]

- On December 31, 2015, FERC issued an Order ("the Order") granting in part and denying in part the complaints filed by the IL AG, Public Citizen, SWEC and IIEC. FERC denied the complaints in part and found that complainants had not shown MISO Tariff provisions to be unjust and unreasonable or unduly discriminatory or preferential regarding changes to zonal boundaries, MISO Tariff provisions regarding MISO's capacity construct, and the stakeholder process. FERC directed MISO to submit two compliance filings to revise its Tariff within 30 and 90 days of the Order.

- FERC directed MISO to set the Initial Reference Level for capacity at $0/MW-day.

- FERC directed MISO to determine technology-specific default avoidable costs, which will be based on a formula MISO must develop and add to the Tariff. Recognizing that it would have been difficult for MISO to develop default technology-specific avoidable costs in time for the 2016-2017 PRA, FERC directed MISO to propose such Tariff revisions within 90 days of the date of the order to be implemented prior to the 2017-2018 PRA.[145]

- FERC directed MISO to file Tariff revisions on compliance to ensure that MISO's calculation of CILs accurately reflects counter-flows resulting from capacity exports to neighboring regions. FERC also agreed with an alternative approach and recommendation for calculating CILs provided by the MISO IMM which better reflected the counter flows that capacity exports provide. FERC directed MISO to work with the MISO IMM to file necessary Tariff revisions to implement this recommendation on compliance within 30 days of the date of the Order, to be implemented in time for the 2016-2017 PRA. If MISO had concerns that this directive may result in adverse impacts on reliability, FERC instructed MISO to submit in its compliance filing a demonstration of these concerns and its recommended alternative proposal to be implemented in time for the 2016-2017 PRA.

- FERC denied the complaints with respect to zonal boundaries and did not direct MISO to combine Zones 4 and 5. Nevertheless, FERC encouraged MISO to continue to work with its stakeholders to ensure its zonal boundaries reflect the physical realities of the transmission system.

- In late January and early February of 2016, several parties (including MISO) filed requests for rehearing and/or clarification of the Order.[146]

- In MISO's 30-Day Compliance Filing to the Order ("1st Compliance Filing"), which was filed on January 29, 2016, contemporaneously with the request for rehearing, MISO addressed FERC's compliance directives. i.e. setting the Initial Reference Level at $0/MW-Day, adding language to the Tariff regarding generation resources with facility-specific reference levels, revising the CIL calculation to remove the impact of exports, and revising the LCR calculation to include the benefits of exporting units in supporting local

[143] Investigation into MISO Zone 4 Planning Resource Auction Market Participant Offers, 153 FERC ¶ 61,005 (2015) (Order Initiating Formal Investigation). An order converting an informal, non-public investigation to a formal, non-public investigation does not indicate that FERC has determined that any entity has engaged in market manipulation or otherwise violated any FERC order, rule, or regulation.
[144] Notice of Technical Conference, Docket No. EL15-70-000, *et al.*, at 2-3 (Oct. 1, 2015).
[145] The 90 day compliance filing was extended to June 28, 2016 at the request of MISO and the MISO IMM.
[146] The other parties who filed requests for rehearing were IIEC, IL AG, SWEC, and Electricity Power Association ("EPSA").

resource requirements. Consistent with their request for rehearing MISO proposed to reduce each Zone's LCR by the amount of capacity under MISO's functional control that is exported outside of MISO's footprint (i.e., non-pseudo-tied exports). MISO proposed the following formula to calculate LCR:

LCR = LRR – CIL – non-pseudo-tied exports[147]

- In an order issued on March 18, 2016, ("the 1st Compliance Filing Order") FERC accepted MISO's 1st Compliance Filing, subject to a further compliance filing. FERC also granted MISO's request for clarification and IIEC's and IL AG's request for clarification with respect to going-forward costs and denied all other requests for clarification and rehearing. In the 1st Compliance Filing Order FERC accepted MISO's 1st Compliance Filing to set the Initial Reference Level to $0/MW-Day and also found that MISO had generally complied with the other directives. In the 1st Compliance Filing Order FERC also accepted MISO's proposed revisions to its Tariff, which modifies the formula MISO uses to calculate LCRs.

- In the 1st Compliance Filing Order FERC also granted clarification with respect to concerns raised by IIEC and IL AG regarding whether sunk costs are included in going-forward costs. Specifically, FERC clarified that, for purposes of calculating facility-specific reference levels, going-forward costs do not include sunk costs.

- On April 18, 2016 MISO submitted a compliance filing ("2nd Compliance Filing") to address FERC's directives in the 1st Compliance Filing Order. MISO provided FERC recommended Tariff language changes to comply with FERC's directive to make it clearer that it is the MISO IMM's responsibility to verify opportunity costs used in facility-specific reference levels. MISO also provided revised Tariff language to comply with FERC's directive to clarify that the CIL values posted by MISO on November 1st of each year shall be considered preliminary and subject to change. Also, as directed by FERC, MISO has reflected the revised CIL methodology in the Tariff. The 2nd Compliance Filing is still under FERC's review.

5.2.3 Zonal Deliverability Benefits Filing

MISO has made Tariff changes to the method for allocating Zonal Deliverability Benefits ("ZDBs"). Under the MISO PRA construct, Resources, represented by ZRCs, are paid the Auction Clearing Price in the LRZ where they are located and load, represented by the PRMR pays the Auction Clearing Price in the LRZ where the PRMR resides. Price separation can occur between these zones due to the locational requirements of the PRA when one or more LRZs are importing lower priced capacity from one or more other LRZs within MISO. This can cause MISO to collect more revenue from load than it pays to resources. ZDBs occur as a result of this price separation.

On January 27, 2016, MISO filed with FERC a new methodology for allocating ZDBs. In their filing, MISO noted that the old methodology, which allocated ZDBs pro-rata in an LRZ based upon an LSE's PRMR in comparison with all LSEs' PRMR (i.e. primarily allocating ZDBs based upon the amount of PRMR), may not best reflect the price separation exposure of LSEs from a PRA auction result and is insufficiently precise to preclude undesirable allocations under certain situations. This is because under the MISO PRA mechanism, price separation can occur due to binding constraints in the PRA. Individual LRZs within MISO can have equal Auction Clearing Prices due to the same binding constraint and therefore have the same price separation risk. The old allocation methodology was indifferent to the amount of imports or the price separation between LRZs, making it not effective when there are multiple importing LRZs that all clear at the same Auction Clearing Price due to the same binding constraint.

[147] A pseudo-tied generation resource is one located physically in one reliability authority area but treated electrically as being in another reliability authority area. Pseudo-tied exports are exports from these resources. For example, a MISO resource pseudo-tied to PJM would be a resource physically located in MISO but treated as though it was electrically in PJM. PJM will have dispatch control of the resource even though it is physically located in MISO.

On March 15, 2016, FERC issued a deficiency letter to MISO and requested additional information. On March 25, 2016, MISO submitted a response to FERC's deficiency letter. On April 29, 2016, FERC issued a Letter Order accepting the new method for allocating ZDBs.

5.2.4 Proposed Seasonal and Locational Changes to the MISO Resource Adequacy Construct

MISO is proposing seasonal and locational changes to the MISO Resource Adequacy Construct. The seasonal changes are meant to ensure the transparency of resource adequacy across all seasons and provide flexibility to market participants. The locational changes are meant to reduce volatility in the key inputs to the PRA. Implementation of the seasonal and locational changes is currently scheduled for Planning Year 2019-2020.[148]

Seasonal Changes

Table 5-1 provides a comparison of what is currently proposed versus the status quo.

Table 5-1: Seasonality Proposal Key Differences - Current versus Proposed

Resource Adequacy Requirement Construct	Current State	Proposed
	Annual	Seasonal
Number of Seasons	Summer Based	Two Seasons: Summer and Winter • Summer (June – Sept.) • Winter (October – May)
Capacity Accreditation	Annual	Seasonal: Summer and Winter) • Availability and interconnection service for each season
Demand	Summer Peak Load	Summer and Winter Peak Loads
PRA Deliverables	Annual PRM, LRR, CIL, and CEL	Seasonal: • Summer and Winter PRM • Summer and Winter LRR • Summer and Winter CEL
PRA Design	• Single Auction with Annual Offers • One Annual Auction Clearing Price	• Single Auction with Seasonal Offers • Summer and Winter Auction Clearing Prices
LOLE	Annual LOLE - 0.1 Days/Year	• Summer LOLE - 0.1 Days/Year • Winter LOLE - 0.01 Days/Year

Locational Changes

The MISO Proposal can be summarized as follows:

- Stability

Regarding the need to stabilize locational requirements, MISO notes that unwarranted drivers have been identified for both (i) the PRM and (ii) the CIL and CEL analysis which factor into the LCR analysis. MISO is therefore proposing to stabilize specific inputs and reduce the year over year volatility. Examples of variables contributing to volatility include (i) Load Forecast Uncertainty ("LFU"), (ii) dispatch and load in planning models, (iii)generation retirements, and (iv)new transmission. It is reasonable for the variations in load and generation characteristics to influence the study and its results, but variations in LFU as well as in the external non-firm support may be due to modeling, rather than actual system conditions, and, according to

[148] Based on presentations made to the August 3, 2016 Resource Adequacy Subcommittee ("RASC") meeting, MISO expects to post an updated Design Document of the proposal in the November / December 2016 timeframe.

MISO, changes based on these variations may not be warranted, potentially creating unnecessary and inappropriate volatility. MISO recommends stabilizing the PRM and CIL/CEL by holding external non-firm support constant, reduce volatility in LFU calculation, and require a trigger before re-calculating CIL/CEL

- Creation of External Zones for external Capacity Resources

MISO is proposing the creation of External Resource Zones to appropriately represent and correctly account for the impact of resources outside of MISO on the PRA and to accredit these External Resources in a similar manner to resources internal to MISO and outside of a particular zone. External Resources would no longer count directly towards LCR. External Resources would however be able to directly count towards CIL and CEL. External Resource Zones would facilitate consistency in treatment of external and internal resources through eliminating external resources being modeled in a zone in which they are not physically located. Consideration will be made for Coordination Members. Resources in Coordination Member areas will continue to be considered as part of the MISO zone in which the Transmission Service sinks at the border. A Coordination Member is an entity with a reciprocal tariff with MISO that includes reliability coordination subject to emergency procedures it has developed with MISO. It has also agreed to operate its system in a similar manner, including the agreement to share reserves with MISO during emergency conditions.

- Improved Hedging Mechanisms to Manage Price Separation

To improve hedging mechanisms to manage price separation, MISO recommends implementing Capacity Transfer Rights ("CTRs"). CTRs will be made primarily available to LSEs that enter into long-term supply arrangements and that have firm long-term Transmission Service. This results in allocating the value of the transmission system to LSEs which recognizes that the cost of constructing and maintaining the grid has largely been borne by LSEs. Supply arrangements include ownership of an asset or contractual rights that are at least 5 years in duration. CTRs will be valued based on their "sink" and "source." The value of a CTR is the greater of zero and the "sink" auction clearing price minus the "source" auction clearing price.[149] CTRs will be funded using only excess revenue collected from the PRA (ZDBs). As a result, some CTRs may not be fully funded.

[149] Electrical system modeling uses a "source point" to simulate where electricity it is generated and a "sink point" where it is consumed.

Table 5-2 provides a comparison of what is proposed versus the status quo.

Table 5-2: Locational Considerations Proposal Key Differences - Current versus Proposed

	Current State	Proposed
Stability	Volatility in PRM, CIL and CEL values.	Limit Volatility in PRM, CIL and CEL values: • PRM: Limit volatility caused by unwanted variation in LFU and external non-firm support and provide "bands" or ranges of certainty around out year PRM values. • CIL and CEL: New values re-calculated based on triggers such as threshold impacts of transmission and generation.
External Zones	No External Zones currently modeled.	Create External Zones for resources outside MISO.
Hedges	Zonal Deliverability Hedges	Capacity Transfer Rights.

5.2.5 Resource Adequacy in Restructured Competitive Markets

MISO is proposing the implementation of a competitive retail solution ("CRS") to specifically address the unique resource adequacy needs in restructured competitive retail markets including Illinois and Michigan. MISO proposes to phase in the implementation of the CRS starting in 2018-2019.[150]

MISO's current proposal (yet to be filed with the FERC) has the following features:

- Full Forward Capacity Procurement for Retail Choice Load, Separate from Existing PRA Process.[151]
    - Two structurally separate auctions
        - A new 3-year Forward Resource Auction ("FRA") to procure capacity needs of Retail Choice Load where state or local planning processes are absent.
            - FRA would use a Sloped Demand Curve pricing method.[152]
            - Forward procurement (cleared supply) will be "self-scheduled" into the PRA similar to resources procured by regulated LSEs.
        - Maintains existing PRA and FRAP option for Non-Retail Choice Load.
    - Different Demand Curves Serve Different Needs.
        - FRA will use a "Target Reliability Range" ("TRR") (i.e., Downward Sloping Demand Curve).
            - Sloped Demand Curve will only be used in the FRA.
        - PRA continues to use Vertical Demand Curve to meet balancing needs of LSEs through FRAP and auction clearing for Non-Retail Choice Load.
            - All demand will be modeled using Vertical Demand Curve.
            - Maintains PRA as residual imbalance trading platform.
- Load Participation – Bright-Line Test

[150] On August 8, 2016 MISO Staff informed the Markets Committee of the Board of Directors that MISO will delay the filing date of the CRS proposal from late August, 2016 to November, 2016.
[151] Initial MISO design used hybrid procurement with a sloped demand curve used for both partial forward and residual prompt auctions.
[152] MISO final design utilizes previously FERC-approved demand curve construct (PJM) as basis for design. MISO IMM and multiple stakeholders called for the use of a downward-sloping demand curve to improve price formation for Retail Choice regions.

- Bright-Line Test for Demand.
  - Demand subject to competitive retail access will be required to participate in CRS (subject to evaluation for materiality).
- Materiality Clause
  - Revised test to be based on PRMR instead of LCR
    - Potential Participating Demand's PRMR must be less than 0.5% of the total system wide PRMR.[153]
    - Threshold will be based on having a negligible impact to the system-wide LOLE.
    - Demand evaluated for materiality year over year.
    - Demand that is identified as material will be subject to participation obligations of the FRA and Forward FRAP.
- Elimination of Opt-In Mechanism
  - The Bright-Line Test is the sole determinant of demand participation in CRS.
- Opt-Out Mechanism (Forward FRAP)
  - Fixed requirement.
  - Requires 4 year notification to opt into FRA.
  - Ability for states to establish a compensation mechanism similar to PJM Fixed Resource Requirements ("FRR").

- Participation – Supply
  - Market Power Monitoring and Mitigation.
    - Resources physically located within an LRZ with Participating Demand will be subject to existing Module D provisions for the FRA.
    - Resources physically located outside an LRZ (s) with Participating Demand may elect to participate.
    - MISO will work with IMM to identify and develop additional mechanisms as necessary.
  - Safe Harbor
    - LSEs serving non-Participating Demand that have resources in an LRZ with Participating Demand may exempt those resources from evaluation for physical withholding.
    - Up to the most recent PRMR from the last cleared PRA.
    - Requires attestation from an officer of the company.
    - Includes a process to account for adjustments due to new resource exit and increases in forecasted demand.
    - Adjustments are subject to review by MISO.

Table 5-3 provides a comparison of what is proposed under the MISO proposal versus the status quo.

[153] For example, if the system wide PRMR is 136,000, the Materiality Threshold is 136,000*0.005 = 680 MW. If the coincident peak demand reported by the EDC is 400 MW, and the PRM is 7%, the PRMR is 400*1.07 = 428 MW. Application of materiality test: 428 MW is not greater than or equal to 680 MW – therefore LRZ will not have demand represented in FRA.

Table 5-3: Competitive Retail Solution Proposal Key Differences - Current versus Proposed

	Current State	Proposed
Capacity Auctions	PRA	Two Structurally Separate Auctions: • 3-Year FRA for Retail Choice Load in CRAs. • PRA for Non-Retail Choice Load
Auction Demand Curves	Vertical Demand Curve for PRA	• Sloped Demand Curve for FRA • Vertical Demand Curve for PRA
Load Participation	• No Bright Line Test for Load • Load can opt out through FRAP	• Bright-Line Test for Load. • CRA Load will be required to participate subject to Materiality Clause. • Bright-Line Test is sole determination of participation in CRS. • Load can opt out through FRAP.
Supply Participation	All resources subject to market power and mitigation procedures (Module D).	• Resources physically located within an LRZ with Participating Demand will be subject to existing Module D provisions for the FRA. • Resources located outside an LRZ (s) with Participating Demand may elect to participate. • Safe Harbor provisions for LSEs serving Non-Participating Demand that have resources in an LRZ with Participating Demand (LSEs may exempt those resources from evaluation for physical withholding).

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."[154]

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.*[155]

This Chapter discusses and assesses risk in the supply portfolio, as well as tools and strategies for mitigating them. 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. Section 6.1.4 describes types of contracts and hedges that can be used to manage supply risk. Those products may be thought of as being used to build a supply portfolio. 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 have to do so by selling previously purchased hedges over-the-counter.

Section 6.6.2 addresses the cost and uncertainty impacts of these 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 are trued up after the fact through the Purchased Electricity Adjustment ("PEA").[156] Prior to the 2016-2017 delivery year, MidAmerican provided power and energy to its eligible Illinois customers from MidAmerican owned generation. The energy pricing for MidAmerican customers in Illinois has been recovered through base rates regulated by the Illinois Commerce Commission. Starting with the 2016-2017 delivery year, MidAmerican pricing for its Illinois customers also includes the energy obtained in IPA procurements, and that will be reflected through a cost recovery process similar to what is used by Ameren Illinois and ComEd. Section 6.5 provides a historical summary of the Ameren Illinois and ComEd PEA rates as a guide to the historical impact of risk factors. 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. Finally, Section 6.7 addresses demand management.

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.

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[154] 20 ILCS 3855/1-20(a)(1).

[155] 220 ILCS 5/16-111.5(b)(3)(vi).

[156] 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's Rider PER (Purchased Electricity Recovery).

6.1.1 Volume Risk

The accuracy of load forecasts directly impacts volume risk. 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.

6.1.2 Price Risk

The price the Ameren Illinois and ComEd supply customers pay for electricity consists primarily of the price of energy procured in the forward and spot markets, the cost of capacity to meet resource adequacy requirements, and the cost of delivery, plus additional charges related to RPS compliance. MidAmerican customers in Illinois pay the energy and capacity costs associated with the portion of the MidAmerican resources that are allocated to serving its Illinois load. The requirements of MidAmerican's Illinois customers that exceed this resource allocation are obtained through the IPA's procurement process starting with the 2016 Procurement Plan. The primary risk factors that contribute to price risk include the costs of electric energy, real-time balancing, capacity, ancillary services, transmission including congestion, and correlation with volume risk factors.

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 in the two prior years. 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 that the current price of an ARES or municipal aggregation offer. 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.

6.1.3 Residual Supply Risk

Hedging imperfection can contribute to supply risks through mismatches in procurement supply shape, supply delivery points and customer load locations, or the intermittent nature of renewable energy sources. The standard on-peak and off-peak block energy products procured by the IPA do not reflect 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 peak and off-peak periods. Because of this variation, if the average 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. The cost to cover the intermittent output from renewable resources in the supply portfolio may not be hedgeable and therefore can result in residual supply risk as well.

6.1.4 Basis Differential Risk

Basis differential risk relates to the uncertainty that the price of energy delivered at a given delivery 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 Load Serving Entity's ("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 residual price risk and other risks, such as weather risk.

ComEd and Ameren Illinois divested their generating plants to unregulated affiliates or third parties. They have no contracts for unit-specific physical delivery, other than certain Qualifying Facilities (as designated under the federal Public Utilities Regulatory Practices Act) contracts. As the utilities do not purchase and take title to electricity, the utilities' supply positions, other than RTO spot energy, are exclusively price hedges. MidAmerican has retained the resources that serve its Illinois customers, most of which 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 was 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 the energy, capacity and renewable resources that is not met by the allocated MidAmerican resources. Following the approach started for the 2016 Plan, under the 2017 Procurement Plan, the IPA will procure the net requirements between MidAmerican's eligible retail customer load and the MidAmerican controlled generation allocated to its Illinois customers.

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, That is, 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 LSE still needs 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 payable risks, but those are not associated with the supply portfolio.

Each RTO charges a uniform day-ahead price for all energy scheduled 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 LSE pays the real-time price; and if demand is less than the day-ahead schedule, the LSE is credited 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, 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 reduction.[157]

[157] 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.

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

- As-available
- Baseload
- Dispatchable

Unit-Independent Hedges.

- 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.[158] 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.[159] 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.[160] The most natural evidence of competitiveness is the breadth of participation, although other evidence may be possible as well.

Hedges most suitable for use by the Agency would be 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 control its risk exposure. Availability of information on current prices and the price history of similar products help 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 hedges in 50 MW increments. The IPA began using 25 MW increments and a second, fall 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

[158] There has been substantial debate in the approval of prior 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." ICC Docket No. 14-0588, Final Order dated December 17, 2014 at 114. Since that decision, the IPA has not been made 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 continued success of its procurement approach in producing highly competitive service rates for Ameren Illinois, MidAmerican and ComEd eligible retail customers.

[159] 220 ILCS 5/16-111.5(b), (e), (f).

[160] 220 ILCS 5/16-111.5(f).

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 and may not be compatible with such a low level of transparency.

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 less liquid than near term contracts, however. The Agency would seek to obtain competitive pricing on such contracts if it were to incorporate them in its portfolio. However, it may 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 either in an open outcry auction 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.

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.

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's 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 was 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 Dodd-Frank Act of 2010 (specifically Title VII). Under this 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."[161] 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.
- 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 to FERC Order 717.[162]
- To date, the utilities have scheduled excess supply in their portfolios, or made up supply deficits in the RTOs' day-ahead markets with residual balancing occurring in the RTOs' real-time markets. This has been the dominant mode of portfolio rebalancing.
- As an alternative form of rebalancing, the Agency could conduct "reverse RFP" procurement events, in which the bids are to buy rather than sell forward hedges. The Agency does not believe that it has the authority to sell excess supply via its authority to "conduct competitive procurement processes" under 20 ILCS 3855/1-20(a)(2).
- The Agency could conceivably issue an RFP to purchase derivative products, such as put options on forward hedges, which would have a similar risk reduction effect to selling forwards. This may avoid legal and contractual difficulties associated with selling forward hedge contracts. This approach would also require the utilities to ensure they had regulatory approval to exercise the options after purchasing them, and the employees who exercise the option could become classified as part of a "marketing function." The Agency does not envision entering into derivative contracts for rebalancing purposes.
- The Agency could conduct multiple procurement events in a year if the rebalancing required is to increase the supply under contract. Since 2014, the IPA has conducted two procurements each year, one in the spring and the other 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 Purchased Electricity Adjustment ("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

161 220 ILCS 5/16-111.5(b)(4).
162 125 FERC ¶ 61,064, Oct. 16, 2008.

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 and ComEd. MidAmerican will recover the costs of power and energy procured by the IPA through tariffs Implementing Rider PE – Purchased Electricity which were approved by the ICC in February 2016.[163]

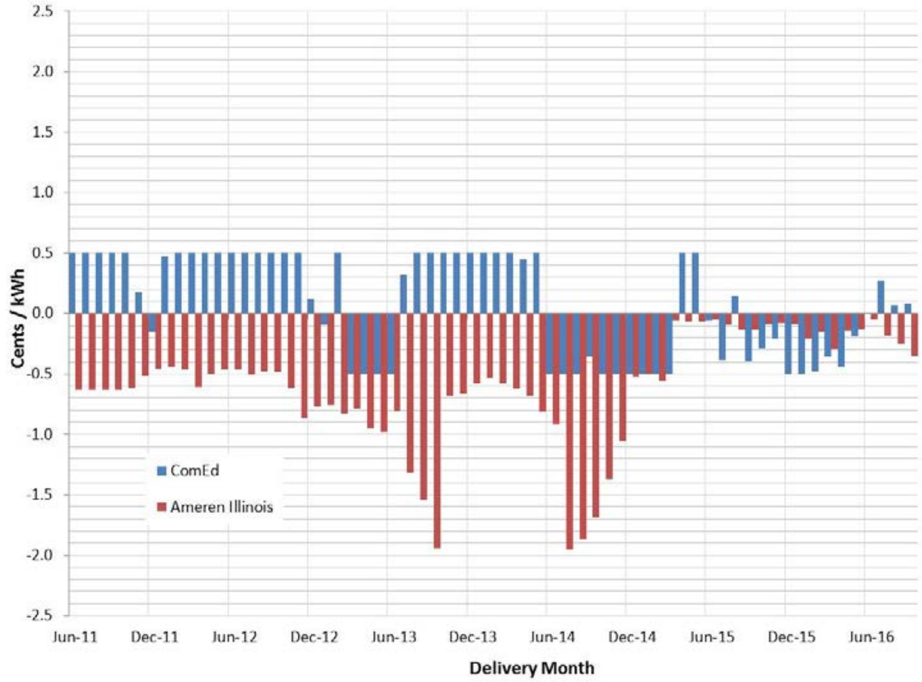
The PEA provides some guidance as to the amount by which the complete set of risk factors caused the cost of energy supply to differ from the estimate—in other words, the impact of risk. Figure 6-1 shows how the PEAs for Ameren Illinois and ComEd have changed over the last five years. While Ameren Illinois's PEAs have been generally "negative" (i.e., operating as a credit to customers) over this period, ComEd's have been "negative" as well as "positive" (i.e., operating as charge to customers), and recently have shown more volatility. ComEd has voluntarily limited its PEA to move between +0.5 cents/ kWh and -0.5 cents/kWh, and the figure shows that ComEd's PEA has oscillated between those limits.

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 two months in the spring of 2015. This was 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 and June 2016, but reflected credits for most of the recent months ending in June 2016.

From July 2013 through September 2013 and for 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 subsequently settled favorably to customers within the MISO balancing markets. This drove an over-collection from eligible retail customers during the previous winters and the large 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.

[163] See Docket No. 15-0564, Final Order dated February 24, 2016.

Figure 6-1: Purchased Electricity Adjustments in Cents/kWh, June 2011 – September 2016



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

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

6.6.1 Historic 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 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 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 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 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 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 current year and for on-peak hours for June, September, and October delivery in the current 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 50% for all months (June-May) of the following year for the September procurement event, 37.5% for all months of the following year for the April event, 25% for all months of the second year out for the September event, and 12.5% for all months of the second year out for the April 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 cumulative hedge ratios for various delivery months, effective at the next to last scheduled event prior to delivery.

For the 2017 Procurement Plan, the IPA proposes to continue the use of two procurement events to be held in the spring and fall. The hedge ratios are proposed to remain at the values set for the 2016 Plan.

The 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 FutureGen agreement), 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

Given the volatility in forward energy prices from month to month and within months experienced in the last several years, the IPA investigated the merit of considering alternative procurement schedule strategies with the goal of further minimizing the volatility of the resulting portfolios of contracts for each delivery month in developing its 2016 Plan.

For the 2016 Plan, the IPA conducted a detailed analysis related to procurement scheduling and volatility.[164] The results indicated that the closer the procurement events are held to the product delivery date, the greater the impact of volatility on the products procured. The on-peak convenience volatility curves shown in this analysis demonstrated these results. However, other factors also impact the scheduling of procurement events relative to delivery timing and may result in reasonable decisions to hold procurement events in close proximity to product delivery dates.

The results of the 2016 Plan analysis suggested that volatility, as measured by the standard deviation of daily forward prices within a trade month, is not significantly different from trade month to trade month and is

[164] See 2016 IPA Procurement Plan at 71-80.

generally somewhat higher in any trade month for delivery in a summer month (e.g., July) than for delivery than other months. High volatility for winter delivery months (e.g., January) is a recent development.

The cost to eligible retail customers for qualified service in a given month is driven by the average price paid for blocks of on-peak and off-peak energy secured under a 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 more random draw of the forward price on the days in which components of the portfolio are procured. The IPA performed a "backcast" analysis to study the effects of different procurement schedules for the on-peak energy component of the monthly portfolios for October 2014 through September 2015 delivery using the PJM Northern Illinois Hub forward price data. A Monte-Carlo simulation was conducted with 10,000 iterations. In each iteration a forward price was drawn from a normal distribution for each delivery month and from each designated event date range (one to two months of trade days), and a weighted average portfolio cost for each delivery month under each procurement schedule, based on the designated target levels was calculated. The distributions over all iterations of the portfolio average costs were analyzed to determine means and standard deviations.

While the IPA did not include modeling of seasonal futures prices in the 2016 Plan Monte Carlo simulation, it appears that the fairly stable volatility of average futures 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.

Based on this analysis, the IPA sees no reason to change the energy procurement schedule and approach for its 2017 Plan from the approach established in the 2015 Plan and utilized again for the 2016 Plan.

6.7 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. 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 DR and EE resources similarly to other capacity providing resources for operational planning purposes.

FERC Order No. 745 requires ISOs 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 DR 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.[165] Chapter 7 of this plan provides details and additional discussion regarding demand response resources.

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

7 Resource Choices

This Chapter of the Procurement Plan sets out recommendations for the resources to procure 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. Procurement of Renewable Resources, including wind, solar and distributed generation is considered separately in Chapter 8. Procurement of incremental energy efficiency programs and measures is also considered separately in Chapter 9.[166]

7.1 Energy

7.1.1 Energy Procurement Strategy

The IPA recommends maintaining the energy procurement strategy utilized for the 2016 Procurement Plan as explained below.

- The IPA procurement strategy involves the procurement of hedges to meet a portion of the hedging requirements over a three-year period and includes two procurement events in which the July and August peak requirements will be hedged at 106%, while the remaining peak and off-peak requirements will be hedged at 100%. In the spring procurement event, 106% of the July and August expected peak, 100% of the July and August off-peak, 100% of the June and September peak and off-peak, and 75% of the October through May peak and off-peak requirements for the 2017-2018 delivery year will be targeted for procurement. The fall procurement event will bring the targeted hedge levels to 100% for October through May of the 2017-2018 delivery year. A portion of the targeted hedge levels for the 2018-2019 and the 2019-2020 delivery years of 50% and 25%, respectively, will be acquired spread on an equal basis in the spring and fall procurement events.

The strategy is summarized in Table 7-1

Table 7-1: Summary of Energy Procurement Strategy for all Utilities[167]

Spring 2017 Procurement			Fall 2017 Procurement		
June 2017-May 2018 (Upcoming Delivery Year)	Upcoming Delivery Year+1	Upcoming Delivery Year+2	October 2017-May 2018	Upcoming Delivery Year + 1	Upcoming Delivery Year + 2
June 100% peak and off peak July and Aug. 106% peak, 100% off peak Sep. 100% peak and off peak Oct. - May 75% peak and off peak	37.5%	12.5%	100%	50%	25%

7.1.2 Energy Procurement Implementation

The following tables and figures were constructed using the July 2016 base load forecasts (which exclude incremental energy efficiency programs) to provide <u>indicative</u> procurement values for the 2017-2018 delivery year. The actual target procurement volumes used for the Spring and Fall 2017 procurements will be calculated using the March 2017 and the July 2017 updated load forecasts respectively.[168] These forecasts are expected to include approved energy efficiency programs for both Ameren Illinois and ComEd. The following

[166] The 2013 through 2016 Plans included the consideration of incremental Energy Efficiency programs in Chapter 7 as part of the Resources Choices discussion. For the sake of clarity, in the 2017 Plan that consideration of Energy Efficiency programs has been moved to its own Chapter 9.
[167] Table shows the cumulative percentage of load to be hedged by the conclusion of the indicated procurement events.
[168] In updating the load forecasts, the utilities are authorized to incorporate methodological refinements to their forecasts, provided that any such refinements are subject to the review and consensus of the IPA, ICC Staff, the Procurement Monitor, and the applicable utility.

tables are calculated assuming no LTPPA curtailments during the delivery periods, and the anticipated procurement volumes are rounded up or down to the nearest 25 MW block.[169]

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 2020-2021 and 2021-2022) in this Procurement Plan. Therefore, the tables and figures that follow only cover Delivery Years 2017-2018, 2018-2019, and 2019-2020.

[169] 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

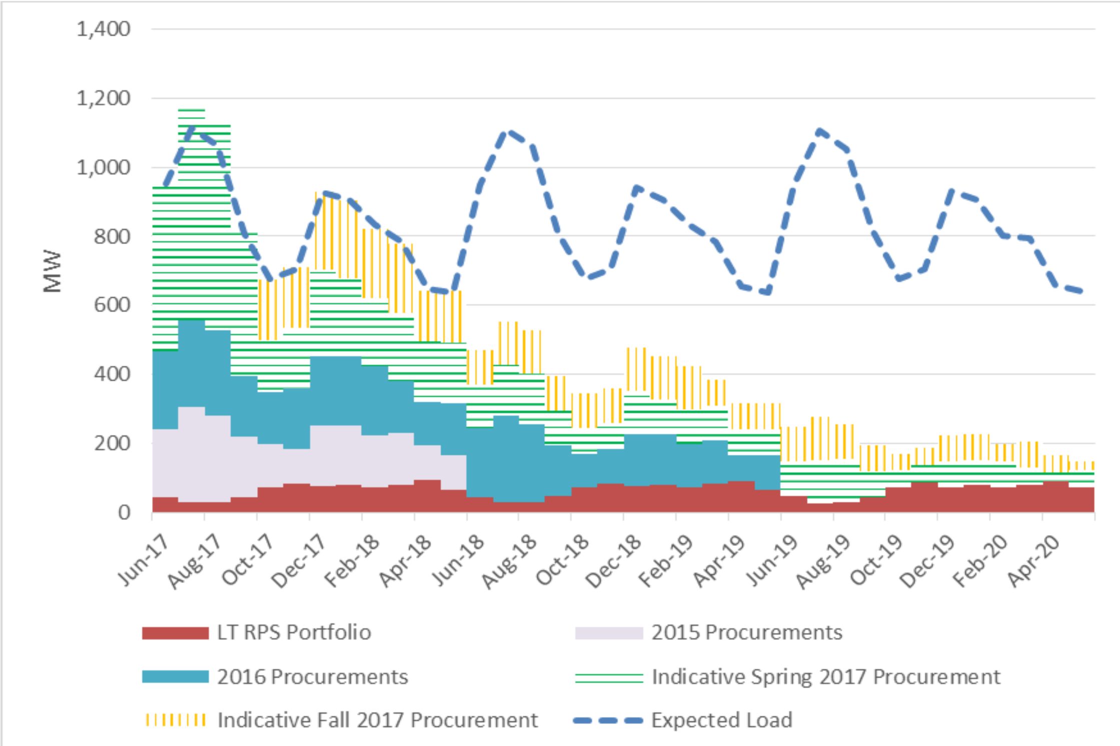


Figure 7-2 Ameren Illinois Off-Peak Energy Supply Portfolio and Load

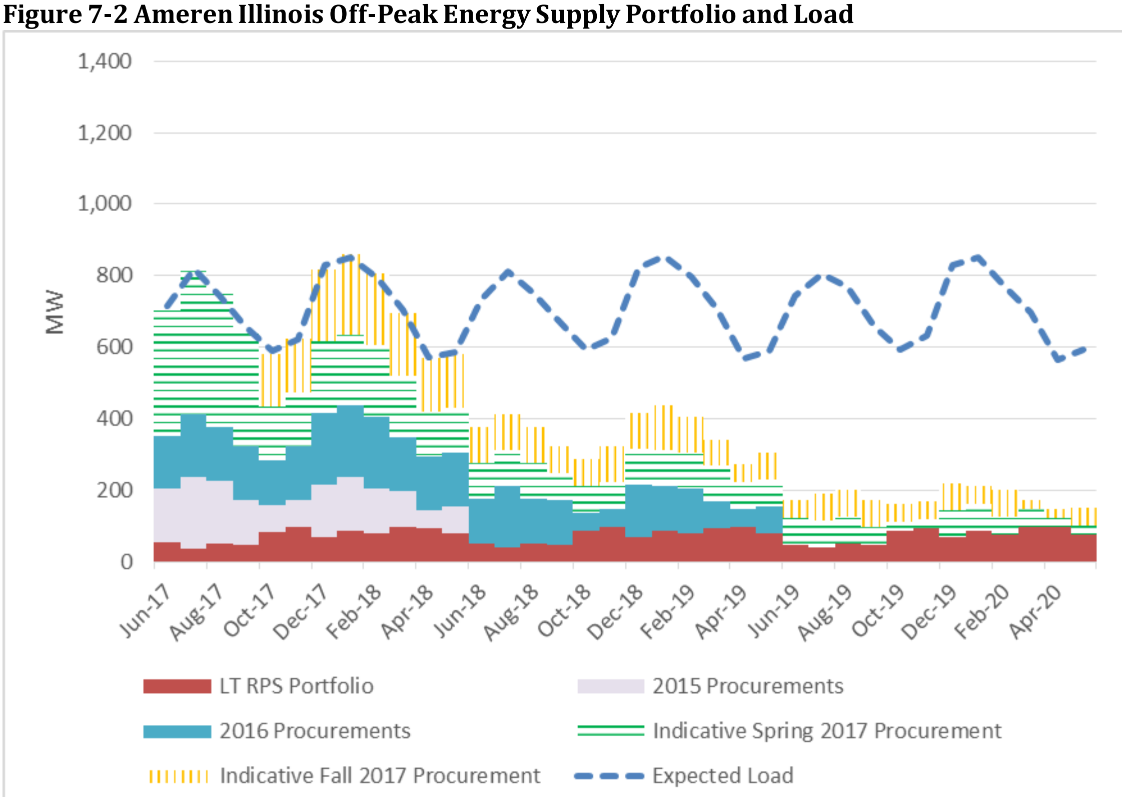


Table 7-2: Ameren Illinois 2017 Spring and Fall Procurements

Delivery Month	Anticipated Spring 2017 Purchases (MW)		Anticipated Fall 2017 Purchases (MW)	
	Peak	Off-Peak	Peak	Off-Peak
Delivery Year 2017-2018				
June-17	475	350	0	0
July-17	625	400	0	0
August-17	600	375	0	0
September-17	425	325	0	0
October-17	150	150	175	150
November-17	175	150	175	150
December-17	250	200	225	200
January-18	225	200	225	225
February-18	200	200	200	200
March-18	200	175	200	175
April-18	175	125	150	150
May-18	175	125	150	150
Delivery Year 2018-2019				
June-18	125	100	100	100
July-18	150	100	125	100
August-18	150	100	125	100
September-18	100	75	100	75
October-18	75	75	100	75
November-18	75	75	100	100
December-18	125	100	125	100
January-19	100	100	125	125
February-19	100	100	125	100
March-19	100	100	75	75
April-19	75	75	75	50
May-19	75	75	75	75
Delivery Year 2019-2020				
June-19	100	75	100	50
July-19	125	75	125	75
August-19	125	75	100	75
September-19	75	50	75	75
October-19	50	25	50	50
November-19	50	25	50	50
December-19	75	75	75	75
January-20	75	75	75	50
February-20	75	50	50	75
March-20	50	50	75	25
April-20	25	25	50	25
May-20	50	25	25	50

Figure 7-3 ComEd Peak Energy Supply Portfolio and Load

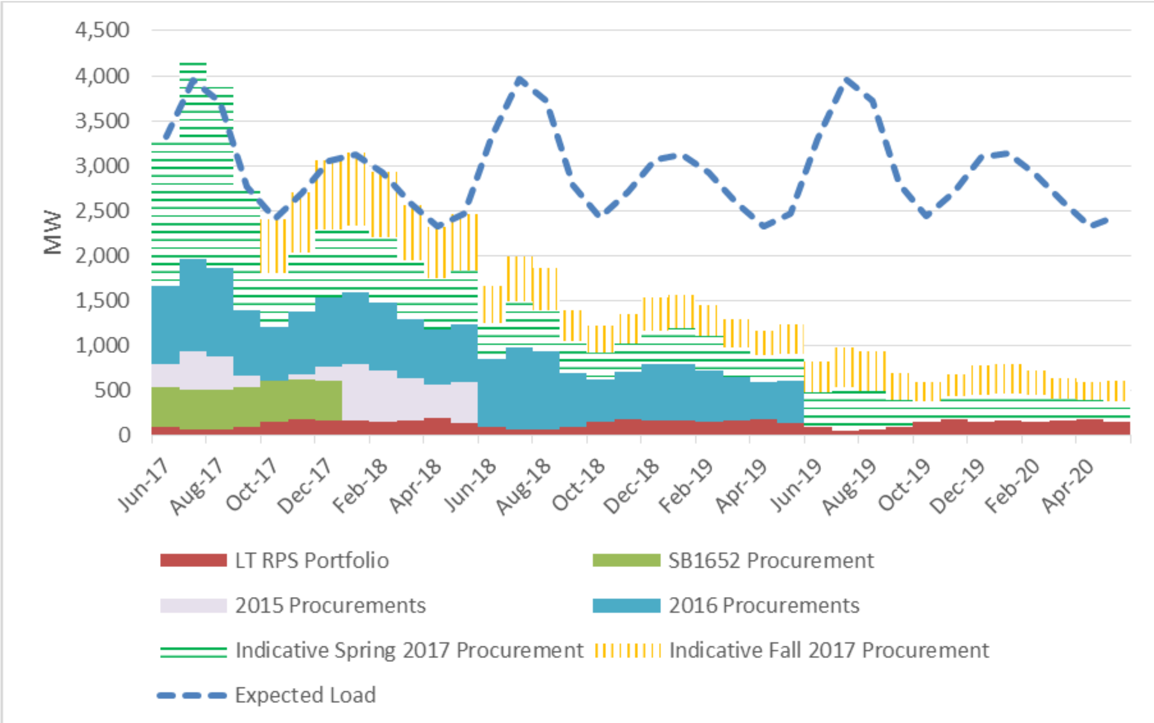


Figure 7-4 ComEd Off-Peak Energy Supply Portfolio and Load

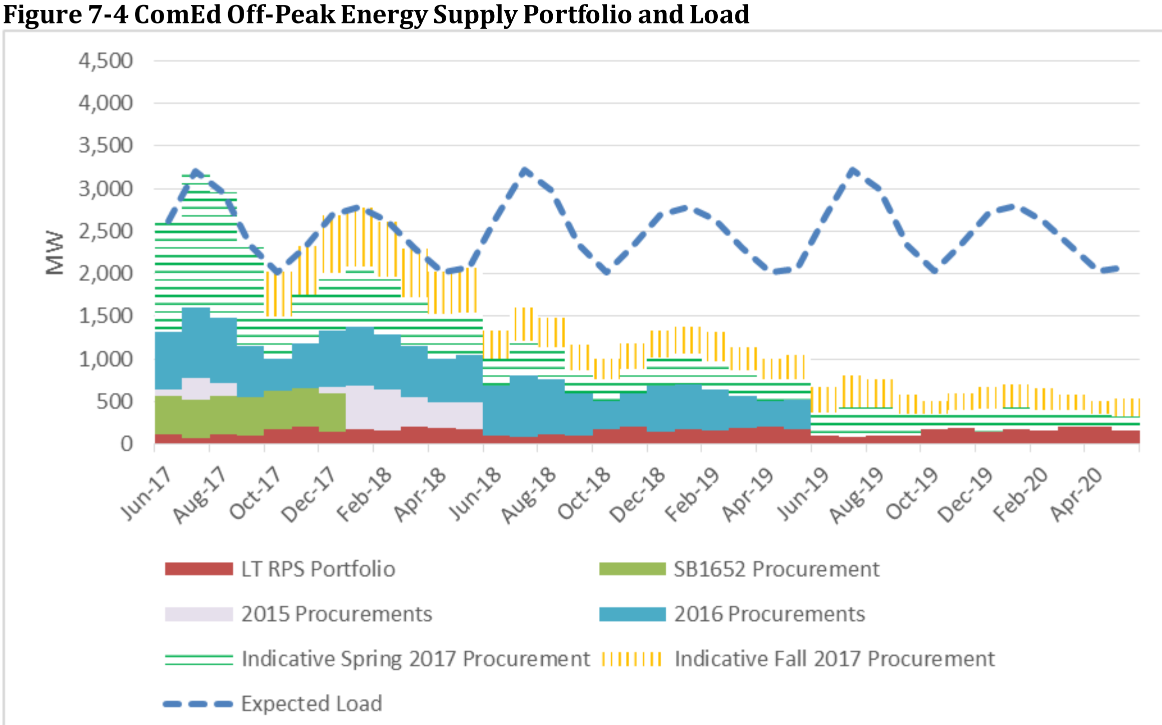


Table 7-3: ComEd 2017 Spring and Fall Procurements

Delivery Month	Anticipated Spring 2017 Purchases (MW)		Anticipated Fall 2017 Purchases (MW)	
	Peak	Off-Peak	Peak	Off-Peak
Delivery Year 2017-2018				
June-17	1,650	1,300	0	0
July-17	2,225	1,600	0	0
August-17	2,075	1,475	0	0
September-17	1,375	1,175	0	0
October-17	600	500	600	525
November-17	650	575	675	575
December-17	750	675	775	675
January-18	750	700	800	700
February-18	725	675	725	650
March-18	650	575	625	575
April-18	575	525	575	500
May-18	600	500	625	525
Delivery Year 2018-2019				
June-18	400	325	425	325
July-18	500	400	500	400
August-18	450	375	475	350
September-18	350	275	350	300
October-18	300	250	300	250
November-18	325	275	325	300
December-18	375	325	375	325
January-19	400	350	375	325
February-19	375	325	350	350
March-19	325	300	325	275
April-19	300	250	275	250
May-19	300	250	325	275
Delivery Year 2019-2020				
June-19	375	275	350	300
July-19	475	350	450	375
August-19	425	325	450	325
September-19	300	250	300	225
October-19	225	175	225	150
November-19	250	200	250	200
December-19	300	275	325	250
January-20	300	250	325	275
February-20	300	250	275	250
March-20	250	200	225	175
April-20	200	150	200	150
May-20	225	175	225	200

Figure 7-5 MidAmerican Peak Uncapped Energy Supply Portfolio and Load

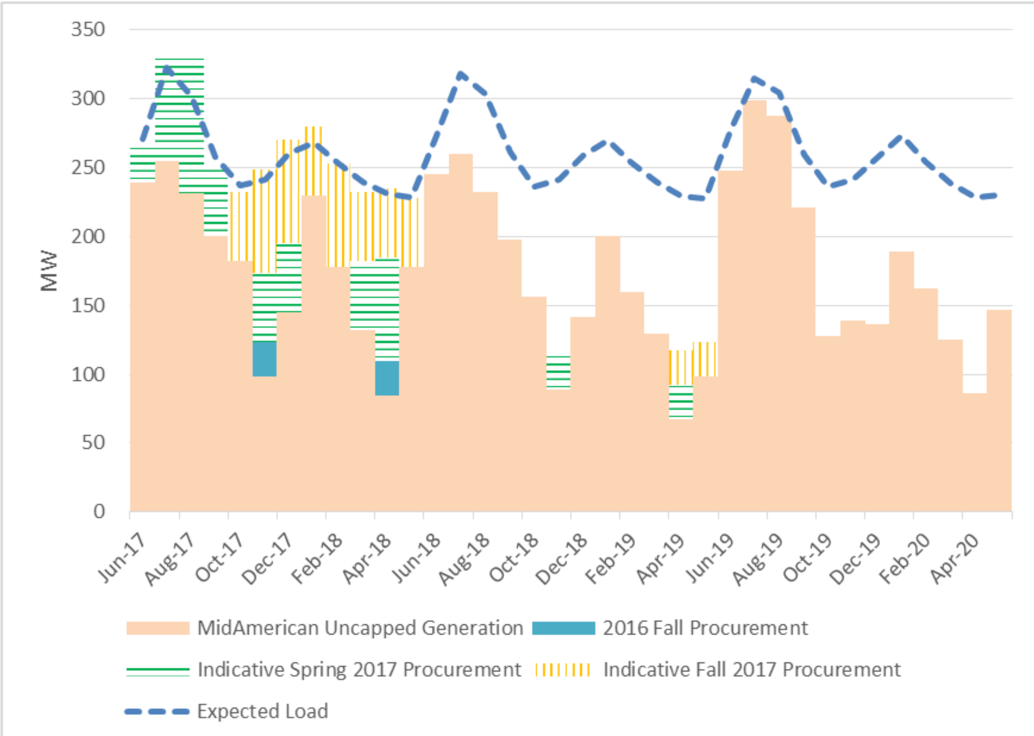


Figure 7-6 MidAmerican Uncapped Off-Peak Energy Supply Portfolio and Load

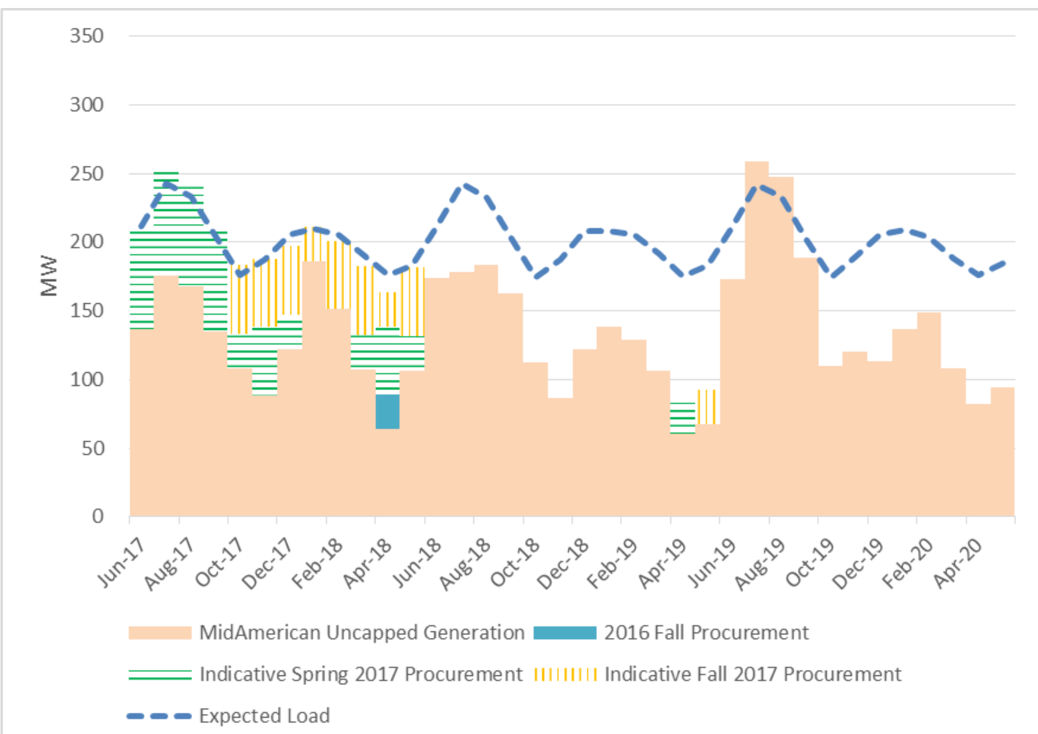


Table 7-4: MidAmerican 2017 Spring and Fall Procurements

Delivery Month	Anticipated Spring 2017 Purchases (MW)		Anticipated Fall 2017 Purchases (MW)	
	Peak	Off-Peak	Peak	Off-Peak
Delivery Year 2017-2018				
June-17	25	75	0	0
July-17	75	75	0	0
August-17	100	75	0	0
September-17	50	75	0	0
October-17	0	25	50	50
November-17	50	50	75	50
December-17	50	25	75	50
January-18	0	0	50	25
February-18	0	0	75	50
March-18	50	25	50	50
April-18	75	50	50	25
May-18	0	25	50	50
Delivery Year 2018-2019				
June-18	0	0	0	0
July-18	0	0	0	0
August-18	0	0	0	0
September-18	0	0	0	0
October-18	0	0	0	0
November-18	25	0	0	0
December-18	0	0	0	0
January-19	0	0	0	0
February-19	0	0	0	0
March-19	0	0	0	0
April-19	25	25	25	0
May-19	0	0	25	25
Delivery Year 2019-2020				
June-19	0	0	0	0
July-19	0	0	0	0
August-19	0	0	0	0
September-19	0	0	0	0
October-19	0	0	0	0
November-19	0	0	0	0
December-19	0	0	0	0
January-20	0	0	0	0
February-20	0	0	0	0
March-20	0	0	0	0
April-20	0	0	0	0
May-20	0	0	0	0

7.2 Capacity

7.2.1 Capacity Procurement Strategy

7.2.1.1 ComEd

Prior procurement plans, including the 2016 Procurement Plan, have recommended that ComEd obtain its capacity needs through the PJM-administered capacity market. For the 2017 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 2015 and 2016 Procurement Plans recommended procurement of at least a portion of the Ameren Illinois capacity needs through bilateral capacity purchases with the remainder of the capacity needs procured from the MISO PRA. As outlined below (and further discussed in Section 5.2), given the current uncertainty around the design of the MISO PRA and the resulting effects of any design changes, the IPA recommends deferring any decision regarding the capacity procurement strategy for the 2019-2020 planning year and beyond until next year's Plan.

The IPA proposes the following capacity procurement strategy:

- As approved under the 2016 Procurement Plan, for the 2017-2018 Planning Year, 75% of the Ameren Illinois Capacity would be procured through an RFP in the fall of 2016, with the remaining 25% being procured in the MISO PRA;
- As approved under the 2016 Procurement Plan, for the 2018-2019 Planning Year, 25% of the Ameren Illinois Capacity would be procured through an RFP in fall of 2016. 50% will be procured through an RFP in the fall of 2017. The remaining 25% will be procured in the MISO PRA; and
- For the 2019-2020 Planning Year, the decision will be deferred until next year's Plan.

Table 7-6 summarizes the proposed capacity procurement for Ameren Illinois.

7.2.1.3 MidAmerican

MidAmerican has elected to procure power and energy through the IPA procurement process for the incremental amount of load that is not currently served or forecasted to be served in Illinois by MidAmerican-owned Illinois jurisdictional generation. As part of that election, MidAmerican provided its forecasted load and capability, a summary of which is presented in Table 7-5 below.

The IPA notes that the magnitude of the proposed capacity procurements for MidAmerican is small relative to its capacity requirements, as shown below. Also, consistent with the discussion regarding the procurement strategy for ComEd, the IPA recommends that MidAmerican obtains 100% of its forecast capacity shortfall from its RTO's capacity market, MISO PRA.

Table 7-5: Summary of MidAmerican Load and Capability

	2017-2018	2018-2019	2019-2020	2020-2021	2021-2022
Coincident Peak Load	434	436	439	441	444
Reserves	33	33	33	34	34
Coincident Peak Load with Reserves	467	469	472	475	477
UCAP MW Total Net Capability	395	395	395	397	397
Capacity Shortfall	71	74	77	78	81

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 2017 Procurement Plan to assure reliability over the planning horizon. As indicated below, for the 2017-2018 and 2018-2019 planning years, the IPA recommends the procurement of part of the capacity needs through bilateral capacity purchases. The remainder of the capacity needs for these planning years will be procured from the MISO PRA. A decision regarding a capacity procurement proposal for the 2019-2020 planning year will be deferred until next year's Plan.

Table 7-6: Summary of Capacity Procurement for Ameren Illinois[170]

June 2017-May 2018 (Upcoming Planning Year)[171]	June 2018-May 2019[172]	June 2019-May 2020
75% RFP in Fall 2016 25% MISO PRA*	25% RFP in Fall 2016 50% RFP in Fall 2017 25% MISO PRA**	To Be Determined In Next Year's Plan

* MISO Auction is expected to clear in April 2017.
** MISO Auction is expected to clear in April 2018.

7.2.2.2 ComEd

For ComEd, the IPA concludes that it does not need to include any extraordinary measures in the 2017 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 2017-May 2018 (Upcoming Planning Year)	June 2018-May 2019	June 2019-May 2020	June 2020-May 2021
100% PJM RPM Auctions*	100% PJM RPM Auctions*	100% PJM RPM Auctions*	100% PJM RPM Auctions**

* PJM RPM Base Residual Auctions for 2017-2018, 2018-2019 and 2019-2020 have already cleared.
** The 2020-2021 Base Residual Auction will likely be held in May 2017.

170 Table shows the incremental percentage of capacity requirements to be hedged or purchased in the indicated procurement events.
171 Procurement approved in the 2016 Procurement Plan.
172 Procurement approved in the 2016 Procurement Plan.

7.2.2.3 MidAmerican

For MidAmerican, the IPA concludes that it does not need to include any extraordinary measures in the 2017 Procurement Plan to assure reliability over the planning horizon. The IPA recommends that MidAmerican continue to procure 100% of its forecast capacity shortfall for the 2017-2018, 2018-2019 and 2019-2020 planning years from the upcoming annual MISO PRAs to be held in April of 2017, 2018 and 2019 respectively, as indicated below.

Table 7-8: Summary of Capacity Procurement for MidAmerican

June 2017-May 2018 (Upcoming Planning Year)	June 2018-May 2019	June 2019-May 2020
100% of expected shortfall from MISO PRA*	100% of expected shortfall from MISO PRA**	100% of expected shortfall from MISO PRA***

* MISO Auction is expected to clear in April 2017.
** MISO Auction is expected to clear in April 2018.
***MISO Auction is expected to clear in April 2019.

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.[173]

ComEd provided information regarding its existing demand response programs for 2016-2017 which include:

- Direct Load Control ("DLC"): ComEd's residential central air conditioning cycling program is a DLC program with 73,000 customers with a load reduction potential of 87 MW (ComEd Rider AC).
- 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 1,163 MW of potential load reduction (ComEd Rider VLR).
- 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 roughly 5 MW of price response potential.

[173] 220 ILCS 5/8-103(c).

- 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 158,000 customers in 2016. ComEd sold 48 MW of capacity from the program into the PJM capacity auction for the 2017-2018 Planning Year increasing to 85 MW in the 2019-2020 Planning 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 Commission's Interim Order in Docket No. 13-0105, Ameren Illinois offers a Peak Time Rebate program (Rider PTR). The program currently has 10,450 customers and Ameren Illinois sold 2.3 MW of capacity in the MISO PRA for the 2017-2018 Planning 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. In addition, there is a potential for load displacement due to curtailment of customers on an interruptible rate. Based on the customer enrollment, MidAmerican estimates its potential total capacity of Demand Response (DR) at 18.9 MW.

The IPA does not propose any procurement of demand response programs from eligible retail customers in the 2017-2018 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." Section 16-111.5B of the Public Utilities Act explicitly extends energy efficiency program participation to potentially "eligible retail customers" to accommodate the challenges created by customer switching. In contrast, Section 16-111.5(b)(3)(ii)(A) contains no such provision, and 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 Rebate (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.[174] As a part of the goal, the Plan must also include electricity

[174] 20 ILCS 3855/1-75(d).

generated from clean coal facilities.[175] While there is a broader definition of "clean coal facility" contained in the definition section of the IPA Act[176], Section 1-75(d) describes two special cases: the "initial clean coal facility"[177] 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 ("retrofit clean coal facility").[178] Currently, the IPA is unaware of any facility meeting the definition of an "initial clean coal facility" that has announced plans to begin operations within the next five years.

7.5.1 FutureGen 2.0

In Docket No. 12-0544, the Commission approved inclusion of FutureGen 2.0 as a retrofit clean coal facility starting in the 2017-2018 delivery year.[179] On July 22, 2014, an Illinois appellate court upheld the Commission's decision to require ComEd and Ameren Illinois to recover FutureGen sourcing agreement costs through a competitively-neutral retail distribution charge applicable to all utility distribution customers (including ARES customers).[180]

In early February 2015, the U.S. Department of Energy (DOE) announced the suspension of federal funding, $1 billion in funding under the American Recovery and Reinvestment Act of 2009 (ARRA), for the Future Gen 2.0 project, indicating that the project had insufficient time to be completed by the ARRA funding expiration in September 2015. The DOE suspension of funding resulted in the termination of project development for FutureGen 2.0 in early 2016, and 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.[181] FutureGen has since terminated the prior-approved FutureGen 2.0 Sourcing Agreements with the utilities.

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[175] 20 ILCS 3855/1-75(d)(1).
[176] 20 ILCS 3855/1-10.
[177] Id.
[178] 20 ILCS 3855/1-75(d)(5).
[179] See Docket No. 12-0544, Final Order dated December 19, 2012 at 228-237; see also Docket No. 13-0034, Final Order dated June 26, 2013 ("Phase II" approving sourcing agreement as required in Docket No. 12-0544).
[180] Commonwealth Edison Co. v. Illinois Commerce Commission, et al., 2014 IL App (1st) 130544, July 22, 2014.
[181] Commonwealth Edison Co. v. Illinois Commerce Commission, et al., 2016 IL 118129, May 19, 2016.

8 Renewable Resources Availability and Procurement

This Chapter focuses on the procurement of renewable resources on behalf of eligible retail customers and provides informational guidance on use of the Renewable Energy Resources Fund ("RERF"), which contains alternative compliance payments made by ARES as part of their RPS compliance obligations. Renewable energy resource procurement on behalf of eligible retail customers is subject to targets for purchase volumes (represented as a percentage of eligible retail customer load) found in Section 1-75(c)(1) of the IPA Act and capped by the 2.015% upper limit on customer bill impacts found in Section 1-75(c)(2)(E) of the IPA Act. The cap on the available budget for each utility is based on the utility's most recent load forecast.

From 2009 through 2012, the IPA's annual electricity procurement plans included the purchase of renewable energy resources in the form of renewable energy credits ("RECs") sufficient to meet the Renewable Portfolio Standard ("RPS") requirements applicable to the eligible retail customer load of ComEd and Ameren Illinois. For the 2013 and 2014 Plans, given the significant percentage of load that had shifted to ARES through municipal aggregation, and the existing financial commitments of the LTPPAs, the IPA and the Commission determined that potential renewable energy resource procurements were limited by the potential for curtailment of existing contracts due to the rate cap on the Renewable Resources Budgets. As a result, general REC procurements (i.e., procurements intended to meet the overall renewable resource targets present in Section 1-75(c)(1) of the IPA Act) were not held for the 2013-2014 or 2014-2015 delivery years.

The advent of a carve-out for photovoltaic resources and the return of load to the utilities made renewable resource procurement once again possible, and in 2015 the IPA procured Solar Renewable Energy Credits ("SRECs") in a spring procurement event (to meet the photovoltaic procurement sub-target found in the Act), and additionally procured RECs from Distributed Generation ("DG RECs") in the fall of 2015 using only previously collected Hourly ACP funds. In 2016 the IPA procured SRECs for Ameren Illinois and ComEd, and (for the first time) RECs (including, specifically, wind RECs and SRECs to meet those sub-targets in the Act) for MidAmerican in a spring procurement event and DG RECs for all three utilities in a June 2016 procurement event.[182]

Consistent with past years, the 2017 Plan calls for REC procurements to meet the RPS targets and technology-specific sub-targets found in Section 1-75(c)(1) of the IPA Act for Ameren Illinois, ComEd, and MidAmerican, with the budgets for those procurements capped by the operation of Section 1-75(c)(2)(E)'s rate impact cap.

MidAmerican's involvement starting with the 2016 Plan raised questions about how to calculate the renewable resource target appropriate to it. Specifically, as a multi-jurisdictional utility participating in the IPA's procurement planning process to meet a portion of its load requirements, MidAmerican's participation raised a previously unaddressed question as to whether renewable energy resources procurement targets should be calculated for <u>all</u> of its eligible retail customer load, or <u>only</u> for <u>that portion</u> of MidAmerican's eligible retail customer load for which the utility specifically requests procurement. Section 1-75(c)(1) of the IPA Act references procurement percentages applicable to "each utility's total supply to serve the load of eligible retail customers, as defined in Section 16-111.5(a) of the Public Utilities Act."[183] While Section 16-111.5(a) defines "eligible retail customer" by customer status that would appear to include MidAmerican's entire eligible retail customer load, this same section also expressly contemplates that MidAmerican may seek procurement for only "a portion of its eligible Illinois retail customers in accordance with the applicable provisions set forth in this Section and Section 1-75 of the Illinois Power Agency Act."[184] In approving the

[182] In 2015 and 2016, the IPA also conducted a series of procurements of SRECs from new photovoltaic systems in Illinois under the separate Supplemental Photovoltaic Procurement Plan ("SPV Plan") pursuant to Section 1-56(i) of the IPA Act; those procurements involved contracts between suppliers and the Agency (rather than with the utilities) using funds from the RERF and were approved through a process separate from the IPA's annual electricity procurement planning process, and thus the resulting RECs from those contracts are not used to meet the renewable energy resource procurement targets discussed herein.
[183] 20 ILCS 3855/1-75(c)(1) (emphasis added).
[184] 220 ILCS 5/16-111.5(a).

2016 Plan, the Commission determined that the renewable resources targets for MidAmerican should only relate to that portion of the "total supply" procured for MidAmerican's jurisdictional eligible retail customers that was included in the 2016 Procurement Plan pursuant to Section 16.111.5 of the PUA and Section 1-75(c) of the IPA Act."[185] The 2017 Plan's procurement targets for MidAmerican thus reflect the Commission's determination made in approving the 2016 Plan.

Section 1-75(c)(1) of the IPA Act requires the procurement of at least a minimum percentage of "each utility's total supply to serve the load of eligible retail customers" from "cost-effective renewable energy resources." Under that provision, specified target percentages of renewable energy resources are required to be procured for each participating utility.[186] The overall renewable energy resources obligation for the utilities in the 2017-2018 delivery year is 13% of the total supply to meet the load of eligible retail customers by June 1, 2017.[187] This obligation increases by at least 1.5% each year thereafter to at least 25% by June 1, 2025.[188] The IPA Act also sets sub-targets for specific resource generating technology types: 75% of the resources procurement shall be generated by wind, 6% for photovoltaics ("PV"), and 1% must come from distributed generation ("DG") which can be used to meet the PV and wind requirements. [189]

The obligation of each electric utility—i.e., the amount of renewable energy resources that have to be procured to meet these statutory minimums—"shall be measured as a percentage of the actual amount of electricity (megawatt-hours) supplied by the electric utility to eligible retail customers in the planning year ending immediately prior to the procurement."[190] This concept can be confusing, as it creates a lag in how the migration of load to or from the ARES manifests itself in changes to renewable energy resource procurement targets. For instance, if a procurement of RECs is scheduled to take place in Spring 2017 for delivery in the 2017-2018 delivery year, the most recently completed year (i.e., the year "ending immediately prior to the procurement") is the 2015-2016 delivery year, as the 2016-2017 delivery year would not have ended prior to the procurement. As a result, customer switching taking place in the fall of 2016 may not manifest itself in significant changes to renewable energy procurement targets until procurements take place in the spring of 2018 for the 2018-2019 delivery year. However, that switching will be reflected in the actual 2016-2017 delivery year load.[191]

The spending cap on the available Renewable Resources Budget ("RRB") is defined as follows:

> The amount of renewable energy resources procured pursuant to the procurement plan for any single year shall be reduced by an amount necessary to limit the estimated average net increase due to the cost of these resources included in the amounts paid by eligible retail customers in connection with electric service to no more than the greater of 2.015% of the amount paid per kilowatt-hour by those customers during the year ending May 31, 2007 or the incremental amount per kilowatt-hour paid for these resources in 2011.[192]

As explained in Section 2.5.1, these values are now fixed; the greater of the two is the 2007 calculation, which constitutes 0.18054 ¢/kWh for Ameren Illinois, 0.18917 ¢/kWh for ComEd, and 0.12415 ¢/kWh for MidAmerican. When these values are multiplied against a utility's forecast eligible retail customer load, it

185 Docket No. 15-0541, Final Order dated December 16, 2015 at 133-134.

186 Renewable energy resources are defined as: "energy and its associated renewable energy credit or renewable energy credits from wind, solar thermal energy, photovoltaic cells and panels, biodiesel, anaerobic digestion, crops and untreated and unadulterated organic waste biomass, tree waste, hydropower that does not involve new construction or significant expansion of hydropower dams, and other alternative sources of environmentally preferable energy. For purposes of [the IPA Act], landfill gas produced in the State is considered a renewable energy resource." 20 ILCS 3855/1-10.

187 20 ILCS 3855/1-75(c)(1).

188 Id.

189 Id.

190 20 ILCS 3855/1-75(c)(2).

191 These quantities are updated with each Plan's load forecast and will change as those forecasts are updated. The updated quantities reflect the impact of revising the load forecast to account for switching due to municipal aggregation which impacted ComEd and to a less significant extent Ameren Illinois.

192 20 ILCS 3855/1-75(c)(2)(E).

creates a budget amount referred to as that utility's "Renewable Resources Budget," which constitutes the maximum that may be spent on renewable resource procurement in a given year under Section 1-75(c)(1) of the IPA Act (additional money may be spent from the renewable energy resources fund for from alternative compliance payments paid by hourly rate customers).

The estimated renewable resource volumes and dollar budgets available for use by each utility and the assumptions that provide the basis for these estimates reflect the utilities' base load forecasts as described in Chapter 3 and adopted by the Commission (and if the Commission were to adopt a different load forecast, then the renewable resource target volumes and budgets would have to be revised accordingly). With each procurement plan, new utility load forecasts are provided to the IPA in July and subsequently updated as necessary the following March to incorporate new data (particularly eligible retail customer switching rates) into the REC procurement targets. Therefore the renewable resource procurement target and related budget estimates presented in future plans could differ significantly from what is presented in this Plan.

In recent years, procurements for Ameren Illinois and ComEd have generally met or exceeded their overall RECs procurement targets. However, some years since 2012 have seen procurements fall short of technology-specific sub-targets. In the 2012 Plan, the IPA included a one-year REC procurement to procure the minimum unbundled RECs required to meet the solar photovoltaic and wind sub-targets (in addition to RECs separately procured through the legislatively mandated 2012 "rate stability" procurements). Due to the volume of long-term (20 year) bundled REC and energy contracts procured in 2010, and declining eligible retail customer load, there were no procurements of renewable resources proposed (or subsequently conducted) in the 2013 or 2014 Plans.

For the 2015–2016 delivery year (2015 Plan), resources under contract from prior IPA procurements for Ameren Illinois and ComEd were sufficient to meet overall RECs targets, but insufficient to meet the law's solar PV requirements. As a result, the IPA proposed and the Commission approved a one-year SREC procurement for ComEd and Ameren Illinois to meet those shortfalls. That SREC procurement was held in the spring of 2015. An additional procurement of DG RECs was held in the fall of 2015 for both ComEd and Ameren Illinois. The 2016 Plan, based on the utility load forecasts as of July 15, 2015 and taking into account MidAmerican's initial year of participation in the IPA procurements, included a spring procurement event for general RECs (MidAmerican only), wind (MidAmerican only), and solar RECs (all utilities) using the utilities' Renewable Resources Budget and a June procurement for distributed generation RECs using hourly ACP funds for Ameren Illinois and ComEd and using the Renewable Resources Budget for MidAmerican.

Turning to the current plan for the 2017-2018 delivery year, existing resources under contract for Ameren Illinois, ComEd and MidAmerican are not sufficient to meet the utilities' renewable resource procurement targets. More specifically, the Ameren Illinois' 2017-2018 targets for overall RECs and wind RECs have been exceeded through prior REC procurements (specifically, the LTPPAs), however Ameren Illinois is short of its PV and DG REC sub-targets. ComEd and MidAmerican are both short of their overall RECs target as well as their wind, solar and DG RECs sub-targets.

To achieve statutory compliance, the IPA recommends Spring 2017 procurements of RECs to meet the ComEd and MidAmerican overall REC targets, and to meet each utility's unmet technology-specific sub-targets (solar PV for all three utilities, wind for ComEd and MidAmerican) for the 2017-2018 delivery year. The quantities to be procured will be based upon the "Remaining Targets" as calculated from the updated March 2017 load forecasts and will be limited to the funds available in the Renewable Resources Budget as reported at that time. As described elsewhere in the Plan, should consensus on the March 2017 load forecasts be needed and not be reached, the quantities of RECs to be procured for the 2017-2018 delivery year will be based upon the "Remaining Target" rows of Table 8-1, Table 8-2, and Table 8-3 for that delivery year found in the Plan.

As discussed above, Section 1-75(c) of the IPA Act also requires the utilities to acquire RECs from distributed generation ("DG") devices amounting to at least 1% of each utility's total RECs target. The Fall 2015 and Summer 2016 DG RECs procurements each experienced very limited participation—there was only one winning bidder in each of those procurements—leaving the targets unmet and raising questions about how to improve the procurement process and facilitate increased participation. For the 2017 Plan, the IPA proposes to schedule at least one DG procurement in 2017 in order to meet the utilities' remaining 2017-2018 delivery year DG REC targets; details related to the structure of the DG procurements are discussed in Section 8.4. Due to the challenges with the prior DG procurements, the IPA is proposing a number of refinements to the 2017 DG procurement in Section 8.4 below.

Under the law, procurements of DG renewable energy resources require contracts of at least 5 years.[193] However, due to the application of the Section 1-75(c)(2)(E) rate impact cap and the potential for continued volatility in the available Renewable Resources Budget caused by customer switching (a risk which could still manifest itself in the potential curtailment of the existing Ameren Illinois and ComEd LTPPAs from 2010), any new long-term obligations entered into using the Renewable Resources Budget would be subject to a high risk of curtailment, a situation which the Agency and Commission have both recognized in rejecting long-term contract proposals from stakeholders in prior years.[194] Therefore, as described further below, the IPA proposes that the DG procurements (for which 5 year contracts are the statutorily mandated minimum length) for ComEd and Ameren Illinois utilized the already-collected balances of alternative compliance payments paid by hourly rate customers; because the MidAmerican service territory does not feature similar load migration risks and because MidAmerican is not a party to the LTPPAs, for MidAmerican, DG contracts will be entered into using the Renewable Resources Budget.

Further, consistent with prior years, the IPA once again does not recommend use of the Renewable Resources Budget for Ameren Illinois or ComEd for renewable energy resource contracts of more than 1 year in length or extending beyond the 2017-2018 delivery year for this Plan. Even if the IPA believes that curtailments are unlikely for the upcoming delivery years, past experience shows that customer switching and load migration—and consequent reduction in available Renewable Resources Budget funds—can happen suddenly and significantly in Illinois, given the opportunity for load shifting in large chunks due to municipal aggregation. With this risk looming, entering into additional contracts featuring obligations beyond the immediate delivery year using the Renewable Resources Budget would be imprudent and unwise, and could result in large and economically inefficient risk premiums in any bids offered by parties understandably concerned about future year curtailments. For Ameren Illinois and ComEd, this may unfortunately limit the use of Renewable Resources Budget funds to meeting the technical requirements of the utilities' RPS mandates rather than achieving broader policy goals such as fostering the development of new renewable generation in Illinois (as might be accomplished through longer-term contracts). However, absent legislative changes to the IPA Act and the PUA, and given the resources currently under contract and continued load volatility, this dynamic will likely continue to limit to what the IPA can propose for use of the Renewable Resources Budget in future years, although the IPA will continue to monitor the operation of this dynamic and analyze it in developing future procurement plans.

The IPA notes that Section 1-56(i) of the IPA Act required the development of an SPV procurement plan for the procurement of RECs from photovoltaic systems using up to $30 million from the RERF. The IPA's Supplemental PV Plan was filed with the Commission in October 2014 and approved in January 2015. The SPV procurements called for in the Supplemental PV Plan were held in June 2015 (using a budget of $5 million), November 2015 ($10 million), and March 2016. ($15 million) There were seven winning bidders to provide 37,082 SRECs in the June 2015 SPV procurement; 11 winning bidders to provide 70,096 SRECS in the November SPV procurement; and eight winning bidders to supply 91,770 SRECs in the March 2016 SPV procurement. These SRECs were procured under five-year contracts from "new" (i.e., energized on or after the date of approval of the Supplemental PV Plan) solar PV DG systems of up to 2 MW in size. As these SRECs

[193] 20 ILCS 3855/1-75(c)(1)

[194] In prior years, both the Agency and the Commission have recognized these risks in rejecting intervenor proposals calling for the Agency to enter into long-term contracts using the Renewable Resources Budget; notably, those proposals called for any new contracts to be curtailed prior to curtailment applying to the existing LTPPAs, further heightening the risks associated with new long-term obligations.

are being purchased by the Agency out of the Renewable Energy Resources Fund and not by the utilities, the SRECs procured under the Supplemental Photovoltaic Plan do not count towards the utilities' statutory targets.

8.1 Utility Renewable Resource Supply and Procurement

8.1.1 Ameren Illinois

As shown in Table 8-1, Ameren Illinois' existing renewable resource contracts alone are sufficient to meet its total renewables targets for the 2017-2018 delivery year. Ameren Illinois is projected to fall short of meeting its RPS requirements in the 2018-2019 delivery year by 37%. In the 2019-2020, 2020-2021, and 2021-2022 delivery years, the shortfall for total renewables is projected to reach 42%, 47% and 51%, respectively.

Table 8-1 also shows the targets and purchasing requirements for Ameren Illinois to meet the goals set by the IPA Act for wind, photovoltaics, and distributed generation based on the currently established fractions of the total renewables requirement.[195] Ameren Illinois is projected to exceed wind sub-target for the 2017-2018 delivery year. Ameren Illinois is projected to fall short of the wind sub-target by 17%, 23%, 30%, and 36% in the 2018-2019, 2019-2020, 2020-2021, and 2021-2022 delivery years, respectively. Ameren Illinois is projected to fall short of its PV and DG goals in each delivery year.

Additionally, Ameren Illinois is projected to have Renewable Resources Budget funds[196] available to purchase renewables over the 5-year forecast period (Table 8-4).

Table 8-1: Ameren Illinois Existing RPS Contracts vs. Forecast RPS Requirements[197]

Delivery Year	Quantities	Total Renewables	Wind	Photo-voltaics	Distributed Generation
2017-2018	Target (MWh)	842,877	632,158	50,573	8,429
	Purchased (MWh)	855,785	848,338	7,429	1,389
	Remaining Target (MWh)	0	0	43,144	7,040
2018-2019	Target (MWh)	955,154	716,365	57,309	9,552
	Purchased (MWh)	601,389	596,571	4,800	1,389
	Remaining Target (MWh)	353,765	119,794	52,509	8,163
2019-2020	Target (MWh)	1,039,309	779,482	62,359	10,393
	Purchased (MWh)	601,389	596,571	4,800	1,389
	Remaining Target (MWh)	437,920	182,911	57,559	9,004
2020-2021	Target (MWh)	1,139,425	854,569	68,366	11,394
	Purchased (MWh)	600,435	596,571	3,864	435
	Remaining Target (MWh)	538,990	257,998	64,502	10,959
2021-2022	Target (MWh)	1,237,782	928,336	74,267	12,378
	Purchased (MWh)	600,000	596,571	3,429	0
	Remaining Target (MWh)	637,782	331,765	70,838	12,378

[195] 20 ILCS 3855/1-75(c)(1).
[196] Available Renewable Resources Budget funds for the upcoming year is a function of, among other things, forecasted eligible retail customer load which can be affected by customer switching.
[197] Volumes are based on the July 2016 expected load forecast. The March 2017 load forecast will update the 2017-2018 volumes and the quantity of DG RECs purchased in the Fall 2015 and Summer 2016 procurements, and future years' actual procurement targets will be based off of those future years' load forecasts.

8.1.2 ComEd

Table 8-2 shows ComEd's current RPS contracts relative to its renewables requirements and includes consideration of ComEd's statutory targets established for total renewable energy resources as well as for wind, photovoltaics, and distributed generation over the five-year forecast horizon. ComEd's forecast indicates that for the 2017-2018 delivery year, total renewables are 775,523 RECs short of the target. In subsequent delivery years, ComEd is forecasted to fall short of its total renewables target by 56% in 2018-2019, 64% in 2019-2020, 67% in 2020-2021, and 70% in 2021-2022. ComEd is also forecasted to fall short of the photovoltaic, wind and distributed generation targets in each of the five delivery years considered in this Plan.

As with Ameren Illinois, ComEd is also projected to have Renewable Resources Budget funds with which to purchase renewables (Table 8-5).

Table 8-2: ComEd Existing RPS Contracts[198] vs. Forecast RPS Requirements[199]

Delivery Year	Quantities	Total Renewables	Wind[200]	Photo-voltaics[201]	Distributed Generation[202]
2017-2018	Target (MWh)	2,311,700	1,733,775	138,702	23,117
	Purchased (MWh)	1,536,177	1,233,860	30,844	2,979
	Remaining Target (MWh)	775,523	499,915	107,858	20,138
2018-2019	Target (MWh)	2,893,330	2,169,998	173,600	28,933
	Purchased (MWh)	1,264,704	1,233,860	30,844	2,979
	Remaining Target (MWh)	1,628,626	936,138	142,756	25,954
2019-2020	Target (MWh)	3,557,835	2,668,376	213,470	35,578
	Purchased (MWh)	1,264,704	1,233,860	30,844	2,979
	Remaining Target (MWh)	2,293,131	1,434,516	182,626	32,599
2020-2021	Target (MWh)	3,905,042	2,928,782	234,303	39,050
	Purchased (MWh)	1,262,768	1,233,838	28,930	1,043
	Remaining Target (MWh)	2,642,274	1,694,944	205,373	38,007
2021-2022	Target (MWh)	4,260,265	3,195,199	255,616	42,603
	Purchased (MWh)	1,261,725	1,233,838	27,887	0
	Remaining Target (MWh)	2,998,540	1,961,361	227,729	42,603

[198] Delivery year 2017-2018 is the last year for the rate stabilization procurement purchases to be delivered, which amounts to 271,473 RECs for ComEd.

[199] Volumes are based on the July 2016 expected load forecast. The March 2017 load forecast will update the 2017-2018 volumes and the quantity of DG RECs purchased in the Fall 2015 and Summer 2016 procurements, and future years' actual procurement targets will be based off of those future years' load forecasts.

[200] Wind RPS requirement is 75% of the annual RPS requirement. See 20 ILCS 3855/1-75(c)(1).

[201] PV RPS requirement is 6% of the annual RPS requirement. See 20 ILCS 3855/1-75(c)(1).

[202] Distributed Generation RPS requirement is 1% of the annual RPS requirement. See 20 ILCS 3855/1-75(c)(1).

8.1.3 MidAmerican

Table 8-3 shows the forecast of the statutory targets for MidAmerican's procurement of total renewable energy resources, wind, photovoltaics, and distributed generation over the five-year forecast horizon, reflecting the methodology approved by the Commission in Docket No. 15-0541.[203] Prior to procurements made to meet MidAmerican's 2016-2017 delivery year targets, MidAmerican did not have any renewable resource contracts extending into the five-year delivery period. In the IPA's May 4, 2016 procurement event, RECs were procured for MidAmerican's target requirements via one-year contracts for the 2016-2017 delivery year.

Table 8-3: MidAmerican Existing RPS Contracts vs. Forecast RPS Requirements

Delivery Year	Quantities	Total Renewables	Wind[204]	Photo-voltaics[205]	Distributed Generation[206]
2017-2018	Target (MWh)	65,547	49,160	3,933	655
	Purchased (MWh)	0	0	0	131
	Remaining Target (MWh)	65,547	49,160	3,933	524
2018-2019	Target (MWh)	78,179	58,634	4,691	782
	Purchased (MWh)	0	0	0	131
	Remaining Target (MWh)	78,179	58,634	4,691	651
2019-2020	Target (MWh)	106,245	79,684	6,375	1,062
	Purchased (MWh)	0	0	0	131
	Remaining Target (MWh)	106,245	79,684	6,375	931
2020-2021	Target (MWh)	127,032	95,274	7,622	1,270
	Purchased (MWh)	0	0	0	131
	Remaining Target (MWh)	127,032	95,274	7,622	1,139
2021-2022	Target (MWh)	113,408	85,056	6,804	1,134
	Purchased (MWh)	0	0	0	0
	Remaining Target (MWh)	113,408	85,056	6,804	1,134

8.2 Available Renewable Resources Budget and LTPPA Curtailment

In 2010, pursuant to an IPA procurement, ComEd and Ameren Illinois entered into long-term (20-year) contracts for renewable energy resources ("LTPPAs") from certain wind and photovoltaic generating facilities. In past proceedings, the IPA has sought express authorization for those contracts to be "curtailed" (a mandated reduction in the amount which need be purchased under the contract) should the payments required under the contract exceed the expected Renewable Resources Budget. A curtailment of these contracts can be triggered by a significant number of customers switching to alternative suppliers and consequently load shifting away from the utilities, thus reducing the available budget below the amount necessary to cover all existing renewable energy resource contractual obligations.

8.2.1 Impact of Budget Cap

Section 1-75(c)(2) of the IPA Act requires the IPA to reduce the amount of renewable energy resources to be procured for any particular year in order to keep the "estimated" net increase in charges to eligible retail customers below the statutory 2.015% rate impact cap. In the past four Plans, in an effort to keep the cost of

[203] For this Plan, consistent with Ameren Illinois and ComEd, MidAmerican electricity usage for calculating its RPS targets and budgets are usage volumes as measured or forecasted at the customers' meters (as opposed to wholesale volumes used for MidAmerican in the 2016 Procurement Plan, which included T&D losses).
[204] Wind RPS requirement is 75% of the annual RPS requirement. See 20 ILCS 3855/1-75(c)(1).
[205] PV RPS requirement is 6% of the annual RPS requirement. See 20 ILCS 3855/1-75(c)(1).
[206] Distributed Generation RPS requirement is 1% of the annual RPS requirement. See 20 ILCS 3855/1-75(c)(1).

renewable energy resources below the statutory rate impact cap, the Commission pre-approved the possible curtailment of the LTPPAs based on the information contained in that subsequent March's updated load forecasts. Curtailment was required of ComEd's LTPPAs in 2013–2014 and 2014-2015, but has not yet been required for the Ameren Illinois contracts. Curtailments were not required in the 2015-2016 and 2016-2017 delivery years and, based on the load forecasts supplied by the utilities, are not currently anticipated over the five-year forecast horizon of the 2017 Procurement Plan; however, because curtailment is still possible (and indeed would occur under the Ameren Illinois low load forecast), the Agency is once again requesting pre-approval of pro rata curtailment of the LTPPAs from the Commission should the updated load forecasts demonstrate that curtailment is necessary.

For the 2017-2018 delivery year, the Renewable Resources Budgets for Ameren Illinois and ComEd are expected to exceed the contractual cost for RECs already procured in each delivery year. Therefore, both Ameren Illinois (Table 8-4) and ComEd (Table 8-5) are forecast to have sufficient funds available in each of the five delivery years covered by this plan. MidAmerican likewise has sufficient funds available in each delivery years.

Table 8-4: Forecast Available Renewable Resources Budget Funds and Forecast Reductions (Curtailments) of LTPPAs, Ameren Illinois

Delivery Year	Contractual REC Cost ($)	Delivery Year RPS Budget ($)	Available RPS Funds ($)	LTPPA Quantity Reduction (%)
2017-2018	9,412,155	11,727,302	2,315,147	0
2018-2019	8,000,000	11,754,961	3,754,961	0
2019-2020	7,999,000	11,761,534	3,762,534	0
2020-2021	7,753,000	11,758,174	4,005,174	0
2021-2022	5,554,000	11,775,895	6,221,895	0

Table 8-5: Forecast Available Renewable Resources Budget Funds and Forecast Reductions (Curtailments) of LTPPAs, ComEd

Delivery Year	Contractual REC Cost ($)	Delivery Year RPS Budget ($)	Available RPS Funds ($)	LTPPA Quantity Reduction (%)
2017-2018	23,804,638	42,064,725	18,260,087	0
2018-2019	23,446,480	42,212,391	18,765,911	0
2019-2020	23,576,285	42,416,545	18,840,260	0
2020-2021	23,188,923	42,359,368	19,170,445	0
2021-2022	18,683,296	42,350,704	23,667,408	0

The contracted REC costs for the 2017-2018 delivery year for Ameren Illinois and ComEd are respectively 80% and 57% of the current estimates of their respective 2017-2018 RPS budget caps. Those budgets depend directly on eligible retail customer load, so it appears that as long as Ameren Illinois's March 2017 forecast for 2017-2018 load is close to 80% of its July 2016 forecast value, and as long as ComEd's March 2017 forecast for 2017-2018 load is close to 57% of its July 2016 forecast value, neither utility will have to curtail its LTPPAs. Under the two utilities' low load forecast scenarios, ComEd would not have to curtail its LTPPAs; however, Ameren Illinois low load forecasts that the Renewable Resources Budget would be exceeded and a partial curtailment of LTPPAs would be needed.

While it appears unlikely that curtailment of the LTPPAs would be required in the 2017-2018 delivery year, the IPA still recommends that a final determination be based upon the March 2017 load forecasts. In the event that curtailments are required, the IPA recommends that the methodology adopted in the ICC's Order on Rehearing of the 2014 Procurement Plan be employed for the calculation of REC prices for curtailed RECs (including the use of Annual Contract Values).[207] While it is again unlikely that curtailments will be required, because hourly ACP funds are proposed for procurement of DG RECs, the IPA proposes to address a potential curtailment through continuing its prior offer to purchase curtailed RECs at the imputed REC prices from the 2010 contracts using the Renewable Energy Resources Fund should hourly ACP funds leftover after the DG procurement be insufficient to purchase curtailed RECs.

Table 8-6 shows the Renewable Resources Budget available for MidAmerican.[208] As discussed above, the Commission determined that the renewable resource targets present in Section 1-75(c)(1) apply only to the incremental load for which the IPA conducts its procurement, and that the calculation of MidAmerican's Renewable Resources Budget funds should reflect MidAmerican's comments on the IPA's 2016 Plan, which also call for MidAmerican's Renewable Resources Budget to be based on incremental load (shown in the table below).

Table 8-6: Forecast Available Renewable Resources Budget Funds, MidAmerican

Delivery Year	Contractual REC Cost ($)	Delivery Year RPS Budget ($)	Available RPS Funds ($)
2017-2018	24,877	824,398	799,521
2018-2019	24,877	901,200	876,323
2019-2020	24,877	741,029	716,152
2020-2021	24,877	721,276	696,399
2021-2022	0	746,534	746,534

8.3 Use of Hourly Alternative Compliance Payments Held by the Utilities

Ameren Illinois and ComEd also collect Alternative Compliance Payments ("ACPs") on behalf of customers taking hourly service from the utility.[209] Unlike the ACP funds paid by ARES into the RERF, which are held and administered by the IPA, utility hourly customer ACP funds are held by the utilities.[210] As required by the IPA Act, each utility has disclosed the amount of hourly customer ACP funds being held as of May 31, 2016: for Ameren Illinois, the balance is $12,665,469 ($12,348.925 after adjusting for DG REC contracts signed after May 31, 2016); for ComEd, the balance is $27,467,027 ($26,818,750 after adjusting for DG REC contracts signed after May 31, 2016).

The IPA Act requires that ACP funds from utility hourly customers be used to "increase [the utility's] spending on the purchase of renewable energy resources to be procured by the electric utility for the next plan year by an amount equal to the amounts collected by the utility under the alternative compliance payment rate or rates in the prior year ending May 31."[211] Starting with the 2013-2014 delivery year, the Commission approved the use of hourly ACP funds to purchase RECs from any curtailed LTPPAs. In the unlikely event of future curtailments, the IPA recommends a continuation of that policy, with the caveat that these purchases would be secondary to the already contractually committed use of the hourly ACP funds for the DG

[207] In its Order on Rehearing in approving the 2014 Plan, the Commission requested that the allocation method used "will be reviewed again and determined in the IPA Procurement Plan case for," in that case, "the 2015-2016 year." (Docket No. 13-0546, Order on Rehearing dated June 17, 2014 at 56). Due to the low probability of needing to curtail the LTPPA contracts in the upcoming delivery year, the IPA has determined that the curtailment methodology does not need to be updated at this time and consideration of this issue deferred to a future year where it is more relevant.

[208] Because the Commission determined in Docket No. 15-0541 that the RPS targets found in Section 1-75(c) of the IPA Act only apply to the portion of MidAmerican's load procured by the IPA, this budget is based on a prorated portion of MidAmerican's total forecast load. For the 2017-2018 Delivery Year, the size of the MidAmerican load served by the IPA procurement process is forecast to be 697,236 MWh (out of MidAmerican's total Illinois forecast load of 2,004,708 MWh).

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

[210] See id.

[211] Id.

procurement as discussed below. The purchase of curtailed RECs from the LTPPAs would take precedence over new DG procurements undertaken in 2017.

Utilizing the already collected, and otherwise unspent, hourly ACP funds to allow Ameren Illinois and ComEd to meet their DG sub-targets also appears to be the best way to manage risks associated with longer-term contracts. As the IPA Act requires that contracts for DG resources must be "no less than 5 years" in length,[212] entering into 5-year contracts using existing ACP funds already collected from hourly customers eliminates the load migration risk present with the Renewable Resources Budget (from which long-term contracts have been subject to curtailments in the past) while ensuring that there are no impacts on customer rates. Based on this same logic, this approach was proposed by the IPA and approved by the Commission in both the 2015 and 2016 Procurement Plans.

Although distributed generation systems were eligible to participate in the IPA's prior renewable energy resource procurements, the Fall 2015 procurement specifically targeting DG resources was the first of its kind conducted by the IPA. The Fall 2015 procurement was followed by a subsequent DG RECs procurement in June 2016. As previously discussed, the DG procurements held for the utilities in the fall of 2015 and the summer of 2016 featured low participation and fell short of meeting their statutory DG sub-targets.

8.4 Distributed Generation Procurement

The IPA's model for the DG procurement described in the 2015 Plan was the starting point for the DG procurement also proposed and approved in the 2016 Plan. That model is once again updated for this Plan in order to try to achieve procurement results closer to the target volumes.

The IPA recognizes that given the limited amount of distributed generation currently in Illinois, the success of this procurement hinges on the ability of the Illinois DG market both to self-organize and, given the fact that previous-winning systems have 5 year contracts and other systems may already have REC contracts (such as those from the SPV procurement), to continue to grow. To encourage increased participation, the Agency will allow bids to contain DG systems of all qualifying sizes and resource types. Consistent with the law defining a distributed generation device, systems must be no larger than 2,000 kW. The confidential benchmarks used by the Procurement Administrator to evaluate bids may depend on system size, technology, and other factors. Consistent with the approach taken in the SPV procurement (which also featured the requirement that 50% of RECs come from systems of below 25 kW in size) and with past DG procurements, bids that meet or beat the benchmarks will be selected on the basis of price, and on the basis of trying to achieve a 50-50 balance of RECs procured from each of the two categories of systems, namely systems below 25 kW and systems of 25-2,000 kW in size.

Contracts will provide for each system under the contract having a five full years (60 months) of REC deliveries beginning with each system's first delivery of RECs, and allowing for development time between the procurement event and the first REC delivery to facilitate the construction of new systems.

The IPA has held two DG procurements to date. Neither procurement came close to achieving its target REC procurement volumes and each had only one winning bidder. In both procurements, additional entities beyond the winning bidder took part to varying degrees in every step of the bidding process, but challenges (including for example, assembling bids that would meet the requirements of the procurement and obtaining necessary letters of credit by the bid date) limited ultimate participation. As discussed below the IPA is proposing a number of changes to the DG procurement structure utilized for 2017 with the hope that these changes will increase the volume bid and procured. While the IPA is hopeful that these changes can increase participation and help facilitate satisfaction of the Section 1-75I(1) DG procurement targets, the Agency recognizes that there may be provisions of the law (such as the 1 MW minimum bid size requirement) that could prove to be insurmountable barriers to stronger participation absent legislative change.

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

Section 16-111.5(o) of the PUA requires that the ICC "hold an informal hearing for the purpose of receiving comments on the prior year's procurement process and any recommendations for change." On June 30, 2016, the Commission's independent Procurement Monitor, Boston Pacific, provided comments[213] to the Commission as part of this process that included a summary of possible changes to the DG procurement process that could improve participation. The revisions proposed in the Plan reflect the Procurement Monitor's suggestions as well as additional proposals and refinements proposed by the IPA. In addition, the IPA specifically solicited feedback on the draft Plan regarding its DG procurement proposal and received many helpful comments. Many of those comments generally supported the IPA's proposed changes to the DG procurement design, and aspects of those and other comments have been incorporated into the DG procurement proposal.

Available funding, however, has not been a constraint to the DG procurement process and therefore the IPA's DG renewable resource procurements will continue to use hourly ACP funds for Ameren Illinois and ComEd, and use the Renewable Resources Budget for MidAmerican (including forecasts of the available budget over the life of the contracts). Hourly ACP funds that have been collected as of December 31, 2016 and not allocated to the purchase of either DG RECs from the previous five-year DG procurement contracts or curtailed RECs for the 2017-2018 delivery year will be used for Ameren Illinois and ComEd in any procurement conducted prior to June 30, 2017. For any procurement conducted after July 1, 2017, the same approach will be used, but the balance of Hourly ACP funds will be adjusted to the May 31, 2017 balance and, for the second procurement event, any DG contract commitments already entered into in 2017. The IPA will procure DG RECs until funds are fully allocated or the utilities' DG goals are met, whichever comes first. The products to be procured are RECs from DG systems that are interconnected with Ameren Illinois, ComEd, MidAmerican (Illinois service territory only), Mount Carmel, a municipal utility in Illinois, or a rural electric cooperative in Illinois as required by Illinois law. DG systems need not be in the service territory of the utility purchasing the RECs.

8.4.1 Procurement Process

For this Plan, the Agency's approach to procuring DG RECs consists of a two procurement events in a competitive bid process consistent with the requirements of Section 16-111.5 of the PUA and Section 1-75(c) of the IPA Act as was conducted in the 2015 and 2016 procurements. Timing of the procurement events will be determined at a later date based upon if the IPA determines that it will be conducting an April, 2017 contingency procurement under the Supplemental Photovoltaic Plan, and other factors.

Given the requirement in Section 1-75(c) that "the Agency shall solicit the use of third-party organizations to aggregate distributed renewable energy into groups of no less than one megawatt in installed capacity," bids must once again be at least one megawatt in size, but may feature DG systems of all qualifying sizes and resource types subject to the size categories and limits discussed above (specifically that a system may not be greater than 2 MW in size, and the underlying generation technology must be "renewable" such that the system meets the requirements of a "distributed renewable energy generation device").[214]

To further encourage participation, for 2017 the IPA also proposes to allow both bids from 1) identified distributed generation systems (consistent with past practice in DG procurements), and 2) for blocks of RECs where systems less than 25 kW in size will be identified at a later date (distinct from prior DG procurements, but with the goal to encourage participation consistent with the successful approach taken by the Agency in its SPV procurement) with the hope that this will allow bidders to use a REC contract won through the DG procurement process as a mechanism to acquire new customers and to develop the new systems necessary to meet DG REC delivery requirements.

For identified systems, the bidder must identify the specific system(s) that will provide the RECs. Evidence regarding the systems may include, but is not limited to, letters of intent, signed contracts, interconnection or net metering applications, local permits, and similar documents. For blocks of RECs, bidders will have nine

[213] See: https://www.icc.illinois.gov/downloads/public/Boston%20Pacific's%20Comments%20June%2030%202016%20Final.pdf.
[214] See 20 ILCS 3855/1-10.

months to identify specific systems using the same standards as for identified systems.[215] To reduce contract administration burdens on the participating utilities (consistent with the law), verification of these newly identified systems will be conducted by the IPA and the IPA will be responsible for transmitting information about newly-identified systems to the applicable utility. Failure to identify systems by the nine month deadline will result in the forfeiture of any bid assurance collateral requirements, with such forfeiture prorated in cases where systems are identified to partially meet the size of the block of RECs.

As referenced above, the IPA Act requires that the bids "aggregate distributed renewable energy into groups of no less than one megawatt in installed capacity." Consistent with this provision, the first block of DG systems bid by each bidder must be at least one megawatt in size and may include systems from each product size category (i.e., less than 25 kW and 25 kW to 2 MW). Each product size category is offered at a single blended price per REC. Subsequent blocks of DG systems must be bid at higher prices and must each be of a single product size category, must each be offered at a single price per REC that is higher than the price of that category in the first block, and must each be at least 100 kW. Bidders may not designate different REC prices for the RECs generated from a single distributed generation system. While block prices may differ, each bidder's resulting REC contract with a purchasing utility will be at a single blended price, encompassing all successful systems which have been assigned to that utility. Further, consistent with the approach adopted by the Commission in Docket No. 15-0541, resulting contracts shall include a single blended price for each product size category (i.e., less than 25 kW and 25 kW to 2 MW).[216] A pre-determined capacity factor for each eligible technology and potentially varying by project size (or type, e.g., fixed or tracking solar systems) will be used to calculate the five year quantity of RECs for each system.

While each of the utilities has separate compliance targets and budgets, winning bids will be assigned to the utilities by the Procurement Administrator considering each utility's budget and implementing the following priorities: 1) to minimize the administrative burden for utilities and bidders by having each bidder have a single contract with a single utility to the extent feasible; 2) to have utilities get their pro-rata share of the RECs; and 3) to have 50% of the RECs for each utility come from systems below 25 kW. The Procurement Administrator may use its discretion in assigning bids (including prorated shares of bids) to each utility to accommodate the fact that the proration of the total volume of selected bids that would be allocated to each utility's procurement target may not be evenly divided due to the size of the winning bids, and/or each utility's available budget.

Each identified system included in a contract awarded in a procurement held prior to May 31, 2017 must begin accumulating metered deliveries of renewable energy (as tracked by GATS or M-RETS) by May 31, 2018—the end of the 2017-2018 delivery year. An identified system included in a contract awarded in a procurement held on or after June 1, 2017 must begin accumulating metered deliveries of renewable energy by November 30, 2018. For systems identified out of a block of RECs, the deadline for the beginning of accumulation of metered deliveries of renewable energy is nine months later than the deadline for systems bid as identified systems in that corresponding procurement event. Should a system not comply with this requirement, the bidder's contract volume will be reduced accordingly by the amount imputed to that system.[217]

8.4.2 Key Contract Terms

Contracts under the DG procurements will be between winning bidders and Ameren Illinois, ComEd, or MidAmerican; the IPA is not a contract party as it is for the procurements of SRECs using the RERF conducted pursuant to the SPV Plan. Contracts will provide payment for RECs generated over five years for each system

[215] For the IPA's Supplemental Photovoltaic procurements, bidders were given six months to identify systems plus an option to request a three month extension. Nearly all bidders requested the three month extension; therefore it appears that nine months is the practical window for bidders to conduct their marketing and sales processes to identify systems.
[216] See Docket No. 15-0541, Final Order dated December 16, 2015 at 144.
[217] Extensions will be granted for limited circumstances such as (but not limited to) demonstrated delays in a utility approving interconnection of a system, or failure for the tracking system to process registration in a timely manner.

included in the contract as well as the necessary time for the identification and/or development of the systems. Utility contracts will not feature payments prior to REC delivery, such as pre-payment at the execution of a contract or when a system becomes energized. The contract may be transferred or assigned by the winning bidder or seller of the contract consistent with the terms specified within each utility's contract. The IPA will endeavor to harmonize the contract language used by each utility, but recognizes that due to the business rules and practices of each utility, it may not be possible to have identical contract language. For each utility, however, a standard contract will be offered.

8.4.3 Credit Requirements and Bidder/Supplier Fees

Procurements conducted under Section 16-111.5 require that the IPA recover the cost of conducting the procurement through bidder fees,[218] and distributed generation procurements likewise require that the Agency "create credit requirements for suppliers of distributed renewable energy."[219] The IPA proposes the following fees and credit requirements.

- All bidders will pay a $500 bid participation fee. This fee is non-refundable. Bidders who participate in other IPA procurements in 2017 will only have to pay the $500 fee one time.
- For 2017, as a way to ensure that potential bidders have the means and intention to develop systems from blocks bid, the IPA will require a $4/REC letter of credit for both identified systems and for blocks of RECs as part of the bidder registration process.[220]
- Bidders who do not win will have their letters of credit returned. For a bidder who only is successful for a portion of their bids, the level of the letter of credit will be reduced on a prorated basis based upon their winning bids.
- Winning bidders will also be assessed a Supplier Fee that reflects the cost of conducting the procurement less the total of the bid participation fees.[221] An estimated Supplier Fee per REC will be announced prior to the opening of bidder registration, and the final Supplier Fee per REC will be announced after bidder registration is completed but prior to the bid due date. Winning bidders will have seven business days after the approval of the procurement results by the Commission to pay the Supplier Fee due to the IPA. Failure to pay the Supplier Fee will result in the forfeiture of the letter of credit and will be considered a breach of the contract that if not corrected would be cause for termination of the contract.
- As systems demonstrate that they have begun accumulation of metered delivery of renewable energy (as described in Section 8.4.1 above) the pro-rated performance assurance level of the letter of credit will be reduced.[222] Failure to begin accumulation of metered delivery of renewable energy from a system by the system's deadline will also result in the IPA drawing on the letter of credit for that pro-rated amount. Likewise, failure to identify systems from blocks of RECs by the nine-month deadline will result in the forfeiture of the associated performance assurance and the IPA will draw on the letter of credit for that pro-rated amount.

[218] 20 ILCS 3855/1-75(h).

[219] 20 ILCS 3855/1-75(c)(1).

[220] Given the continued challenges surrounding the state budget and appropriations for state agencies including the IPA, the Agency will not accept cash as a means for meeting this requirement.

[221] As the DG procurement is held pursuant to the requirements of Section 1-75 of the IPA Act, subsection (h) requires that, "[t]he Agency shall assess fees to each bidder to recover the costs incurred in connection with a competitive procurement process." This is distinct from the Supplemental Photovoltaic Procurement process held pursuant to Section 1-56(i) of the IPA Act, as Section 1-56(i)(9) allowed the IPA to use the Renewable Energy Resources Fund to cover the administrative costs of SPV procurements. The IPA further notes that increasing participation in the DG procurement will lower the per REC supplier fee compared to previous years.

[222] In past years, DG procurements have required that a portion of the performance assurance continue to be held by the utility over the life of the contract, refunded as deliveries are made. Noting that having a deposit held by a contractual counterparty over a 5-year period may inhibit participation from some bidders, and in an effort to encourage increased participation in the DG procurement process, the IPA is instead proposing this simplified and reduced credit requirement.

To encourage increased participation, to lower the barriers for smaller local installers, to reduce administrative burdens on the utility, and in recognition that the greatest risk of non-delivery resides in the inability to successfully develop a DG system (rather than in the system's ability to delivery RECs once energized and interconnected), there will not be credit requirements, including credit requirements with the utilities, other than those described above. Should the IPA draw on the letters of credit for non-performance, the IPA will use those funds collected to lower the supplier fees for future DG procurements. Failure for a system to begin REC deliveries will impact the given utility' achievement of its DG goals under Section 1-75(c) of the IPA Act and the IPA will adjust procurement targets for future DG procurements to reflect those changes.

While this DG procurement structure does not feature an ongoing security requirement with the utility, winning DG systems will not be eligible to sell RECs generated from that system in any other IPA procurement during the delivery period of the contract.[223] Additionally, the IPA will monitor any failure by identified, energized systems to deliver RECs as scheduled during the delivery period for willful noncompliance; should the Agency determine that the Seller has willfully non-complied with a delivery contract (such as, for instance, via selling DG RECs contractually obligated for utility delivery to a third party instead), that determination may impact the Seller's ability to participate in future IPA procurements.

These and other DG REC delivery contract terms and conditions will be developed to be consistent with the contract process and requirements set forth in Section 16-111.5(e) of the PUA.

8.4.4 Aggregators

Unlike with the IPA's SPV Plan, DG procurements made to meet Section 1-75(c) targets using the procurement mechanisms in Section 16-111.5 of the PUA require the aggregation of "distributed renewable energy into groups of no less than one megawatt in installed capacity." This requirement is manifest in the one megawatt bid requirement mentioned above. The IPA will allow for "self-aggregation" from system owners, so long as those bids are at least one megawatt in size. In all cases, the bidder serves as the counterparty with the utility in contracts for the delivery of RECs; in the case of non-system owners (third-party aggregators), the bidder must have ownership over the RECs or the contractual right to transfer or assign RECs to the utility legally.

Given the number of systems required to constitute a full megawatt, meeting a one megawatt threshold may be challenging for aggregators organizing bids of smaller systems. It may be also especially challenging given the relatively small universe of existing DG systems in Illinois. Any participating system owner would both need to 1) have RECs available for sale (i.e., not already under contract) and be willing to transfer available RECs;[224] and 2) have the knowledge and understanding necessary to participate through an aggregator in an IPA procurement event. The addition of the option to bid blocks of RECs in addition to identified systems is intended to be a means to address this challenge. Potential participants may also choose to join together to create a sufficiently-sized bid (with one entity serving as the "bidder" for purposes of the procurement and resulting contractual counterparty).

In developing the DG RFP rules and process, the IPA and Procurement Administrator may also explore additional ways to facilitate joint participation by entities capable of assembling bids, but not necessarily bids of one megawatt in size, with the goal that through joint participation, a sufficiently-sized bid could be

[223] Exceptions may be made, however, for systems with only partial contracts (such as the marginal winning system in a competitive procurement, for which the contract offered may not cover the full output of the system given the application of the procurement budget or procurement targets).

[224] Based on industry feedback, the IPA understands this may be a challenge for the operators of some existing commercial systems who already claim that their energy is sourced from renewables because the sale, transfer, or assignment of the environmental attributes (i.e., the RECs) is inconsistent Federal Trade Commission guidelines. (see http://www.business.ftc.gov/documents/environmental-claims-summary-green-guides for more information). While this factor is unlikely to present a challenge with aggregating smaller residential systems, participation from larger systems may be necessary for a 1 MW threshold to be met.

submitted. Any mechanisms developed would be consistent with the other provisions of this section, and would be developed in a manner mindful of the need to minimize administrative burdens on contracting utilities and the requirements under the prevailing statute.

8.5 Alternative Compliance Payments Held by the IPA in the Renewable Energy Resources Fund

The RERF balance as of September 27, 2016 equals $188,194,026.84, the total amount received in the IPA's RERF attributable to ARES ACP payments less the cost of RECs purchased by the IPA, expenses related to the SPV procurement process, and a permanent $98 million transfer to the Illinois General Revenue Fund pursuant to Public Act 99-0002. The ICC has held on two separate occasions that it does not have jurisdiction over the RERF, and as a result the IPA does not seek approval for procurement using the RERF in this procurement plan (just as it has not in previous years).[225]

Section 1-56(i) of the IPA Act required the IPA to develop a SPV procurement plan to spend up to $30 million on RECs from photovoltaic resources using the RERF. The Agency's SPV procurement plan was approved by the Commission in Docket No. 14-0651. The SPV procurement plan called for at least three procurement events (with the possibility of a fourth procurement event if funding was available). The first procurement event under that plan was held in June 2015 and successfully allocated the full $5 million budget for that event; the second was held in November 2015 and successfully allocated the full $10 million budget for that event; and the third was held in March 2016 and fully allocated the full $15 million budget for that event. While the SPV procurement plan does not direct the IPA to utilize the full RERF balance (which will increase as ARES make future compliance payments), it is an important first step forward in allowing those funds to be used for their intended purpose. The IPA hopes that future legislative changes will add to the ease through which the IPA can use the remaining fund balance to further the RERF's purposes.

[225] See Docket No. 12-0544, Final Order dated December 19, 2012 at 112-114; Docket No. 15-0541, Final Order dated December 16, 2015 at 144.

9 Energy Efficiency

This Chapter of the Procurement Plan sets out recommendations for the consideration and approval of incremental energy efficiency programs under Section 16-111.5B of the Public Utilities Act.[226] As described in Section 2.6 of this Plan, Section 16-111.5B of the Public Utilities Act requires the IPA to include in its Procurement Plan,

> [A]n assessment of opportunities to expand the programs promoting energy efficiency measures that have been offered under plans approved pursuant to Section 8-103 of this Act or to implement additional cost-effective energy efficiency programs or measures.[227]

The IPA bases its recommendations on "an assessment of cost-effective energy efficiency programs or measures that could be included in the procurement plan" submitted to it by the utilities as part of their July 15th load forecasts.[228] This annual assessment provided by the utilities is required to include the "[i]dentification of cost-effective energy efficiency programs or measures that are incremental to those included in energy efficiency and demand-response plans approved by the Commission pursuant to Section 8-103 of this Act,"[229] an "[a]nalysis showing that the new or expanded cost-effective energy efficiency programs or measures would lead to a reduction in the overall cost of electric service,"[230] and an "[a]nalysis of how the cost of procuring additional cost-effective energy efficiency measures compares over the life of the measures to the prevailing cost of comparable supply."[231]

Section 16-111.5B was originally enacted as part of Public Act 97-0616, the Energy Infrastructure and Modernization Act ("EIMA"), in 2011. Its provisions are meant to complement, enhance, and expand the utilities' existing energy efficiency program portfolios required by Section 8-103 of the Public Utilities Act through the inclusion in the IPA's annual procurement plans of "new or expanded . . . incremental" programs that would otherwise not be included in the Section 8-103 portfolios due to the operation of Section 8-103's 2.015% rate impact cap.[232] To identify these "incremental" programs, the utilities are required to "conduct an annual solicitation process for purposes of requesting proposals from third-party vendors" developed "consistent with the manner in which it develops requests for proposals under plans approved pursuant to Section 8-103 of this Act, which considers input from the Agency and interested stakeholders."[233] The results of that RFP process are provided to the IPA as part of each utility's assessment. Under this structure, the IPA then "shall include" in its annual plan "energy efficiency programs and measures it determines are cost-effective"[234] and the Commission "shall approve" those programs and measures "if the Commission determines they fully capture the potential for all achievable cost-effective savings, to the extent practicable, and otherwise satisfy the requirements of Section 8-103" of the PUA.[235]

This section includes discussion related to programs and measures which the IPA recommends for inclusion in the 2017 Plan as well as discussion of other issues related to the operation of Section 16-111.5B, including the status of issues designated for workshop discussion through prior Commission Orders.

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[226] The consideration of these programs has been previously included in Chapter 7 of the Plan. For the 2017 Plan, the IPA is presenting these programs in a separate Chapter to increase the clarity of the Plan.
[227] 220 ILCS 5/16-111.5B(a)(2).
[228] 220 ILCS 5/16-111.5B(a)(3).
[229] 220 ILCS 5/16-111.5B(a)(3)(C).
[230] 220 ILCS 5/16-111.5B(a)(3)(D).
[231] 220 ILCS 5/16-111.5B(a)(3)(E).
[232] See 220 ILCS 5/8-103(d).
[233] 220 ILCS 5/16-111.5B(a)(3).
[234] 220 ILCS 5/16-111.5B(a)(4).
[235] 220 ILCS 5/16-111.5B(a)(5).

9.1 Incremental Energy Efficiency Approved in Previous Plans

The IPA's 2017 Procurement Plan is the fifth plan to include energy efficiency programs under Section 16-111.5B. Table 9-1 summarizes the total approved MWh of programs from each previous Procurement Plan and the MWh from the programs proposed for approval in this Plan. For previous years, actual MWh performance varied from these approved levels.

Table 9-1: Projected Savings (MWh) from Section 16-111.5B Programs From Prior IPA Procurement Plans and Proposed in this Plan

Delivery Year	Ameren Illinois	ComEd
2013 – 2014 (Approved in 2013 Plan)	**70,834**	**118,515**
2014 – 2015 (Approved in 2014 Plan)	**65,680**	**430,609**
2015 – 2016	**169,442**	**830,008**
Approved in 2014 Plan	-	547,904
Approved in 2015 Plan	169,442	282,104
Moved from 8-103	*88,203*	*247,648*
Third-Party RFP	*81,239*	*34,456*
2016 – 2017	**230,228**	**984,052**
Approved in 2014 Plan	-	611,958
Approved in 2015 Plan	169,690	284,641
Moved from 8-103	*93,569*	*241,541*
Third-Party RFP	*76,121*	*43,100*
Approved in the 2016 Plan	60,538	87,453
2017 – 2018 (Proposed in this Plan)	**190,172**	**887,268**
2018 – 2019 (Proposed in this Plan)	**209,102**	**641,473**
2019 – 2020 (Proposed in this Plan)	**220,936**	**655,646**

The MWh totals listed above are the approved goals for programs approved in prior procurement plans, and reflect programs available to all potentially eligible retail customers.[236] Please note, however, that the actual impact on IPA energy procurement each year is prorated to the portion of those customers who are actually eligible retail customers (i.e., take supply service from ComEd or Ameren Illinois). See Sections 3.2.3 and 3.3.3 for a discussion of what portion of potentially eligible retail customers are forecast to actually be eligible retail customers.

The IPA's 2016 Procurement Plan included the approval of seven programs for Ameren Illinois and 11 for ComEd. Those programs were all approved for just one year. As with the approval of prior procurement plans including energy efficiency programs under Section 16-111.5B of the PUA, the 2016 Plan approval process afforded the Commission the opportunity to further clarify contested policy and statutory interpretation issues related to Section 16-111.5B implementation.[237] As more extensively discussed in Section 9.2 below,

[236] While the IPA generally procures only for the "eligible retail customers" of participating utilities, Section 16-111.5B programs are available to "all retail customers whose electric service has not been declared competitive under Section 16-113 of this Act and who are eligible to purchase power and energy from the utility under fixed-price bundled service tariffs, regardless of whether such customers actually do purchase such power and energy from the utility." (220 ILCS 5/16-111.5B(a)(3)(C))

[237] Of the fourteen contested issues from Docket No. 15-0541, eight concerned implementation of Section 16-111.5B's energy efficiency procurement provisions.

the Commission directed that specific unresolved issues be addressed through workshops held by the Stakeholder Advisory Group ("SAG") for further consideration. The SAG 2016 Section 16-111.5B Workshop Subcommittee Report, attached as Appendix H, reflecting the input of and feedback from participating parties (including the Agency, Commission Staff, ComEd, Ameren Illinois, and other non-financially-interested stakeholders), summarizes the parties' consideration of these issues and contains 2016 consensus language agreed to by participants (some of which constitutes an update of consensus items developed in prior years' workshops and approved in prior plan approval proceedings).

The IPA's 2017 Procurement Plan marks the second instance in which approval of incremental energy efficiency programs included via Section 16-111.5B is sought for a delivery period for which Section 8-103 utility energy efficiency program portfolios are not yet approved—a timing issue set to occur every third year under existing law. [238] As highlighted in the 2016 Plan, this presents unique challenges, in recognition of which the Commission made the following statement in approving the 2016 Plan:

> The Commission recognizes the challenges of "expansion" of Section 8-103 programs when the portfolio for such programs has not yet been approved. This creates a natural tension: while unapproved programs cannot easily be "expanded," the law calls for IPA plans to fully capture the potential for all achievable cost-effective savings, which presumably includes expanded Section 8-103 programs.
>
> In recognition of this challenge, the Commission directs the SAG to address this topic at workshops. These workshops should demonstrate a genuine commitment to resolving this problem, consistent with the goal of capturing all achievable energy savings. It should also consider solutions such as the conditional approval of Section 8-103 program expansions in the IPA's 2017 Plan and potential contractual mechanisms to accommodate the uncertainty that is present when there is an unapproved Section 8-103 portfolio.[239]

These challenges were discussed extensively at workshops, and each utility's approach is discussed in more detail in the sections below.

Likewise, because the 2017 Procurement Plan features the approval of energy efficiency programs concomitant with consideration of the utility's upcoming three-year portfolios, RFPs issued by the utilities offered bidders the opportunity to bid programs of up to three years in length (as approved Section 16-111.5B programs may then be incremental to an approved Section 8-103 program for the full three-year timespan of the Section 8-103 portfolio).[240]

9.2 2016 Section 16-111.5B SAG Workshop Subcommittee

As referenced above, in approving the 2016 Plan, the Commission directed parties to consider multiple issues through SAG workshops. This approach was also taken in approving prior years' plans. SAG workshops allow for parties to potentially reach agreement on otherwise contested issues, and the IPA believes such workshops generally result in better and more thoughtful outcomes given the increased time allowed for consideration of complex issues (relative to a 90 day docketed proceeding) and the more candid, less adversarial nature of a workshop process (relative to plan approval litigation).

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[238] Section 8-103(f) of the PUA provides that, every third year after 2013, "each electric utility shall file, no later than September 1, an energy efficiency and demand-response plan with the Commission." (emphasis added) While this means that the utilities' Section 8-103 dockets have begun prior to the Plan approval proceeding, Section 8-103(f) also provides that the Commission shall "issue an order approving or disapproving each plan within 5 months after its submission"— late January 2017, after a decision is required from the Commission in the IPA Procurement Plan proceeding.

[239] Docket No. 15-0541, Final Order dated December 16, 2015 at 91-92.

[240] This approach was expressly approved by the Commission in Docket No. 15-0541, with the Commission noting that "[l]onger contracts can promote broader participation and better results." Id. at 80.

2016 Section 16-111.5B workshops were organized and administered by the Future Energy Enterprises, LLC, which serves as the SAG Facilitation Team. Participants included Ameren Illinois, ComEd, Northern Illinois Gas Company d/b/a Nicor Gas ("Nicor Gas"), the Office of the Attorney General of Illinois ("IL AG"), the Illinois Department of Commerce and Economic Opportunity ("DCEO"), ICC Staff, the IPA, the Natural Resources Defense Council ("NRDC"), and the Environmental Law and Policy Center ("ELPC").[241] Due to the sensitive nature of the issues and the concern that potential bidders for 2017 third-party energy efficiency ("EE") programs could receive an unfair advantage by participating in IPA Workshop Subcommittee meetings, parties determined that it would not be appropriate to include financially-interested parties (i.e., potential bidders) in workshop participation.

Taken broadly, five discrete issues identified by the Commission in the Docket No. 15-0541 Order were taken under consideration by the SAG workshop process:

1. Review and Update 2013 and 2014 Consensus Items (Consensus Items from Prior Years' IPA Workshops)

2. What TRC-related information do utilities need to provide to the IPA for its analysis of duplicative programs?

3. How will the Section 16-111.5B bids be conducted when the Section 8-103 programs for the next three-year EE Plan have not yet been approved?

4. Administrative cost tracking, categorizing, reporting and analysis (Total Resource Cost ("TRC") Test analysis for Section 16-111.5B programs)

5. Develop a plan to ensure that Section 16-111.5B contracts receive the same level of scrutiny as Section 8-103 contracts. How can performance risk be addressed through the Section 16-111.5B RFP process?

These issues were considered across 10 workshop subcommittee meetings spread over a span of six months from late January to late July. The workshop meetings and associated work resulted in the development of the "Report from the Illinois Energy Efficiency Stakeholder Advisory Group (IL EE SAG) 2016 Section 16-111.5B Workshop Subcommittee" ("2016 SAG Report"), included with the Plan as Appendix H.

The IPA believes that significant and meaningful progress was made in the consideration of all five issues outlined above, and the Agency thanks the SAG facilitation team and workshop participants for genuine, committed efforts toward consensus resolution of complex challenges. While the fourth and fifth issues resulted in some unresolved differences between parties — an expected result when parties are working in good faith toward solutions but have different perspectives, different experiences, and are accountable to different constituencies — none were so significant that the IPA believes further clarification from the Commission is absolutely essential for approval of the 2017 Plan and proposed energy efficiency programs.[242] Given that the majority of contested issues from the 2016 Plan approval litigation concerned issues arising under Section 16-111.5B, and the success that these same parties had in reaching consensus over a wide range of issues in subsequent workshops, the IPA believes this demonstrates that the 2016 Section 16-111.5B subcommittee workshop process was a laudable success.

As stated above, the 2016 SAG Report reflects input and feedback from all participants, and includes new and updated consensus language agreed to by participants for Commission approval. For increased transparency

[241] Representatives from the Illinois Industrial Energy Consumers ("IIEC") did not participate in IPA Workshop Subcommittee meetings, but requested to be included on the email distribution list to follow the discussion of issues.

[242] Other parties, of course, may raise issues for Commission consideration should they feel that clarification is necessary, and indeed stated in comments that clarification would be very helpful.

and continued consistency with the approach taken in prior procurement plans, that consensus language is set forth in Section 9.3.

9.3 2016 Workshop Consensus Items

Included below are the specific consensus items agreed to by participants to the 2016 Section 16-111.5B Workshops. These items, taken from Attachment A of the Workshop Subcommittee Report (included as Appendix H), are intended to update—and thus replace—consensus items previously approved by the Commission, including through approval of the 2016 Plan. As in the past, the IPA requests that the Commission expressly approve the consensus items to be binding upon the energy efficiency programs approved as part of the IPA's 2017 Procurement Plan for the planning of, implementation of, reporting on, and evaluation, measurement and verification of savings achieved by such programs, as well as binding upon parties up to the development of the IPA's 2018 Procurement Plan (at which time any changes to the list below may be considered).

<u>*Section 1: Section 16-111.5B Programs*</u>

This section references various policies for electric utilities managing Section 16-111.5B Programs.

i. *Planning:*

   a. *Section 8-103 Portfolio savings and 16-111.5B Program savings shall be tracked separately. Some Programs may be funded by both Sections 8-103 and 16-111.5B, in which case an allocation methodology for savings may be used.*
   b. *Section 8-103 and 16-111.5B budgets shall be tracked separately.*

ii. *Procurement:*

   a. *Electric utilities shall include all bids and bid reviews in their Energy Efficiency Assessments submitted to IPA pursuant to Section 16-111.5B(a)(3).*
   b. *Under the use of pay for performance contracts, the Commission may authorize on a Program basis, a maximum energy savings target and spending cap.*
   c. *To the extent that parties are concerned with Energy Efficiency replacing power purchase needs under Section 16-111.5B, it would be appropriate for the IPA, in consultation with ICC Staff, the utilities and/or Evaluators, to estimate the amount that the Section 16-111.5B Programs reduce the IPA's need to procure supply, to serve as a check on the utilities' original estimate required by Section 16-111.5B(a)(3)(G), and to provide useful information to Customers.*
   d. *The Commission may determine how the additional information provided pursuant to Section 16-111.5B (a)(3)(D)-(E) should be used as necessary to resolve issues raised in docketed proceedings.*

iii. *Coordination of Section 8-103 and Section 16-111.5B Programs:*

   a. *The utilities shall identify new or expanded Cost-Effective Energy Efficiency Programs or Measures that are incremental to those included in Energy Efficiency and demand-response Plans approved by the Commission pursuant to Section 8-103 of the Illinois Public Utilities Act in the annual Energy Efficiency Assessment they submit to the IPA, unless Section 8-103 Programs are already expected to achieve the maximum achievable Cost-Effective savings. An "expansion" of a Section 8-103 Program per Section 16-111.5B is not strictly defined.*
   b. *When Section 8-103 Programs are expanded, they should be administered in such a way as to facilitate utility tracking of the original Section 8-103 portion and the Section 16-111.5B portion of the expanded Program.*

iv. *Cost-Effectiveness:*

a. *All Section 16-111.5B Programs included in the Section 16-111.5(b) Procurement Plan must be Cost-Effective at the planning stage, including Programs serving Low Income Customers.*
b. *Cost-ineffective Programs should be dropped during the Procurement Plan proceeding or prior to implementation, should analysis show that the Program is no longer Cost-Effective.*
c. *Section 16-111.5B(a)(3)(D) can be interpreted as the Utility Cost Test, and should be calculated for each Program.*

v. Budget Allocation:

a. *Funds approved pursuant to Section 16-111.5B shall not be spent on Programs that were not approved in an IPA Procurement Plan docket.*
b. *Expenditures on evaluation should be capped for the Section 16-111.5B Programs as they are for the Section 8-103 Programs. Each Program's evaluation budget should not be restricted to three percent (3%) of the Program budget, but evaluation costs should be limited to three percent (3%) of the combined Section 16-111.5B Programs' budget.*

vi. Savings:

a. *When a Section 8-103 Program is expanded into Section 16-111.5B, the savings from the expanded portion of the Program count toward Section 16-111.5B. However, the savings from the non-expanded portion of the Program count toward the utility's Section 8-103 savings goal. Commensurately, when a Section 16-111.5B Program is expanded into the utility's Section 8-103 Portfolio, the savings from the expanded portion of the Program count toward the utility's Section 8-103 savings goal, while the savings from the non-expanded portion of the Program count toward Section 16-111.5B.*

vii. Management of Programs:

a. *Expenditures shall be reviewed for operational prudence and reasonableness in a docketed reconciliation proceeding. However, there is no proceeding required for energy savings per Section 16-111.5B.*

<u>*Section 2: Program Flexibility and Budgetary Shift Rules*</u>

i. Expansion of Section 16-111.5B Programs

a. *Electric utilities should have the capability for any of the Section 16-111.5B Programs to be able to expand into the Section 8-103 Portfolio for a given Program Year, at the utility's discretion, if: (1) the Section 16-111.5B savings goal for the Program from the Commission Order in the procurement plan case or compliance filing/contract is achieved, and the approved budget (from Commission Order in the Procurement Plan docket) is exhausted; and (2) the electric utility has budget available in the Section 8-103 Portfolio.*

ii. Budget Shifts

a. *The utilities may shift up to 20% of the budget across Program Years for multi-year Section 16-111.5B Programs, assuming the shift remains within the total approved multi-year Program budget, to allow for successful Programs to continue operation in the early (or later) Program Years of a multi-year contract. In such a situation, the kWh savings goals and budgets would be cumulative for the number of years of the contract. Electric utilities should make the vendor aware of the expansion and budget shift options in advance so as to help avoid Program disruption.*

iii. Vendor Contracts

a. The utilities have primary responsibility for prudently administering the contracts with the vendors approved by the Commission for the Section 16-111.5B Energy Efficiency Programs.

b. Utilities should have flexibility to structure Section 16-111.5B contracts in a manner which best balances the potentially competing objectives of making the procurement process attractive to as many bidders as possible, protecting ratepayers and providing confidence that the savings which are proposed/bid will actually be delivered.

c. Once the Commission approves the procurement of Programs pursuant to Section 16-111.5B(a)(5), the utilities and approved vendors should move forward in negotiating the exact terms of the contract based on the terms of the RFP and the bid itself (and that are "not significantly different" from the initial bid), with the clarification that negotiation around details of the contract/scope of work/implementation plan still might need to occur depending on a variety of factors (e.g., lessons learned since bid submittal, updates to the IL-TRM and NTG, changes in the market, desire to add new Measures).

d. The utilities should use reasonable and prudent judgment in negotiating the exact terms of the Section 16-111.5B vendor contract after Commission approval and should rely upon the available information and ensure that any modifications continue to result in a Cost-Effective Program. Negotiations may result in reasonable adjustments to savings goals for the Program in comparison to the amount proposed in the bid and reasonable and prudent modifications to the cost structure which are in line with the original design. Once a Section 16-111.5B Program is approved by the Commission, the vendor has the opportunity to negotiate different participation rates and/or Measure levels. Once the contract is signed, those Measures / participation rates will be fixed for the life of the contract for the purpose of setting annual savings goals. However, the vendor and the utility may negotiate a change in the Measure mix, for Program implementation and goal attainment purposes. Some degree of flexibility within a Program is allowed for vendors implementing Programs under Section 16-111.5B. Vendor flexibility is not allowed insofar as the modifications to the Section 16-111.5B Program result in the following: (1) less confidence in the quality of service; (2) the addition of new Energy Efficiency Measures with no confidence in the savings; (3) duplicates other Energy Efficiency Programs; (4) a cost-ineffective Energy Efficiency Program; or (5) a completely different Energy Efficiency Program proposed in comparison to what was bid and approved.

e. The utilities/IPA should share the description of the vendor's Program included in the draft Procurement Plan with the vendor to help ensure the Program is accurately characterized.

f. A process for vendors to submit Program changes should be clearly conveyed to all Section 16-111.5B vendors by the utilities. If a vendor decides to add (or remove) Energy Efficiency Measures midstream, they should seek approval from the utility for such changes prior to implementing the change in order to allow for possible contract renegotiations. Vendors are allowed to receive credit for energy savings from implementing new Energy Efficiency Measures if they have received pre-approval from the utility for adding that new Energy Efficiency Measure. To help protect against gaming, any Energy Efficiency Measure that has not received pre-approval from the utility or is not included in the vendor's approved proposal should not be considered for energy savings.

g. The utility should notify the IPA, ICC, and the SAG when it has stopped negotiations with an approved Section 16-111.5B Program vendor and a contract agreement cannot be reached, and if it has terminated a contract with an approved Section 16-111.5B Energy Efficiency Program vendor. The utility should notify the Commission in a filing in the IPA Procurement Plan case in which the Program was approved (similar to the approach ComEd used for PY7 and the approach proposed by Ameren in Docket No. 13-0546, Order at 112; Ameren RBOE at 14).

h. The utilities should notify the SAG and keep the IPA apprised of any expected shortfalls in savings from approved Section 16-111.5B Programs. The utility should notify the Commission of changes made, in comparison to the approved Section 16-111.5B Programs.

i. ComEd and Ameren Illinois will provide all costs allocated between Section 8-103, 8-104 and 16-111.5B Programs in the Program Administrator Annual Report produced pursuant to the provisions *of Subsection 6.6 Program Administrator Annual Summary of Activities (Annual Report) set forth in Policy Manual Version 1.0, ICC Final Order Docket No. 15-0487 Appendix.*

j. *For purposes of the Section 16-111.5B Programs Adjustable Savings Goals policy approved in Illinois Energy Efficiency Policy Manual Version 1.0 (ICC Final Order Docket No. 15-0487 Appendix), the Measure participation levels identified in the executed contract to derive the energy savings goals shall be fixed for the life of the contract for the purpose of setting the annual adjusted energy savings goal.*

<u>*Section 3: Evaluation Policies*</u>

i. *Technical Reference Manual*

a. *The Illinois Statewide Technical Reference Manual (IL-TRM) and the IL-TRM Policy Document apply to Section 16-111.5B Programs.*
b. *For Section 16-111.5B Programs, there may be limited circumstances where deviation from the IL-TRM may be appropriate; the utility/vendor should have the option to make the case for the circumstance. However, the IL-TRM values must also be provided for comparison purposes, by filing in the IPA Procurement Plan docket in which the proposed Section 16-111.5B Programs are considered for approval.*

ii. *Evaluation of Section 16-111.5B Programs*

Evaluators and electric utilities managing Section 16-111.5B Energy Efficiency Programs shall follow these evaluation policies:

a. *Evaluation of the Section 16-111.5B Programs should be performed by the Section 8-103 Program Evaluators, and coordinated with Section 8-103 Programs.*
b. *Ex-post Cost-Effectiveness analysis should be performed for the Section 16-111.5B Programs, using actual participation data, consistent with Section 8-103 evaluation policies and practices.*
c. *Section 16-111.5B Program evaluation reports should be filed in the IPA Procurement Plan docket in which the Programs were approved.*
d. *Evaluation plans for Section 16-111.5B Programs should be tailored based on the size and content of the Program. Consistent with the Section 8-103 evaluation process, Evaluators may conduct process evaluations where justified, to encourage improvement in the implementation of the Section 16-111.5B Programs. The value of this effort must be weighed against the cost of conducting such an evaluation for a Program that is: a) not unique or innovative; b) achieves very small savings; or c) is not likely to gain traction as an ongoing Program either in future Section 16-111.5B Program processes or as part of the Section 8-103 Portfolio.*

In addition, the 2016 Workshop report produced consensus language regarding the specific issues that the Commission asked for SAG workshops to consider in the Commission's Order in Docket No. 15-0541. While the application of that language is in many instances designed to be more specific to this year's Plan and associated circumstances than the broader principles governing implementation of Section 16-111.5B outlined above, the Agency requests the same express approval of that consensus language as well.

9.4 Policy Issues for Consideration in the 2017 Plan

In prior years, the IPA has highlighted specific policy issues for further consideration by interested parties in offering comment on the draft Plan or by the Commission in approving the Plan. While the IPA appreciates the significant time and effort that has been put into workshops each year by stakeholders, the Agency highlights the following issues in this draft Plan as ones where more consideration may be needed, and clarification or refinement of past policies and procedures may be warranted.

9.4.1 Scale of Section 16-111.5B programs

As shown in Table 9-1 and discussed further in the sections below, when evaluated on the basis of the amount of savings projected to be achieved, the size of the Section 16-111.5B programs may have peaked in the 2016-2017 delivery year. As bidders continue to become more familiar with the Section 16-111.5B process, and given that this year's RFP offered programs for three years in length, this phenomenon is unexpected.

One possible explanation is that this result could constitute an accurate reflection of the market for energy efficiency in Illinois. However, another possible explanation is that this could be an indicator of barriers to participation by potential bidders. If it is the latter, then what efforts should be undertaken to attempt to increase the number and scale of bids for cost-effective energy efficiency programs?

One possible suggestion is that the utilities could conduct more extensive outreach to disseminate the RFPs in order to find new potential bidders. As discussed below in the review of the bids received for each utility, outreach has been fairly limited. It appears that existing outreach efforts are effective in reaching established energy efficiency industry firms, but it is less clear how well it has reached new firms with the potential to offer new and innovative approaches.

Another possible suggestion is that the utilities could use the Potential Studies required under Section 16-111.5B(a)(3)(A) (and perhaps other screening tools) to specifically solicit new programs that are not part of approved Section 16-111.5B and 8-103 suite of programs. These studies are extensive and paid for by ratepayers, and often yield rich information regarding potential energy efficiency program opportunities. While these potential studies may also be used by the utilities in the development of their Section 8-103 portfolio, the IPA observes that they have, to date, provided limited utility during the consideration of Section 16-111.5B programs.

After receiving comment on its draft Plan, the IPA believes that the best solution for ensuring that the RFP process is able to "fully capture the potential for all achievable cost-effective savings, to the extent practicable" as required by the law would be for the Commission to a) require SAG workshops shortly after the conclusion of the proceeding approving the 2017 Plan at which the utilities and stakeholders can discuss more effective strategies for marketing Section 16-111.5B RFPs and b) to require that the utilities' potential studies and stakeholder feedback be utilized in ensuring that the RFPs, while remaining open-ended, specifically identify any program areas for which bids should be actively sought.

9.4.2 Improving/Refining Bids

There are several potential refinements to the RFP process that could improve the bids received. Concerns have been raised that the nature of the Section 16-111.5B RFP process could allow bidders to propose programs with excessive administration costs by finding headroom in the TRC analysis. Likewise, another concern that has been expressed is a desire for more post-bid negotiations between the utilities and bidders in order to refine/improve the scope, scale, price, etc. of bids. Both concepts suggest that there could be potential to move away from a process where only minor adjustments are made to bids (e.g., adjusting incorrect savings levels provided by bidders) to a model where active negotiations are undertaken in order to improve the quality and value to ratepayers of the proposed programs.

Post-bid negotiations, however, could create significant challenges with successful implementation. With the requirement that the utilities provide an assessment of the bids to the IPA by July 15 of each year, there is limited time available to utilities to undertake such negotiations after a bid is received. Further, the Agency fears that bidders could use a negotiation process as an opportunity to change an initially submitted proposal into something fundamentally different and less connected to the bidder's actual capacity just to attain program approval. Worse still, that dynamic that could eventually result in proposed initial program designs which reflect a bidder's best-case scenario, submitted under the understanding that should the utilities or others be uncomfortable with assumptions made in that proposal (or should that initial proposal fail the TRC), there exists room for negotiation.

Based upon the IPA's experience with its other procurements (e.g., block energy, capacity, renewables), the best mechanism for driving bidders to produce the most honest and accurate proposals oriented around minimizing costs and maximizing benefits may instead be through having clear and explicit processes and rules, and increasing participation to encourage competition between bidders. That approach can drive positive results even if a bid's proposed terms are fixed. Such improvements could perhaps be achieved through improvements to the RFP process as suggested above, although the IPA acknowledges that not every potential third-party energy efficiency program features a cadre of capable bidders equipped to compete. Nevertheless, further examination of this issue may be warranted, and while the IPA is not recommending requiring a post-bid negotiation process at this time, other parties may have more specific proposals worth of consideration in the Plan approval proceeding.

The IPA also has observed that bidders have very rarely participated in the comment process on the draft Plan or the docketed Plan approval proceeding before the ICC. It is not clear to the IPA whether bidders view their program's lack of inclusion in a Plan as the end of their bid, and consideration of certain programs could often benefit from bidder participation in either of these processes. The IPA's proposed solution would call for the communications to bidders about their bids being clarified to make clear to those bidders that they have the right to participate in either the comment process or the docketed proceeding, and that such participation will not prejudice the evaluation of their bid. While the approach taken by the bidder in this year's comment process was seemingly directed at changing a proposed program structure purposes of establishing cost-effectiveness, there are other circumstances in which clarifications and corrections of incorrect assumptions could be made through the comment process to enhance the completeness and accuracy of bid evaluation, or bidder feedback through comments could help refine best practices in bid solicitation and review.

The use of pay for performance contracts, holdbacks, and in the case of Ameren Illinois, surety bonds has been the way in which the utilities have addressed the risk of programs not achieving savings goals. Unlike Section 8-103 programs (featuring goals developed by the utilities), savings goals for Section 16-111.5B programs are proposed by the bidders. While many programs have performed very successfully, other programs have been less successful, and in one case, as extensively litigated in ICC Docket No. 14-0567, a vendor bankruptcy led to costs incurred that did not result in any energy savings. While the IPA appreciates that the ICC must consider whether utilities prudently manage their expenditures, balance must be achieved between necessary risks to achieve cost-effective energy reductions and completely insulating ratepayers or shareholders from any lost expenses.

One suggestion for achieving this balance could be general guidance from the Commission about terms and conditions utilities should include in their contracts offered to vendors, as such clarity could also increase vendor confidence in the program structure. While the IPA is not seeking to litigate each and every utility energy efficiency contract term through a 90-day proceeding addressing a host of other, non-energy efficiency issues, the Plan approval process may allow for general Commission guidance and any specific, discrete questions about contract terms (such as the propriety of surety bonds) to be addressed.

For the past two years, the extent to which programs can include gas savings has been an issue for some of Ameren Illinois' bids. As discussed in Section 9.5.4 below, Ameren Illinois has included a provision in its RFP that attempts to limit measures that have gas savings; it has used that provision to recommend rejection of certain programs or to evaluate others with none or only some of their gas savings. The IPA does not agree with this approach, believing it is inconsistent with the law. The IPA believes that programs (as opposed to specific measures within the program) should be evaluated in their entirety using both the gas and electric savings—as done in each year prior to this year, as done by ComEd in its submission, and in the view of the IPA, as intended by the plain language of the law.[243]

9.4.3 Other Considerations

In Docket No. 13-0546, the Commission approved a process by which duplicative programs that are otherwise cost-effective could be excluded from the Plan. This process has worked reasonably well. Since that time, additional concerns about bids have arisen. For example ComEd has flagged bidder "performance risk" as an issue, one discussed somewhat extensively in filings around the approval of the 2016 Plan. As discussed more specifically in Section 9.6.5, certain bidders have consistently failed to achieve meaningful savings. While pay for performance contracts limits the risk to ratepayers from underachieving programs, there are still administrative and overhead costs associated with these programs and the potential for very poorly performing programs and vendors to produce negative customer experiences and "poison the well."

While the IPA believes that it should not unnecessarily limit Section 16-111.5B offerings, ComEd has proposed a pragmatic and appropriately permissive approach to performance risk for this year's Plan (and Ameren Illinois applies similar logic in a more limited scale in its consideration of duplicative programs). It may be worth formally approving a fixed process or test under which programs identified as posing too significant a performance risk could be removed from inclusion in the Plan. Combined with the idea suggested above about how to refine and improve bids, a better process for addressing particularly weak bids could result in a better overall suite of programs.

9.5 Ameren Illinois

Ameren Illinois' submittal to the IPA prepared in compliance with sections 16-111.5 and 16-111.5B of the PUA is included in Appendix B of this Plan. The submittal includes six appendices which may be found on the IPA website posting of the draft 2017 Procurement Plan at www.illinois.gov/ipa. Two of the Appendices (4 and 6) in Ameren Illinois' submittal contain confidential data and are not included in the Appendices of this Plan. Ameren Illinois also provided the IPA with its most recent energy efficiency Potential Study, and on a confidential basis, copies of all the bids received.

The IPA believes that Ameren Illinois' submittal meets the requirements of Section 16-111.5B(a)(1)-(3) and that the programs identified by the IPA as "cost-effective" should be approved by the Commission pursuant to Section 16-111.5B(a)(5).

9.5.1 Ameren Illinois Bids Received

Ameren Illinois received 24 bids: eight for the residential sector, and 16 for the business sector. All bids sought contracts for three years. Of those 24 program proposals, Ameren Illinois classified two as "Not Responsive" (discussed further below in Section 9.5.4); 11 did not pass the TRC; and one was deemed duplicative (discussed in Section 9.5.5); leaving 10 programs that Ameren Illinois recommended as acceptable in its Assessment. For three of those programs, Ameren Illinois recommended that additional conditions be applied (discussed in Section 9.5.6). As discussed in Section 9.5.4 the two programs classified as "Not Responsive" were subsequently analyzed by the IPA, passed the TRC, and are thus included in this Plan.

The 24 bids received represents a decline from the 32 bids received by Ameren Illinois in 2015, a surprising result given the potential for three-year contracts for winning bidders through this year's solicitation (only one year contracts were available in the prior year's solicitation). This reduction in bidder participation may raise concerns about whether Ameren Illinois should be more aggressive in soliciting bids. For this year, after development of its RFP (a process which considered the input of the Agency and interested stakeholders, as

[243] Section 16-111.5B(b) expressly requires that "the term 'cost-effective' shall have the meaning set forth in subsection (a) of Section 8-103" (i.e., "means that the measures satisfy the total resource cost test"), which in turn expressly requires that "avoided natural gas utility costs" be included in a cost-effectiveness calculation.

envisioned by Section 16-111.5B(a)(3) of the PUA), Ameren Illinois only posted the RFP to the Association of Energy Service Professionals ("AESP") website and conducted no further outreach. Ameren Illinois confirmed that this approach is consistent with its past practice (including in 2015, when it received 32 bids), and AESP is also the primary (but not only) avenue used by ComEd in soliciting bids—and ComEd received more bids in 2016 than in 2015. While posting to the AESP website appears to be sufficient to reach established industry participants, it may be less effective in reaching new participants who could provide innovative new programs.

A second issue that may have complicated bidder participation is the introduction of a surety bond requirement for winning bidders (noticed to potential bidders in the RFP) as a mechanism to help protect ratepayers against potential program performance issues. It is unclear to the Agency whether a measure such as surety bonds is necessary given the pay-for-performance nature of Section 16-111.5B energy efficiency contracts, and if a surety bond requirement produces a chilling effect on participation, it could actually have a net negative impact on ratepayers by reducing the number of cost-effective programs included in the IPA's electricity procurement plan. As with bid solicitation, this is an issue for which the Agency has limited visibility as to its impacts.

9.5.2 Ameren Illinois Bid Review Process

In conjunction with the bid review conducted by Ameren Illinois and stakeholders,[244] Ameren Illinois' consultant AEG performed an analysis on the bids. All documents submitted by the bidders were reviewed, including the program proposal, measure information spreadsheet, and any supporting documentation. AEG reviewed the detailed savings calculations provided by the bidders and then independently calculated savings for each individual measure where a Technical Reference Manual ("TRM")[245] equation is applicable to verify compliance with the TRM. If the results matched, compliance was verified. If AEG found minor discrepancies in the bidder equations that were not in compliance with TRM Ver. 5.0, AEG adjusted the savings so they were in compliance with that version of the TRM (with the exception of one behavioral program, as discussed further below). If there were major discrepancies, AEG went back to the bidder to gather more information to determine why there were differences from the bidder savings and TRM calculations.

In all but one case, the issues were resolved and AEG was able to verify TRM compliant savings. In the instance where AEG calculations differed from the bidder calculations, this occurred because the bidder sought to use calculations based on a different state's TRM. AEG instead independently calculated savings values using the Illinois TRM were utilized, and the Agency believes these were appropriate adjustments.

9.5.3 Review of Ameren Illinois TRC Analysis

The IPA reviewed the TRC analyses provided by Ameren Illinois using the BENCOST tool provided by the utility. The BENCOST model was updated this year to include quantifiable non-energy benefits for water and O&M expenses, a reserve adjustment to the cost of capacity, and an estimate for the future price of carbon.[246] In conducting its review, the IPA reviewed submitted inputs for accuracy and reasonableness, and performed "stress testing" around program cost-effectiveness parameters (such as adjusting the forward energy price curve, levels of administrative costs, etc.) to develop a better understanding of the impacts of adjustments to the model. The IPA generally concurred with the Ameren Illinois inputs, assumptions, and methodology.

[244] Stakeholders who signed non-disclosure agreements with Ameren Illinois and participated in a series of bid review meetings included the IPA, the Office of the Illinois Attorney General, ELPC, NRDC, CUB, and IIEC. ICC Staff also participated, but did not sign a non-disclosure agreement (citing existing statutory obligations to maintain the confidentiality of information).

[245] The TRM is a guidance document developed through the SAG process and approved by the Commission. It provides standard values and methodologies for calculating savings and impacts from energy efficiency measures and programs.

[246] Ameren Illinois initially submitted its analysis using a methodology based on a $25/ton price for carbon, but subsequently updated the analysis to reflect a methodology that used the price impacts from the U.S Energy Information 2016 Annual Energy Outlook which reflect the implementation of the Clean Power Plan. The revised methodology appears consistent with the methodology used by ComEd.

Ameren Illinois included a blanket administrative cost adder of 11.89% for all programs in evaluating individual program cost-effectiveness.[247] This administrative cost adder is lower than the 13.58% proposed by Ameren Illinois last year, and is nearly the same as the approved 11.5% administrative cost adder from last year's plan approval (a percentage adder which reflected the removal of non-scalable costs for the Potential Study consistent with the Commission's directive in Docket No. 15-0541).[248]

According to its submittal, Ameren Illinois's 11.89% administrative cost adder is composed of 3.97% for Evaluation, Measurement and Verification (compared to 3.5% last year),[249] 5.61% for administration (compared to 5% last year), and 2.3% for marketing, education and outreach (compared to 3% last year). In Docket No. 14-0588, the Commission required that the utilities "track administrative costs by program in order to aid in future determinations of appropriate administrative cost assumptions to use in the TRC analysis of the Section 16-111.5B programs."[250] Ameren Illinois provided follow-up information demonstrating costs incurred by program in substantiating actual administrative costs. These administrative cost levels appear to be within an expected range based on prior years, and that small changes to the administrative adder which could come from minor adjustments would not appear to impact which programs pass or fail the TRC.

Ameren Illinois (through its consultant AEG) adjusted the gross energy savings values for certain energy efficiency measures provided by bidders to more accurately reflect values in the Illinois TRM. While one such instance resulted in a disagreement by the bidder (who sought to apply values derived from another state's TRM), those adjustments appear to be reasonable to the IPA. Ameren Illinois (also through AEG) also adjusted certain net-to-gross ratios provided by bidders to reflect the NTG ratios recommended by Ameren Illinois' independent evaluator. Those adjustments appear reasonable to the IPA.

As with last year, the IPA observes that fewer proposed programs passed the Ameren Illinois TRC screening than the ComEd screening. While this could be a function of the bids themselves or the TRC methodology applied, it appears that lower energy and capacity prices in the Ameren Illinois service territory may also simply make the test more difficult to pass. Of the 11 programs that did not pass the TRC, values ranged from 0.15[251] to 0.98.[252]

In addition to calculating TRC values for each program, Ameren Illinois also provided Utility Cost Test ("UCT") results for each program (as required by Section 16-111.5B(a)(3)(D) of the PUA) and an assessment of the cost of procuring each individual energy efficiency program as compared to its calculation of the Cost of Supply (provided pursuant to Section 16-111.5B(a)(3)(E)). The calculation methodology and application of the Cost of Supply was a subject of significant debate in the consideration of the 2016 Plan, with the IPA believing that Ameren Illinois' approach to calculating the Cost of Supply—an approach which disregarded gas savings and transmission & distribution savings, which differed from Ameren Illinois' established practice from prior years, and which differed from (and continues to differ from) the ongoing practice of ComEd—was

[247] In its submittal, Ameren Illinois noted that this adder is only for the purpose of calculative cost-effectiveness, and that for the purposes of cost recovery they estimate the need to include an additional 1.55% to cover those non-scalable costs.
[248] See Docket No. 15-0541, Final Order dated December 16, 2015 at 97-98.
[249] Several commenters on the draft Plan raised concerns that this amount exceeded 3% given the 3% cap on "[t]he resources dedicated to evaluation" in 220 ILCS 5/8-103(f)(7) and consensus items regarding administrative cost adders. Against the backdrop of the Commission's Order in Docket No. 14-0588, however, the IPA's primary concern is whether the adder reflects actual costs. As the Agency has no reason to believe that this does not reflect actual administrative costs, the Agency is comfortable with using a 3.97% value.
[250] Docket No. 14-0588, Final Order dated December 17, 2014 at 224.
[251] This is the program for which Ameren Illinois did not accept the bidder's proposal to use values from another state's TRM; the IPA concurs with Ameren Illinois' determination to use Illinois TRM values.
[252] As discussed in Section 9.5.5, the program with a TRC of 0.98 was also determined to be duplicative. The highest TRC for a non-duplicative program was 0.85.

inappropriately restrictive, especially when used to advocate for the non-adoption of otherwise cost-effective energy efficiency programs.[253]

The IPA continues to have reservations about the methodology used by Ameren Illinois to calculate the Cost of Supply, and one program which passed the TRC test failed the Ameren Illinois Cost of Supply test. As the Agency's is directed by law to include "energy efficiency programs and measures it determines are cost-effective,"[254] and because "cost-effective" refers to a program passing the Total Resource Cost test[255] (which, by law, requires taking into account gas savings, as is done through the TRC but not through the Ameren Illinois approach to calculating "cost of supply"),[256] that program is included in this Plan. However, the Agency is mindful of the Commission's acceptance of the Ameren Illinois approach to calculating the Cost of Supply in Docket No. 15-0541, and the discretion the Commission exercised in deciding not to include two programs with positive TRC test results which failed Ameren Illinois' Cost of Supply analysis, and understands that it could again use its recognized discretion to disqualify that program.

9.5.4 Programs Deemed "Not Responsive to the RFP" by Ameren Illinois

Ameren Illinois determined that two proposals were not responsive to the RFP. In determining that such programs were not responsive to its RFP, Ameren Illinois referenced the following statement within the RFP:

> "The purpose of this RFP is to procure energy efficiency programs that acquire electric savings in accordance with Section 5/16-111.5B of the Act. Accordingly, any programs or measures designed to acquire gas savings will not be accepted. However, if an electric program design captures incidental gas savings through multi-fuel measures, it may be considered. Such savings will be considered for purposes of the TRC test."

Ameren Illinois contends two of the proposals did not meet this requirement through too great a focus on gas savings, and therefore it did not fully evaluate these two proposals.[257]

9.5.4.1 Policy Implications

The Agency understands Ameren Illinois' concern that the IPA procurement plan process could include the approval of energy efficiency programs that might otherwise be funded by gas ratepayers (for instance, pursuant to Section 8-104 of the PUA) rather than a potentially distinct universe of electric ratepayers taking electric distribution service from Ameren Illinois. Conceptually, IPA procurement plans—and the IPA itself—generally address only electricity load requirements and not gas supply. However, the Agency is concerned that a disqualifying approach in the treatment of programs featuring considerable gas savings may be inconsistent with the Public Utilities Act and the IPA Act: Section 16-111.5B(b) of the PUA requires that "the term 'cost-effective' shall have the meaning set forth in subsection (a) of Section 8-103" (i.e., "means that the measures satisfy the total resource cost test"), which in turn requires that "avoided natural gas utility costs" be included in a cost-effectiveness calculation. While the IPA appreciates that adopting such programs could result in cross-subsidization of gas ratepayers by electric ratepayers, the intent of the General Assembly in enacting Section 16-111.5B, as taken from the language of the statute itself, appears to be that gas savings are not ineligible for consideration under Section 16-111.5B and in fact that such savings must be taken into

[253] The Agency notes that while the Ameren Illinois methodology for calculating Cost of Supply was unclear to some parties last year, causing the Commission to specifically state that "[i]n the future parties should present their method for calculating the cost of supply when asserting that an energy efficiency program exceeds that cost" (Docket No. 15-0541, Final Order dated December 16, 2015 at 105), Ameren Illinois provided a clear statement as to its Cost of Supply methodology in its July 15, 2016 submittal.

[254] 220 ILCS 5/16-111.5B(a)(4).

[255] 220 ILCS 5/16-111.5B(b) ("the term 'cost-effective' shall have the meaning set forth in subsection (a) of Section 8-103 of this Act"); 220 ILCS 5/8-103(a) ("'cost-effective' means that the measures satisfy the total resource cost test).

[256] 20 ILCS 3855/1-10 (requiring that the TRC analysis count, as a benefit, "other quantifiable societal benefits, including avoided natural gas utility costs").

[257] Ameren Illinois did not include these two programs in its submittal to the IPA, and therefore program descriptions for these programs were not included in that submittal's Appendix 5. In order to provide full information on these programs, the IPA has elected to include the program descriptions as included in the original bids in a separate appendix to this Plan, Appendix I.

account in assessing the cost-effectiveness of proposed programs. Further, as described below, using dollar savings (rather than BTUs, as Ameren Illinois employed) to compare the gas and electric impacts of programs demonstrates that due to the low price of gas compared to electricity, these programs actually generate more financial savings on the electric side. Because the concept of cost-effectiveness ultimately reduces impacts to their financial terms, the assertion that these programs have more gas savings than electric savings is arguably incorrect and not a justification for their exclusion.

Further, past practice under Section 16-111.5B has been to count all gas savings in cost-effectiveness determinations. Dismissing programs as inconsistent with the RFP and thus ineligible for inclusion on this basis constitutes a clear departure from past practice—and a departure that would be made not to disqualify programs which fail to produce electric savings, but driven instead by the proportion of gas savings versus electric savings for certain programs while still recognizing gas savings from other proposed programs as required by the law.

The IPA understands that this issue has been a topic of considerable discussion in past years, and that there are legitimate arguments on both sides.

9.5.4.2 Demand Based Ventilation Control Program

One of the programs Ameren Illinois considered to be inconsistent with its RFP is a demand control ventilation program which contains two measures—one for HVAC supply fans, and one for kitchen ventilation. The former reduces both gas and electric usage, while the latter only reduces electric usage. Overall, when normalized on a BTU basis, approximately two thirds of the energy reductions come from decreased gas usage—which exceeded the level that Ameren Illinois considered acceptable and was presented as their basis for not evaluating this program. However, examining savings by dollars saved rather than BTUs shows that two thirds of the financial savings resulted from reduced electric costs.

By considering the program non-responsive, Ameren Illinois did not initially provide a TRC result for the program, and the IPA requested that Ameren Illinois conduct that analysis using the gas savings. The TRC results subsequently provided by Ameren Illinois indicated that the TRC for the program was 1.98 and thus the program is cost-effective.[258]. The IPA believes that Ameren Illinois erred in excluding this program from its evaluation and includes it in the list of programs that are recommended for approval by the Commission.

On August 30, 2016 Ameren Illinois filed its next Section 8-103/8-104 Energy Efficiency Plan with the Commission in Docket No. 16-0413. That Plan includes Demand Control Ventilation measures that could be viewed as duplicative of this program. Since that Plan has not yet been approved by the Commission, the IPA does not consider the program to be "duplicative," as no overlapping program has yet been approved by the Commission. However, the Commission may wish to instead approve this program only on the condition that the comparable measures are not approved in Docket No. 16-0413. The IPA further notes that while Ameren Illinois did not develop a performance risk screenings approach as used by ComEd (see Section 9.6.5), the vendor for this program is also a vendor that was flagged as a potential performance risk in the ComEd review process.

9.5.4.3 Behavioral Program

The other program which Ameren Illinois considered to be inconsistent with its RFP was for a behavioral program that would be a continuation of an existing program. This bid contained multiple options including maintaining the current program scope or additionally expanding at various levels into all-electric households above and beyond continuing the current offering to dual-fuel households. When normalized on a BTU basis, half of the projected energy savings result from reductions in gas usage, but when savings are

[258] The IPA notes that *even if* gas savings were excluded (which, again, the IPA does not believe to be an appropriate methodology, as the law requires consideration of gas savings), the "electric only" TRC result would still be 1.34—thus making the program cost-effective on the basis of electric savings alone.

considered in dollar terms rather than BTU terms, the large majority of the savings result from savings of electricity.

While considering this program "Not Responsive," Ameren Illinois still conducted a TRC analysis of this program using both methodologies from the Illinois TRM version 5.0 but excluding the gas savings, as well conducted as using the previously generally accepted methodology for behavioral programs of looking at only one year of savings (a "No Persistence" model). The analysis was only of the core continuation program (and not the expansion into all-electric homes) and the program narrowly failed the TRC under both methodologies.

The IPA requested additional analysis to include gas savings as well as for the options included in the bid that expanded into all-electric homes.

Table 9-2 summarizes various TRC analyses conducted for this program. While Ameren Illinois provided in the additional analysis the TRC analysis of the expansion options, it did so treating them as standalone programs rather than offered in conjunction with the current program. However, the bid specifically described the expansion options as bundled with the core program,[259] and thus the IPA believes they must be evaluated as bundled together. These results reflect that bundling. It is the opinion of the IPA that the first row of this Table is the appropriate one for use in consideration of this program because it incorporates the methodology contained in the TRM that is currently in effect (TRM Version 5.0), as well as the gas savings required for cost-effectiveness determinations under the law.

Table 9-2: Behavioral Program TRC Sensitivity Analysis

Analysis	Continuation of 250,000 Homes	Continuation + Expand to 50,000 All-Electric Homes	Continuation + Expand to 100,000 All-Electric Homes	Continuation + Expand to 125,000 All-Electric Homes
TRM 5.0	**1.07**	**1.26**	**1.16**	**1.17**
TRM 5.0 Electric Only	0.87	1.10	1.02	1.05
No Persistence	1.19	1.16	1.02	0.97
No Persistence Electric Only	0.93	0.95	0.84	0.80

Even excluding gas savings (which, again, the IPA does not believe to be an appropriate methodology), the TRC results of the bundled programs using the TRM 5.0 methodology are all above 1.0. In addition, while the IPA does not consider Ameren Illinois' Cost of Supply test as a criterion for excluding programs from the Plan, the continuation option on its own, or bundled with any of the expansions, does not pass the Cost of Supply test.

Based on this analysis and Section 16-111.5B's directive that the IPA "shall include . . . energy efficiency programs and measures it determines are cost-effective" in its Plan,[260] the IPA recommends including the behavioral program continuation with expansion into all-electric homes. This raises the question of what level of expansion should be adopted: while TRC results are higher for the smaller expansion, all expansions pass the TRC. In the IPA's view, including the largest cost-effective expansion proposed by the bidder appears most consistent with Section 16-111.5B's requirement to "fully capture the potential for all achievable cost-effective savings, to the extent practicable,"[261] and the Agency thus includes that program. The IPA further

[259] The bidder stated in its bid that the expansion options "all assume that this existing program continues concurrently." A potential source of any lack of clarity regarding the components of the bid may lie in the confusing way in which the bidder structured its bid, as the expansions were listed as options 1 through 3, and the existing program as option 4.
[260] 220 ILCS 5/16-111.5B(a)(4).
[261] 220 ILCS 5/16-111.5B(a)(5).

notes that because all-electric homes inherently have higher electric bills than other homes, maximizing participation of those homes in an energy efficiency program is sensible.

9.5.5 Duplicative Programs

In the docket approving the Agency's 2014 Plan, significant consideration was given to how to address third-party program bids that may be "duplicative" of existing programs under Section 8-103 of the PUA. Based on prior years' Plans, the IPA understands the term "duplicative" to mean a program that overlaps an existing program in a manner in which greater market participation by vendors does not yield sufficient additional value to consumers. Alternatively, while a "competing" program may occupy the same general space, "competing" programs may benefit from multiple delivery channels. The general goal would be that "duplicative" programs are to be avoided, while "competing" programs would be acceptable to the extent that the competition does not render one or both non-cost-effective.

The review process approved by the Commission for analyzing "duplicative" or "competing" bids operates as follows:

- First, the utilities receive and review the third party RFP results, and determine which bids are, in the utility's estimation, duplicative or competing. The utilities are under no obligation to identify any programs in this manner.
- Next, in the annual July 15 assessment submitted to the IPA, the utility may exclude programs it has determined are duplicative or competing from the estimated savings calculation (and associated adjustments to the load forecast). However, in their submittals to the IPA, the utilities must: (1) describe the duplicative or competing program; (2) explain why the utility believes it is competing or duplicative; and (3) provide the IPA with all of the underlying documents as it would for any other bid.
- In preparing its annual procurement plan, the IPA independently reviews all of the bids submitted by the utilities and determines which bids the IPA believes are duplicative or competing. The IPA identifies all proposed programs to the Commission in its Procurement Plan filing, along with a recommendation on which, if any, programs should be excluded as duplicative or competing.
- After the Plan has been filed, the parties to the Procurement Plan approval litigation—including the IPA—may opine on whether a particular program is duplicative or competing, and the Commission will make the final determination. To the extent that a utility had previously determined that a program is duplicative or competing but the Commission disagrees, the utility will update the estimated energy savings and load forecast to reflect the readmission of the program.[262]

In addition to addressing the process for determining whether a program is "duplicative" or "competing," the Commission also approved a multi-factor inquiry to be employed in making such determinations:

> (1) similarity in product/service offered; (2) market segment targeted, including geographic, economic, and customer classes targeted; (3) program delivery approach; (4) compatibility with other programs (for instance, a program that created an incentive to accelerate the retirement of older inefficient appliances could clash with a different program that tunes-up older appliances); (5) likelihood of program success (a proven provider versus an undercapitalized or understaffed provider, if such evidence is placed in the record); (6) the effect(s) on utility joint program coordination, and (7) impact on Section 8-103 EEPS portfolio performance.[263]

[262] Docket No. 13-0546, Final Order dated December 18, 2013 at 149.
[263] Id.

Because Section 8-103 programs have not yet been approved by the Commission, no proposed Section 16-111.5B program can be considered "duplicative" of any existing Section 8-103 program. However, as previously explored by the Commission in Docket No. 14-0588, two proposed Section 16-111.5B programs may indeed be "duplicative" of one another based on application of the criteria above, thus forcing a clear choice between overlapping programs or some other corrective action intended to safeguard against the erosion of customer value.

For this year's Plan, the issue of duplicative programs arises when considering small business bids received in response to this year's RFP. Of the eight small business programs that passed the TRC, six of the programs had varying degrees of overlap in their offerings. Two other programs (Savings Through Efficient Products and New Construction) were determined by Ameren Illinois to be compatible with all other programs.

For the six programs that did have varying degrees of overlap, Ameren Illinois assessed the programs' scope and prior experience with the vendors to recommend that one of the programs (Small Business Whole Building) not be included. The remaining five bids (Small Business Direct Install, Private HVAC, Public HVAC, Exterior Lighting, and Lit Signage) were deemed sufficiently distinct such that they do not create issues of duplication. The Small Business Whole Building program overlaps all of these other programs, and in Ameren Illinois' assessment, including it along with the other programs would violate the duplicative test.

The IPA observes that an alternative approach could be to approve the Small Business Whole Building program, but not the other programs. This approach would have the added benefit of including measures to address refrigeration—something not included in the other bids. However, the IPA notes that Ameren Illinois has included some refrigeration measures in its Section 8-103 portfolio under consideration in Docket No. 16-0413 (which, if approved by the Commission, could mitigate this concern).

One perhaps important aspect of Ameren Illinois' proposal is its past experience with these bidders and the lower success rates of other programs from the bidder that offered the Small Business Whole Building program. As discussed further above and also in considering programs proposed by ComEd below, there may be valid reasons to take poor past program performance into account in evaluating proposals—and especially overlapping proposals for which some choice must be made.

While the IPA believes either approach would be workable, given that a decision between the two approaches must be made, the IPA believes Ameren Illinois' assessment of vendor performance offers value in making this determination and adopts Ameren Illinois' recommendation to exclude the "duplicative" Small Business Whole Building program.

The IPA also recognizes that in the Section 8-103 Plan under consideration in Docket No. 16-0413, Ameren Illinois has included a Small Business Direct Install program. As noted in the discussion of the Demand Based Ventilation Control in Section 9.5.4.2, because that program has not been approved by the Commission, the Small Business Direct Install program proposed under Section 16-111.5B cannot be considered "duplicative" of the Section 8-103 Small Business Direct Install program. To mitigate any such concerns, however, the Commission could consider offering only conditional approval of the Small Business Direct Install program in this Plan, contingent on the Small Business Direct Install program not being approved in Docket No. 16-0413, and with the rejection of the program proposed here contingent on Ameren Illinois (or other stakeholders) demonstrating that if the duplicative screening criteria were applied, the Section 16-111.5B program would in fact be duplicative of the Section 8-103 program.

The IPA further notes that one additional small business program (Deep Retrofit, which targets just gas stations and convenience stores) narrowly failed the TRC test. This program initially passed the TRC, but as discussed in footnote 246, when Ameren Illinois updated its methodology for including the future price of carbon, the results for this program fell just below the TRC to 0.98.

However, even with a positive TRC, Ameren Illinois determined that this program would duplicate measures in both the recommended Small Business Direct Install program as well as the not recommended Small Business Whole Building program. Ameren Illinois initially had recommended not including this program for similar reasons to why it did not recommend including the Small Business Whole Building program, but this "duplicative" determination was rendered moot by the subsequent negative TRC result. Should there be further updates resulting in this program passing the TRC test, for the reasons stated above for the Small Business Whole Building program, the IPA would accept Ameren Illinois' recommendation to consider the Deep Retrofit program as "duplicative" rather than simply not "cost-effective."[264]

9.5.6 Additional Conditions Requested by Ameren Illinois

Ameren Illinois raised additional issues with three programs and requested that additional conditions be applied to their approval.

- For the Residential Retail Lighting program, Ameren Illinois noted that LED prices are dropping, and therefore requested that since the bid was for three years, that "AIC should be granted the ability to reopen the contract on an annual basis to review product type, product quantity and price to ensure the customer is achieving a good value through the program."[265] Given the dynamic nature of the lighting market, this condition appears reasonable to the IPA.
- For the Community LED Distribution program which proposes to distribute LEDs through food pantries, Ameren Illinois raised concerns regarding the number of bulbs to be distributed per household (the program builds off a current year program which is distributing CFL bulbs), the relative newness (in Ameren Illinois service territory) of the distribution approach, and the ongoing reduction of prices for LED bulbs. Due to these concerns, Ameren Illinois requested that the program only be approved for one year (rather than three years as bid) to allow Ameren Illinois to assess the similar CFL distribution program currently underway. While the IPA appreciates Ameren Illinois' concern, an alternative approach could be to apply to this program a similar condition that is applied to the Residential Retail Lighting program, and it is unclear to the Agency how the pay-for-performance nature of Section 16-111.5B contracts would fail to safeguard ratepayers against any failures in these program design approaches.
- For the Low Income Multifamily program, Ameren Illinois notes that the vendor is currently supporting DCEO programs. The RFP includes a condition that "[i]f an IPA bidder later works under the AIC EE Plan as either a contractor or subcontractor, a clear separation of duties and costs will be required under the AIC contract." Ameren Illinois suggests extending that concept to encompass work for DCEO in order to prevent future unfair bidding advantages. While separation of duties appears to be a reasonable concept, the IPA notes that given the fact that DCEO does not have an approved future Section 8-103/8-104 portfolio, it is unknown at this time if this vendor will continue to be a DCEO contractor in the future.

9.5.7 Ameren Illinois Programs Recommended for Approval

Ameren Illinois' submittal includes identification of 10 energy efficiency offerings for this Procurement Plan with a TRC of above 1.0, which were not determined to be "duplicative," and which met the requirements of Ameren Illinois.[266] In reviewing the bids received by Ameren Illinois, the IPA determined that two additional programs should have been included, bringing the total of programs included in this Plan to 12. These programs are exhibited in Table 9-3.

[264] Perhaps further reinforcing a determination to exclude this program is that the vendor in question is the same vendor flagged in the ComEd performance risk discussion in Section 9.6.5 below.
[265] Ameren Illinois Section 16-111.5B Submittal at 28.
[266] Ameren Illinois also provided the results of the Utility Cost Test ("UCT") and all the proposed programs passed the UCT. As it has in prior years, the IPA considers that informational only and has not used the UCT test in its consideration of programs to include in this Plan.

Table 9-3: Ameren Illinois Energy Efficiency Offerings

Program	2017 -2018		2018 – 2019		2019 – 2020		TRC
	Net Savings (MWh)[267]	Total Utility Cost	Net Savings (MWh)	Total Utility Cost	Net Savings (MWh)	Total Utility Cost	
Community LED Distribution	12,210	$2,675,562	14,900	$2,675,562	17,177	$2,675,562	1.85
Residential Retail Lighting	92,773	$14,446,037	93,324	$14,487,428	93,807	$14,537,878	3.34
Low-Income Multifamily	6,092	$958,568	6,092	$955,165	6,092	$956,299	1.65
Small Business Direct Install	21,759	$5,711,937	21,488	$5,711,977	21,488	$5,751,932	1.18
STEP	1,967	$765,675	1,967	$765,675	1,967	$765,675	1.47
Private HVAC	6,957	$1,134,400	6,957	$1,134,400	6,957	$1,134,400	1.45
Public HVAC	6,957	$1,134,400	6,957	$1,134,400	6,957	$1,134,400	1.45
Exterior Lighting	8,346	$2,516,254	11,095	$3,345,367	13,316	$4,015,213	1.21
Lit Signage	12,978	$3,082,479	14,941	$3,544,850	17,923	$4,253,820	1.05
Commercial New Construction	978	$269,259	1,957	$546,939	-	$113,710	1.51
Behavioral Program (Continuation Plus 125k All-Electric Expansion)	16,254	$2,812,500	24,783	$3,048,750	31,191	$3,358,125	1.17
Demand Based Ventilation Control	2,901	$843,732	4,641	$843,732	4,061	$843,732	1.97

The total net savings for these programs is estimated as 190,172 MWh at the busbar for the 2017–2018 delivery year, 209,102 MWh for the 2018–2019 delivery year, and 220,936 MWh for the 2019–2020 delivery year. These programs also contribute to a peak reduction of approximately 13 MW. The estimated savings attributable to eligible retail customers is 71,008 MWh for the 2017–2018 delivery year, 72,315 MWh for the 2018–2019 delivery year, and 75,900 MWh for the 2019–2020 delivery year.

9.5.8 Ameren Illinois Reservations and Requested Determinations

In its filing, Ameren Illinois made the following reservations:

- "AIC reserves the right to update, revise, amend or end the programs approved in this docket. AIC's positions reflected herein are subject to change and AIC reserves the right to adjust any terms or conditions with any selected implementers to account for its upcoming Section 5/8-103 and Section 5/8-104 integrated energy efficiency and demand response Plan 4 filing, any pertinent ICC Orders, including those addressing customer data and privacy, or other relevant matters."[268]

While the IPA appreciates the challenges created in the timing lag between the approval of Section 16-111.5B programs in this Plan and the ongoing Section 8-103 and 8-104 proceeding, the Agency is concerned that bidders had a reasonable expectation that the provisions of the RFP would be applicable to the consideration of their bids, and after the fact changes could have a negative (or positive) impact on their desire to move forward and implement their proposed programs.

Ameren Illinois also made the following requests:

- "AIC seeks express approval that it is permitted to recover costs that exceed the estimated program costs. In no case will the costs to be recovered be greater than 110% of the estimated program costs

[267] MWh savings shown in Table 9-3 through Table 9-5 are at the busbar.
[268] Ameren Illinois Section 16-111.5B Submittal at 8.

plus administration costs. In lieu of this express approval, AIC will be forced to prematurely discontinue approved programs prior to the estimated budget being expended."[269]

- "AIC may seek approval of programs as part of its Section 5/8-103 and Section 5/8-104 Plan that would render certain programs to be approved as a part of the Procurement Plan duplicative, and may seek conditional findings in this docket to provide for such an outcome."[270]

As in previous years, the IPA does not object to the first request. However as noted in regard to the reservations made by Ameren Illinois, the IPA has concerns related to the second request. This request appears to be a request that changes the playing field for bidders after the fact through allowing a participating utility to receive bids under an open-ended RFP, but then to potentially shape its Section 8-103 portfolio so as to disqualify certain third-party bids after their receipt and analysis. It is unclear at this time how this reservation of rights will be applied by Ameren Illinois, but the Agency will approach any such post-hoc assertion of duplicity with an eye toward a request for proposal process that took place without any such overlapping programs having been identified to bidders.

In addition to adopting these determinations, the IPA requests that the ICC approve the incremental energy efficiency programs as described above.

9.6 ComEd

ComEd's submittal to the IPA prepared in compliance with Sections 16-111.5 and 16-111.5B of the PUA is included in Appendix C of this Plan, which may be found on the IPA's website posting of the 2017 Procurement Plan at www.illinois.gov/ipa. Please note that a document submitted by ComEd entitled "ComEd Third Party Efficiency Program Results of 2016 Bid Review, July 15, 2016" contains confidential data and, consistent with prior years' practice for confidential submittals, is not included with this Plan or otherwise publicly available.

The IPA believes that ComEd's filing meets the requirements of Section 16-111.5B(a)(1)-(3) and the programs listed in Table 9-5 should be approved pursuant to Section 16-111.5B(a)(5).

9.6.1 ComEd Managed Programs

As part of its assessment of energy efficiency programs, ComEd chose to include in its submittal three residential and two business programs that are continuations of existing ComEd managed programs. The programs include Home Energy Reports, Residential Lighting, Residential Upstream Pumping, Small Business Energy Services, and LED Streetlighting.

As the Agency understands it, this approach is intended in part to solve the challenge of how to "expand" 8-103 programs through the Section 16-111.5B process when the upcoming Section 8-103 portfolio has not yet been approved, a topic for which the Commission sought workshop consideration of solutions in Docket No. 15-0541 to inform the development of the 2017 Plan. By moving these programs wholesale into the Section 16-111.5B process, ComEd is able to run them at an "expanded" level that fully maximizes cost-effectiveness while filling out its Section 8-103 portfolio with other cost-effective programs. While distinct from Ameren Illinois' approach (which was to offer an open-ended RFP for any programs through Section 16-111.5B, subject to the conditions discussed above), the IPA is fully supportive of this approach (as was the Commission in previously approving a similar approach taken by ComEd in Docket No. 13-0546) and recommends the adoption of these ComEd Managed Programs as part of the 2017 Plan.

[269] Id. at 10.
[270] Id. at 10.

9.6.2 ComEd Bids Received

ComEd received 27 bids, with one bid withdrawn (a residential lighting program submitted "in error" by the bidder, per ComEd). All bids sought contracts of three years in length. The remaining 26 programs included four residential programs, 14 business programs, five public sector programs, and three low income programs. Of these programs, six failed the TRC,[271] one was duplicative of a ComEd offered program included as part of its Section 16-111.5B submittal (as referenced above, ComEd noticed to bidders in its RFP that certain programs would be run by ComEd and placed wholesale into the Section 16-111.5B portfolio so as to avoid the limitations of the Section 8-103, advising bidders not to bid on any such programs), and three were determined by ComEd to fail to meet minimum performance expectations and thus fit to be disqualified even if cost-effective. This left 16 programs for ComEd to recommend for inclusion in this plan. For two of these programs, that approval contained certain conditional provisions described below in Section 9.6.7.

The 27 bids received was a significant increase over the 17 bids received by ComEd in response to its Section 16-111.5B RFP for the 2016 Plan; given the three-year contract length offerings, this increase is perhaps not surprising. As with Ameren Illinois, ComEd posted its RFP to the AESP website, and also posted the RFP on Exelon's procurement portal (opening it for bids by registered vendors, and automatically notifying all vendors registered with Exelon of its release) and distributed a copy of the RFP (with instructions for vendor registration) to the SAG email distribution list.

While ComEd did not require surety bonds as was done by Ameren Illinois, ComEd has implemented a strict pay for performance model as a reaction to the implications of the disallowance of expenses from a prior Section 16-111.5B program whose vendor went bankrupt.[272] Because ComEd did not impose its revised model until after the close of the bid submittal deadline, the IPA has not had an opportunity to review whether the new requirements will adversely impact bidder participation in response to future ComEd RFPs.

In order to provide the IPA with a broad range of feedback on the bids received, ComEd solicited involvement from members of the SAG. The DCEO and two other organizations participated in the review process: the Natural Resources Defense Council and the Environmental Law & Policy Center. The Office of the Attorney General, the staff of the Illinois Commerce Commission, and the IPA also participated in the discussions but did not formally participate in the review process by providing bid scoring to ComEd. A key topic of discussion during the bid review was how to address programs that may pose a significant performance risk based on program design or the past performance of that bidder. These discussions resulted in the development of the two-part test for performance risk explained further below. The work product ultimately produced through this process was a report that was submitted to the IPA on a confidential basis that included qualitative program review by both stakeholders and ComEd.

9.6.3 Review of the ComEd TRC Analysis

ComEd uses the DSMore tool to conduct its TRC analysis. Unlike the BENCOST tool used by Ameren Illinois, DSMore uses proprietary analytical modules. ComEd provided detailed input and output tables from the analysis. While the IPA was able to review those fixed inputs and outputs, the IPA was not able to modify inputs to examine the impact on the outputs (thus limiting the sensitivity analysis that the Agency could conduct), a limiting feature of DSMore (at least relative to the flexibility offered by BENCOST) that the Agency also referenced in last year's plan.

[271] In comments received on the draft Plan, a bidder requested consideration of revised proposals for two of the programs that failed the TRC. The IPA has declined to adopt those revisions, noting that the revisions were proposed after the bidder was notified that the bids did not pass the TRC, and the revisions lowered the budgets, but not the MWh goals. This approach raises concerns about the accuracy of the bids. Even taking the lower budget and same MWh goals at face value (as opposed to having gone through the full internal ComEd review, stakeholder review, and IPA review), one of the programs still failed the TRC, and the other program only narrowly would have passed. The IPA does not believe the revised proposals should be considered.

[272] See generally Docket No. 14-0567.

For programs analyzed for the 2017 Plan, ComEd included an administrative adder of 9.6% in its TRC Test analysis—lower than the 11.5% estimate used last year.[273] This change resulted from the tracking of actual costs from the past two years, leading to a cost adder of 6.6% (as compared to the previous 8.5%) for program administration and the continuation of a 3% adder for evaluation.

As a manner of "stress testing" TRC results, ComEd also calculated TRC values without the inclusion of its administrative cost adder. One program (a public sector LED program) that did not pass the TRC (0.96) featured a positive TRC result (1.05) from removing the adder.[274] The other five programs that did not pass the TRC had values that ranged from 0.49 to 0.73 and the administrative adder was not a factor in their not passing.

9.6.4 Duplicative Program

As described in Section 9.5.5 above, a multi-step process has been used to consider if a proposed program is duplicative of an existing program. For the development of this Plan, the situation differs due to the lack of approved programs at the beginning for the three-year planning cycle. ComEd identified one bid for Advanced LEDs that it believes is duplicative of the SBES program that ComEd proposes offering and directly managing. The Advanced LED bid includes measures that are also offered by SBES, but it is a more limited offering and therefore creates a potential for lost opportunities (such as refrigeration) if customers participate in the Advanced LED program rather than the more comprehensive SBES program. While the IPA appreciates the potential additional customers that could be reached through this more targeted approach for advanced LEDs, it concurs with ComEd that this program is duplicative under the multi-factor inquiry described in Section 9.5.5 and should not be included in the Plan.

9.6.5 ComEd Identification of "Performance Risk"

In its review of programs for the 2016 Plan, ComEd flagged six programs as having a potential for performance/savings risk—programs for which there was some evidence that it could be challenging for the vendor to meet the energy savings goals proposed. However, ComEd did not recommend excluding any of those programs from the 2016 Plan; the IPA (and ultimately, the Commission) concurred, noting that the pay for performance model limited risks to ratepayers resulting from non-performance.

In its review of programs for the 2017 Plan, ComEd refined this issue to distinguish between "Performance Risk," as discussed in this section, and "Savings Risk," as discussed in Section 9.6.6. For the terminology utilized herein, performance risk is a more serious screen that could warrant the exclusion of programs from the Plan, while savings risk is less significant and not inherently a reason to consider exclusion of the program.

In bid review discussions around program proposals for the 2017 Plan, ComEd and stakeholders developed new screening criteria for programs that could have a significant likelihood of failing to achieve savings based on past performance. This screening was manifest as a two-part test: first, as a way to identify potential "performance risk" vendors, programs were screened to determine whether the bidder submitting the program failed to deliver five percent of their savings goals from prior Section 16-111.5B programs. If a vendor was identified as failing this test, the second screen applied was whether there was new information or a compelling reason that would suggest a different outcome for the proposed programs (e.g., new programs, new delivery approach, changes in team, or different market conditions). If the answer was "no" to both, then ComEd and stakeholders agreed the program posed a performance risk so significant that the program should not be recommended for inclusion.

[273] Prior to the Commission's Order in Docket No. 14-0588, ComEd had not included an administrative cost adder in its TRC analysis for Section 16-111.5B programs.

[274] Please note, however, that zeroing out administrative costs could be viewed as at odds with the Commission's Order in Docket No. 14-0588, which requires that the utilities track actual administrative costs incurred to inform Section 16-111.5B TRC analyses.

Four programs failed the five percent criteria. One of those four did not pass the TRC, rendering its performance risk screening irrelevant. For the remaining three programs (which targeted Schools/Colleges, Convenience Stores, and Demand Control Ventilation), all three programs were bid by the same vendor. A previous school direct install program offered by that vendor achieved 0% of its goal, while a similar demand control ventilation program achieved only 1.6% of its goal. The Convenience Store program proposal was substantially similar in program design to the Schools/Colleges program. ComEd and the stakeholders agreed there was not any other new information that would suggest a performance improvement, and therefore recommended the exclusion of these three programs.

The Agency is mindful of the potential for Section 16-111.5B as a driver of innovative program approaches from third-party vendors that may not have a foothold in the Section 8-103 portfolio development process, and is thus hesitant to embrace too strong a filter when such a filter would be used to mitigate relatively minor risks. Section 16-111.5B calls for this process to "fully capture all cost-effective energy efficiency, to the extent practicable," and while the Commission has determine that this language does allow it the flexibility to consider criteria other than cost-effectiveness, the clear mandate to "fully capture all cost-effective energy efficiency" informs that such discretion should be very carefully and thoughtfully applied.

At the same time, while the IPA believes that risks associated with non-performance are almost entirely mitigated through pay-for-performance contracting, there are other negative outcomes caused by non-performance which may justify being mindful of performance risk.[275] The two-step approach proposed as part of ComEd's submittal seeks to punish only those vendors performing especially poorly, and even then provides a second step examination that could allow for the inclusion of that vendor's program. It seeks not to punish unfamiliar or unorthodox program design, only egregious non-performance.

With those considerations in mind, the Agency believes this two-step approach developed by ComEd and participating stakeholders strikes a reasonable balance between competing considerations and agrees with its application to these programs. As such, the IPA is not including these three programs pursuant to the recommendation of ComEd.. Should some (or all) of these programs be recommended for inclusion in the Final 2017 Plan, Table 9-4 includes the savings and budgets for these programs.

Table 9-4: Performance Risk Programs

Program	2017 -2018		2018 – 2019		2019 – 2020		TRC
	Net Savings (MWh)	Total Utility Cost	Net Savings (MWh)	Total Utility Cost	Net Savings (MWh)	Total Utility Cost	
Schools/Colleges	2,632	$624,993	4,211	$999,989	3,685	$874,990	2.04
Convenience Stores	5,573	$1,249,941	8,918	$1,999,906	7,803	$1,749,917	1.22
Demand Control Ventilation	4,203	$999,979	6,725	$1,599,967	5,884	$1,399,971	3.57

9.6.6 ComEd Identification of "Savings Risk"

ComEd and stakeholders also identified four other programs as having some risk of not meeting savings goals, but not at the level of concern of the programs flagged for a performance risk as described above. ComEd did not recommend excluding these programs, but raised the issue for potential consideration by the IPA and/or the Commission. These four programs are discussed below:

- One program (Small Business Monitoring-Based Commissioning) also did not pass the TRC test, rendering the savings risk issue moot.

[275] These outcomes include administrative costs borne through the rider to manage contracts associated with non-performing programs and market dilution from especially poorly designed programs.

- A program that targets faith-based institutions has a small staff and has experienced turnover in key personnel, raising concerns related to whether the vendor has sufficient resources to implement the program.
- The Energy Saver program is a free opt-in online rewards program to incent energy efficiency in residential households. The program has been in operation for a number of years and has consistently failed to meet its savings goals.
- The Small Business New Construction program has long lead times to develop and construct buildings (and therefore generate savings). Due to the pay for performance contracting structure, this could provide financial challenges to the vendor. This program is also one that is flagged in Section 9.6.7 below for receiving only a conditional approval.

The IPA has reviewed these concerns. While it appreciates the savings risks that could exist for these programs, the Agency believes that these risks are sufficiently mitigated by the pay for performance contracting model and therefore does not propose to exclude these programs from the Plan.

9.6.7 Conditional Approvals

One bid for a program to assist Assisted Living Centers was offered by a vendor who currently manages aspects of ComEd's SBES program. Because that management responsibility includes managing trade allies, ComEd is concerned that also serving as a vendor under Section 16-111.5B would present a potential conflict of interest given the differing incentive levels between programs.

Because ComEd will be putting out for bid the future management of the SBES program, the current manager is not necessarily going to be the future manager. Should the current manager (i.e., bidder) be awarded the next management contract, that entity has indicated that they would prefer that management role over just the Assisted Living Center program (if the two are mutually exclusive). ComEd thus requested conditional approval of the Assisted Living Center program such that if the vendor is awarded the SBES contract, it will not proceed with the Assisted Living Center program. The IPA agrees with that conditional approval.

A bid for Small Business New Construction program is potentially duplicative of a program that ComEd plans to propose as part of its Section 8-103 energy efficiency portfolio later this year. Because the Section 8-103 portfolio has not yet been approved by the Commission, ComEd has requested that the approval for the Small Business New Construction bid be only conditionally approved.

Specifically, ComEd has suggested that if the Commission does not approve the similar program in ComEd's Section 8-103 portfolio, then the Small Business New Construction program would proceed; otherwise, the approval of the Section 8-103 program would authorize ComEd not to proceed with this program under Section 16-111.5B. Currently, the Small Business New Construction program is included in this Plan because it meets the requirements for consideration of Section 16-111.5B programs. However, if the Commission wishes to approve it on a conditional basis pending the outcome of the approval ComEd's Section 8-103 portfolio, the IPA would not object to that determination.

9.6.8 ComEd Programs Recommended for Approval

ComEd's submittal includes identification of 21 energy efficiency programs for inclusion in this Procurement Plan (five ComEd managed, and 16 third-party administered). All of these programs passed the TRC test at the time of assessment.[276] These programs are exhibited in Table 9-5.

[276] ComEd also provided the results of the UCT test and 14 of the 16 proposed programs passed the UCT. As it has in prior years, the IPA considers that informational only and has not used the UCT test in its consideration of programs to include in this Plan.

Table 9-5: ComEd Energy Efficiency Offerings

Program	2017 -2018		2018 – 2019		2019 – 2020		TRC
	Net Savings (MWh)	Total Utility Cost	Net Savings (MWh)	Total Utility Cost	Net Savings (MWh)	Total Utility Cost	
Residential Lighting*	217,863	$38,187,475	210,503	$38,191,850	201,959	$38,196,334	8.34
Residential Behavior*	321,958	$11,283,750	57,952	$11,290,844	55,506	$11,298,115	1.53
Residential Upstream Pumping*	642	$1,200,000	1,285	$1,800,000	2,312	$2,760,000	1.03
Small Business Energy Savings*	190,953	$47,457,500	209,819	$52,191,438	230,912	$57,395,473	1.45
LED Street Lighting*	4,153	$2,459,250	6,056	$3,586,406	6,308	$3,735,191	12.56
Small Commercial Lit Signage	19,989	$4,530,767	24,430	$5,538,748	27,752	$6,294,280	1.24
School Direct Install	4,039	$1,298,639	3,072	$1,116,897	3,072	$1,122,488	1.90
Agricultural Energy Efficiency	2,330	$627,209	3,014	$789,380	3,532	$921,494	1.27
Senior and Assisted Living	22,518	$4,609,096	22,518	$4,609,096	22,518	$4,609,096	1.19
Faith-Based	1,149	$389,681	1,149	$389,681	1,149	$378,652	2.57
Rural Kits	1,241	$591,690	1,241	$591,690	1,241	$591,690	2.71
AC Tune Up	20,326	$4,190,893	20,326	$4,246,219	20,326	$4,303,412	1.51
New Construction Service Small Buildings	289	$87,857	1,851	$563,081	2,362	$718,279	3.23
Energy Saver	5,456	$240,786	6,894	$304,290	8,333	$367,794	1.52
Moderate Income Kits	11,645	$1,994,400	11,645	$1,994,400	11,645	$1,994,400	4.91
Middle School Energy Education Campaign	2,861	$1,139,356	2,861	$1,214,356	2,861	$1,214,358	1.78
Savings Through Efficient Products	2,397	$795,381	2,397	$829,791	2,397	$865,907	1.94
Enhanced Building Optimization	13,102	$2,500,000	13,102	$2,500,000	13,102	$2,500,000	1.92
LED Distribution	15,996	$3,056,000	12,997	$2,483,000	9,998	$1,910,000	1.80
Low Income Kits	22,048	$6,156,372	22,048	$6,156,372	22,048	$6,156,372	1.97
Low Income Multifamily Retrofits	6,313	$2,558,683	6,313	$2,558,683	6,313	$2,558,684	1.65

* ComEd Managed Programs.

The total net savings for these programs is estimated as 887,268 MWh at the busbar for the 2017–2018 delivery year, 641,473 MWh for the 2018–2019 delivery year, and 655,646 MWh for the 2019–2020 delivery year. The programs also contribute to a peak reduction of approximately 41 MW. The estimated savings attributable to eligible retail customers is 493,196 MWh for the 2017–2018 delivery year, 329,546 MWh for the 2018–2019 delivery year, and 331,957 MWh for the 2019–2020 delivery year.

The IPA agrees with this assessment and requests that the Commission approve the incremental energy efficiency programs as described above.

9.7 MidAmerican

Section 16-111.5B of the Public Utilities Act calls for each utility that participates in the procurement planning process set forth in Section 16-111.5 to include additional information related to energy efficiency.[277] However, as discussed in the 2016 Plan, Section 16-111.5B's compliance "requirements" include requiring that a utility submit its "most recent analysis submitted pursuant to Section 8-103A of this Act and approved by the Commission under subsection (f) of Section 8-103 of this Act,"[278] the "[i]dentification of new or expanded cost-effective energy efficiency programs or measures that are incremental to those included in energy efficiency and demand-response plans approved by the Commission pursuant to Section 8-103 of this Act,"[279] and a requirement to "develop requests for proposals consistent with the manner in which it develops requests for proposals under plans approved pursuant to Section 8-103 of this Act."[280] These requirements are seemingly of limited applicability to MidAmerican, given that Section 8-103 of the Public Utilities Act expressly "does not apply to an electric utility that on December 31, 2005 provided electric service to fewer than 100,000 customers in Illinois"[281]—such as MidAmerican.[282]

In its initial Section 16-111.5B submittal offered on July 15, 2015, MidAmerican provided information related to the discrete requirements of Section 16-111.5B(a)(3)(A)-(G) to the extent such requirements could be applicable to it, but did not identify new or expanded energy efficiency programs that could be included in an IPA Procurement Plan. Given the apparent inapplicability of many of Section 16-111.5B's provisions to MidAmerican, the Agency concluded that this approach was acceptable. Upon review, the Commission agreed with MidAmerican and the Agency, finding that Section 8-103 indeed does not apply to MidAmerican and agreeing that because MidAmerican's submittal "provides substantive responses and accompanying information where appropriate," it meets MidAmerican's requirements under Section 16-111.5B.[283]

For the 2017 Plan, MidAmerican has provided the Agency with an incremental energy efficiency submittal similar in scope and substance to that which it submitted for the 2016 Plan. This submittal contains relevant information where appropriate and a brief statement as to the inapplicability of a Section 16-111.5B provision where it is not. In light of the Commission's Order in Docket No. 15-0541 and the Agency's corresponding interpretation of Section 16-111.5B, the IPA believes that MidAmerican's July 15, 2016 submittal meets the requirements of Section 16-111.5B as it applies to that utility.

As those requirements as applied to MidAmerican do not include the identification of incremental energy efficiency programs for inclusion in the IPA's annual procurement plan, no such programs have been analyzed or are recommended for inclusion in the 2017 Plan.

[277] 220 ILCS 5/16-111.5B(a) ("Beginning in 2012, procurement plans prepared pursuant to Section 16-111.5 of this Act shall be subject to the following additional requirements…").
[278] 220 ILCS 5/16-111.5B(a)(3)(B).
[279] 220 ILCS 5/16-111.5B(a)(3)(C).
[280] 220 ILCS 5/16-111.5B(a)(3).
[281] 220 ILCS 5/8-103(h); see also Docket No. 15-0541, Final Order dated December 16, 2015 at 68.
[282] Instead, MidAmerican is governed by Section 8-408 of the Public Utilities Act, and its last five-year energy efficiency plan filed pursuant to those provisions was approved by the Commission in December 2013. See generally Docket Nos. 13-0423 and 13-0424 (consol.), Final Order dated December 18, 2013.
[283] Docket No. 15-0541, Final Order dated December 16, 2015 at 69.

10 Procurement Process Design

The procedural requirements for the procurement process are detailed in the Illinois Public Utilities Act at Section 16-111.5.[284] The Procurement Administrator, retained by the IPA in accordance with 20 ILCS 3855/1-75(a)(2), conducts the 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 Bid Participation Fees and Supplier Fees which are assessed by the IPA. 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.

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[285], provide supply requirements, and otherwise explain the competitive procurement process. In addition to such other publication as the procurement administrator determines is appropriate, this information shall be posted on the Illinois Power Agency's and the Commission's websites. The procurement administrator shall also administer the prequalification process, including evaluation of credit 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*

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

[285] The 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.

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.

10.1 Contract Forms

The IPA believes that the forms have now become largely standardized and should remain acceptable to future potential bidders. As was the case with the 2014, 2015 and 2016 procurement events, 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 2017 Procurement Plan would be the eleventh iteration of IPA-run procurement events, when including the Spring 2016 procurement events,[286] the March 31, 2016 Supplemental Photovoltaic Procurement, the June 23 summer procurement of RECs from distributed generation, and the planned Fall 2016 procurement events for the procurement of capacity for Ameren Illinois and the procurement of standard energy products for all of the utilities. 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. In the 2014, 2015 and 2016 procurement events, potential bidders submitted only limited comments on the proposed changes to the forms.

In the procurement events conducted for energy blocks and RECs since 2012 (the Rate Stability Procurement and the standard Spring Procurement including the RPS Procurement) 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 and RECs procurement events were similar to the Ameren Illinois contract documents.

[286] The Spring 2016 procurement events include: the April 25 procurement of standard energy blocks and the May 4 procurement of RECs

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 last used forms, namely the energy, capacity and RPS contracts used in the 2016 procurement events be the starting point for the contracts used in the energy, capacity, REC 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.

10.2 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."[287] Additionally in April, 2014 the IPA adopted new 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.[288]

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 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 get the 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 is the IPA's and not the utility's. The incentives for suppliers to pay the Supplier Fees were reduced as a result.

The IPA 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

[287] 20 ILCS 3855/1-75(h).
[288] 83 Ill. Admin. Code. 1200.110, 1200.220.

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 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 in the 2014, 2015 and 2016 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 Part 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, capacity and non-DG REC 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.

10.3 Second Procurement Event

The IPA recommends that procurement events be held in the spring and fall of 2017 for purchase of energy blocks, capacity and RECs under the 2017 Procurement Plan, and two procurements of DG REC be held at dates to be determined. The components of the energy and RECs procurement process detailed above would be conducted in the spring event. For the fall procurement event, 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 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 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 procurement event will have access to an abbreviated qualification and registration process if they also participate in the fall procurement event;

The IPA recommends that the fall procurement event includes the procurement of standard energy products for MidAmerican, Ameren Illinois and ComEd as well as a portion of the Ameren Illinois capacity requirements.

10.4 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 23, 2016 the ICC Staff posted a public notice for the informal hearing for the purpose of receiving comments regarding on the procurement process for the procurement events that were held during the summer and fall of 2015 and the spring of 2016. The Summer 2015 event involved the initial procurement of SRECs under the provisions of new Section 1-56(i) of the IPA Act and the Agency's resulting supplemental photovoltaic procurement plan. The Fall 2015 procurements involved the procurement of standard energy products to meet the requirements of ComEd's and Ameren Illinois's eligible retail customers for November 2015 through May 2016, MISO Zonal Resource Credits capacity products for Ameren Illinois, distributed generation RECs for ComEd and Ameren Illinois, and SRECs under the Supplemental Photovoltaic Procurement Plan. The Spring 2016 procurement events included the purchase of a portion of the three utilities' energy requirements to meet eligible retail customers' needs for the 2016-2017, 2017-2018, and 2018-2019 delivery years, as well as the purchase of RECs for ComEd, MidAmerican and Ameren Illinois, the procurement of SRECs for each utility, and the purchase of RECs from wind generation for MidAmerican.

Initial comments, which were due to the Commission by June 30, 2016, were received from Boston Pacific Company, Inc. ("Boston Pacific").[289] No reply comments were received. Boston Pacific's comments included a summary of the results of the procurement events held between Summer 2015 and Spring 2016, provided recommendations for consideration regarding the DG procurement process, and noted that the current locational preference for REC procurements may result in higher costs for Illinois ratepayers.[290] Boston Pacific's recommendations regarding the DG procurement process were focused on improving bidder response to the DG RFP including: allowing bidders to offer speculative RECs, reducing credit requirements and supplier fees, switching to unit-specific contracts, and ensuring that bidders have sufficient lead time to develop DG systems. Boston Pacific also commented that the priority provided to RECs bid from sources in Illinois and the Adjoining States[291] established under the Illinois Power Agency Act has resulted in higher RECs costs relative to RECs procured from other states.

Comments received in the informal hearing process are available on the Commission's website.

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[289] Boston Pacific serves as the Commission's procurement monitor.

[290] "Initial Comments on the Summer 2015 through Spring 2016 Electric Procurement Events Pursuant to Section 16-111.5(o) of the Illinois Public Utilities Act," Presented to the Illinois Commerce Commission by Boston Pacific Company, Inc. June 30, 2016.

[291] The Adjoining States include: Missouri, Iowa, Wisconsin, Michigan, Indiana, and Kentucky.

Appendices

Appendices are available separately at:

www2.illinois.gov/ipa/Pages/Plans_Under_Development.aspx

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

Appendix A. Regulatory Compliance Index

Appendix B. Ameren Illinois Submittal

- Ameren Illinois Letter Transmitting Final Data
- Ameren Illinois Forecasting Methodology
- Electric Energy Efficiency Submission in Accordance with 220 ILCS 5/16-111.5B
    - Appendix 1: Section 16.111.5B
    - Appendix 2: NTG Recommendations
    - Appendix 3: Ameren Illinois Third Party RFP
    - Appendix 4: Bidder Confirmations (marked "Confidential")
    - Appendix 5: Bidder Program Descriptions
    - Appendix 6: Detailed Bid Analysis (marked "Confidential")
    - Ameren Illinois 2016 Potential Study
        - Volume 1: Executive Summary
        - Volume 2: Market Research
        - Volume 3: Analysis
        - Volume 4: Appendices

Appendix C. ComEd Submittal

- ComEd Load Forecast for Five-Year Planning Period Jun 2017 – May 2022
- ComEd 2016 Third Party Efficiency Program Results of 2016 Bid Review (marked "Confidential")
    - Appendix C-1: Potential Study
    - Appendix C-2: Energy Efficiency Analysis Summary
    - Appendix C-3: PY9 Budget Shifts
    - Appendix C-4: Program Summaries
    - Appendix C-5: DSMore Model Inputs

Appendix D. MidAmerican Submittal

- IPA Letter Transmitting Final Data and Methodology
- Election to Procure Power and Energy for a Portion of its Eligible Illinois Retail Customers
    - MidAmerican Potential Study
    - Appendix A3: MidAmerican Measures
    - Assessment of Energy and Capacity Savings Potential in Iowa: Appendices (Attachments 1 and 2)
- Methodology For Illinois Electric Customers and Sales Forecasts: 2016-2025

Appendix E. Ameren Illinois Load Forecast and Supply Portfolio by Scenario

E.1 Total Delivery Service Area Load

- Table E-1 Ameren Illinois Delivery Service Area Load Forecast – Expected Case with Incremental Energy Efficiency
- Table E-2 Ameren Illinois Delivery Service Area Load Forecast – Expected Case (No Incremental Energy Efficiency)
- Table E-3 Ameren Illinois Delivery Service Area Load Forecast – High Case
- Table E-4 Ameren Illinois Delivery Service Area Load Forecast – Low Case

E.2 Ameren Illinois Bundled Service Load Forecast

- Table E-5 Ameren Illinois Bundled Service Load Forecast – Expected Case with Incremental Energy Efficiency
- Table E-6 Ameren Illinois Bundled Service Load Forecast – Expected Case (No Incremental Energy Efficiency)
- Table E-7 Ameren Illinois Bundled Service Load Forecast – High Case
- Table E-8 Ameren Illinois Bundled Service Load Forecast – Low Case

E.3 Ameren Illinois Peak/ Off Peak Distribution of Energy and Average Load

- Table E-9 Ameren Illinois Peak/Off peak Distribution of Energy and Average Load – Expected Case with Incremental Energy Efficiency
- Table E-10 Ameren Illinois Peak/Off Peak Distribution of Energy and Average Load – Expected Case (No Incremental Energy Efficiency)
- Table E-11 Ameren Illinois Peak/Off Peak Distribution of Energy and Average Load – High Case
- Table E-12 Ameren Illinois Peak/Off Peak Distribution of Energy and Average Load – Low Case

E.4 Ameren Illinois Net Peak Position by Scenario

- Table E-13 Ameren Illinois Net Peak Position – Expected Case with Incremental Energy Efficiency
- Table E-14 Ameren Illinois Net Peak Position – Expected Case (No Incremental Energy Efficiency)
- Table E-15 Ameren Illinois Net Peak Position – High Case
- Table E-16 Ameren Illinois Net Peak Position – Low Case

E.5 Ameren Illinois Net Off-Peak Position by Scenario

- Table E-17 Ameren Illinois Net Off Peak Position – Expected Case with Incremental Energy Efficiency
- Table E-18 Ameren Illinois Net Off Peak Position – Expected Case (No Incremental Energy Efficiency)
- Table E-19 Ameren Illinois Net Off Peak Position – High Case
- Table E-20 Ameren Illinois Net Off Peak Position – Low Case

Appendix F. ComEd Load Forecast and Supply Portfolio by Scenario

F.1 ComEd Residential Bundled Service Load Forecast

- Table F-1 ComEd Residential Bundled Service Load Forecast – Expected Case
- Table F-2 ComEd Residential Bundled Service Load Forecast – High Case
- Table F-3 ComEd Residential Bundled Service Load Forecast – Low Case

F.2 ComEd Commercial Bundled Service Load Forecast

- Table F-4 ComEd Commercial Bundled Service Load Forecast – Expected Case
- Table F-5 ComEd Commercial Bundled Service Load Forecast – High Case
- Table F-6 ComEd Commercial Bundled Service Load Forecast – Low Case

F.3 Peak/Off Peak Distribution of Energy and Average Load

- Table F-7 ComEd Peak/Off Peak Distribution of Energy and Average Load – Expected Case