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POWER AGENCY

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ELECTRICITY PROCUREMENT PLAN

Draft Plan for Public Comments

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Illinois Power Agency

2016 Electricity Procurement Plan

Prepared in accordance with the

Illinois Power Agency and Illinois Public Utilities Acts

Draft Plan for Public Comments

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1 Executive Summary

This is the eighth electricity and renewable resource procurement plan (the "Plan," "Procurement Plan," or "2016 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 as further regulated by 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 from 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 for the first time in an IPA Procurement Plan, MidAmerican Energy ("MidAmerican"). 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 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 2016-2017 energy delivery year and lasts through the 2020-2021 delivery year.

The 2015 Procurement Plan was approved by the Commission in Docket No. 14-0588. The Agency's 2015 Plan, as approved by the Commission called for continuing the use (first adopted in 2014) of two energy procurement events each year, to be held in the spring and fall. The 2015 Plan called at least 50% of Ameren Illinois' capacity requirements be procured in a fall procurement event. Finally, the 2015 Plan called for procurements of Solar Renewable Energy Credits ("SRECs"), and a procurement or Renewable Energy Credits from distributed generation devices.

The 2016 Procurement Plan recommends that the energy and renewable resources requirements for Ameren Illinois, ComEd, and MidAmerican be procured by the IPA through two block energy procurements (spring and fall), a spring renewables procurement, and a fall distributed generation procurement. In addition, the Plan calls for capacity procurements for Ameren Illinois and MidAmerican to be held as a Fall 2016 procurement event. The IPA recommends a minor change to the energy hedging strategy in which the October requirements will be hedged to 75% in the spring procurement and to 100% in the fall procurement event. The IPA also recommends that the load forecasts prepared by Ameren Illinois, ComEd and MidAmerican, which form the basis for the 2016 Plan, be adopted by the Commission.

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. While the IPA again this year investigated alternative risk management strategies, the IPA believes the continuation of its previous (tested and proven) risk management strategy is the most prudent, most reasonable, and the 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."[1]

The proposed hedging strategy, in the short term (prompt delivery year), is designed to manage the risk of load uncertainty resulting from the possibility of large blocks of load returning to the utilities because of municipalities choosing not to continue their aggregation programs.[2] As described in detail in Chapter 7, based on the analysis of the costs of procurement in Chapter 6 and supply shortfalls identified in Chapter 4,

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

[2] The largest single block of load that could return, customers in the City of Chicago, is returning during the late summer/early fall of 2015 and thus is already accounted for in the 2016 Plan.

the IPA recommends a refinement of the procurement approach adopted in the 2015 Plan for use in the procurement of power for delivery year 2016-2017 and beyond.

Consistent with the 2015 Plan, the IPA also continues to recommend procurement of energy in blocks of 25MW. The risk management strategy will continue 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 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 recommends that the Commission pre-approve a fall energy procurement event, which would 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 the 2015 Plan and years prior, the IPA 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, for this Plan, recommends the procurement of half of these volumes in the spring 2016 procurement event and the balance in the fall 2016 procurement event.

Additionally, for Ameren Illinois, the IPA recommends purchasing capacity in bilateral procurement events to satisfy a portion of the capacity requirements for the second and third delivery years. For MidAmerican, the IPA recommends purchasing all of the forecast capacity shortfall for the first delivery year (2016-2017) in the MISO capacity auction, which is known as the Planning Resource Auction ("PRA")[3]. For the following five delivery years (June 2017 through May 2022), the IPA recommends purchasing all of MidAmerican's forecast capacity shortfall in a bilateral procurement event in the fall of 2016 based on MidAmerican's July 2016 load forecast which will be pre-approved by the ICC in this docket, subject to the review of the IPA and the consensus among the IPA, ICC Staff, MidAmerican and the Procurement Monitor. The IPA recommends consensus because the capacity requirements for the 2021-2022 delivery year will not be known until MidAmerican produces the July 2016 load forecast.

Aside from the proposal 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 procurement and hedging strategy:

Table 1-1: Summary of Energy Hedging Strategy

Spring 2016 Procurement			Fall 2016 Procurement		
June 2016-May 2017 (Upcoming Delivery Year)	**Upcoming Delivery Year+1**	**Upcoming Delivery Year+2**	**October 2016-May 2017**	**Upcoming Delivery Year + 1**	**Upcoming Delivery Year + 2**
June 100% peak and off peak July and Aug. 106% peak, 100% off peak and Sep. 100% peak and off peak Oct. - May 75% peak and off peak	25%	12.5%	100%	25%	12.5%

[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.

Table 1-2: Summary of Capacity Procurement Strategy for ComEd

June 2016-May 2017 (Upcoming Delivery Year)	June 2017-May 2018	June 2018-May 2019
100% PJM RPM Auctions*	100% PJM RPM Auctions*	100% PJM RPM Auctions

* PJM RPM Base Residual Auctions for 2016-17 and 2017-18 have already cleared. PJM's initial Capacity Performance Resource auction will be completed by mid-September 2015.

Table 1-3: Summary of Capacity Hedging Strategy for Ameren Illinois

June 2016-May 2017 (Upcoming Delivery Year)	June 2017-May 2018	June 2018-May 2019
50% RFP in Sep. 2015 50% MISO PRA*	25% RFP in Sep. 2015 50% RFP in Fall 2016 25% MISO PRA**	25% RFP in Fall 2016 50% RFP in Fall 2017 25% MISO PRA***

* MISO Auction is expected to clear in April 2016.
** MISO Auction is expected to clear in April 2017.
***MISO Auction is expected to clear in April 2018.

Table 1-4: Summary of Capacity Hedging Strategy for MidAmerican

June 2016-May 2017 (Upcoming Delivery Year)	June 2017-May 2022
100% MISO PRA*	100% RFP in Fall 2016

* MISO Auction is expected to clear in April 2016.

1.2 Renewable Energy Resources

The load forecasts provided by the utilities on July 15, 2015 indicate that existing renewable energy resources under contract for Ameren Illinois and ComEd do not meet or exceed the Renewable Portfolio Standard obligations for solar photovoltaics or for distributed generation. MidAmerican has not previously been a part of the IPA procurement process, or subject to its provisions, and thus it does not have any resources previously procured to meet its overall obligations or its specific obligations for wind, photovoltaics, or distributed generation. Accordingly, the IPA recommends conducting a spring procurement event for general RECs (MidAmerican only), wind (MidAmerican only), and solar RECs (all utilities) using the Renewable Resources Budget. The IPA also proposes a fall procurement for distributed generation RECs using hourly ACP funds for Ameren Illinois and ComEd, and using the Renewable Resources Budget for MidAmerican.

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

Table 1-5: Summary of Procurement Plan Recommendations Based on July 15, 2015 Utility Load Forecast (Quantities to be Adjusted Based on the March and July 2016 Load Forecast):

	Delivery Year	Energy	Capacity	Renewable Resources	Ancillary Services
AMEREN ILLINOIS	**2016-2017**	Up to 675MW forecasted requirement (Spring Procurement) Up to 250MW additional forecasted requirement (Fall Procurement)	50% RFP in Sep. 2015 50% MISO PRA	One-year SRECs procurement up to 34.2GWh Five-year DG REC procurement up to 7.8GWh* No RPS procurement or sales for other resources, target exceeded	Will be purchased from MISO
	2017-2018	Up to 150MW forecasted requirement (Spring Procurement) Up to 125MW forecasted requirement (Fall Procurement)	25% RFP in Sep. 2015 50% RFP in Fall 2016 25% MISO PRA	No RPS procurement: shortage of 52.8 GWh, revisit next year	Will be purchased from MISO
	2018-2019	Up to 125MW forecasted requirement (Spring Procurement) Up to 150MW forecasted requirement (Fall Procurement)	25% RFP in Fall 2016 50% RFP in Fall 2017 25% MISO PRA	No RPS procurement: shortage of 413.4GWh, revisit next year	Will be purchased from MISO
	2019-2020	No energy procurement required	No further action at this time	No RPS procurement: shortage of 522.7GWh, revisit next year	Will be purchased from MISO
	2020-2021	No energy procurement required	No further action at this time.	No RPS procurement: shortage of 633.1GWh, revisit next year	Will be purchased from MISO
COMED	**2016-2017**	Up to 1,925MW forecasted requirement (Spring Procurement) Up to 725MW additional forecasted requirement (Fall Procurement)	100% PJM RPM Auctions	One-year SRECs procurement up to 69.9GWh Five- year DG REC procurement up to 16.3GWh* Total renewables are 68GWh short of target	Will be purchased from PJM
	2017-2018	Up to 475MW forecasted requirement (Spring Procurement) Up to 475MW forecasted requirement (Fall Procurement)	100% PJM RPM Auctions	No RPS procurement: shortage of 827.7GWh, revisit next year	Will be purchased from PJM
	2018-2019	Up to 450 MW forecasted requirement (Spring Procurement) Up to 425MW forecasted requirement (Fall Procurement)	100% PJM RPM Auctions	No RPS procurement: shortage of 1,616.6GWh, revisit next year	Will be purchased from PJM
	2019-2020	No energy procurement required	No further action at this time	No RPS procurement: shortage of 2,182.4GWh, revisit next year	Will be purchased from PJM
	2020-2021	No energy procurement required	No further action at this time	No RPS procurement: shortage of 2,527.7GWh, revisit next year	Will be purchased from PJM

MIDAMERICAN	**2016-2017**	Up to 100MW forecasted requirement (Spring Procurement) Up to 75MW additional forecasted requirement (Fall Procurement)	100% MISO PRA	One-year SRECs procurement up to 13.2GWh Five- year DG REC procurement up to 2.2GWh Total renewables are 220.4GWh short of target. Includes 165.3GWh of wind, 13.2GWh of solar and 2.2GWh of DG	Will be purchased from MISO
	2017-2018	No energy procurement required	100% RFP in Fall 2016**	No RPS procurement: shortage of 258.9GWh, revisit next year	Will be purchased from MISO
	2018-2019	No energy procurement required	100% RFP in Fall 2016**	No RPS procurement: shortage of 289.3GWh, revisit next year	Will be purchased from MISO
	2019-2020	No energy procurement required	100% RFP in Fall 2016**	No RPS procurement: shortage of 320.5GWh, revisit next year	Will be purchased from MISO
	2020-2021	No energy procurement required	100% RFP in Fall 2016**	No RPS procurement: shortage of 351.9GWh, revisit next year	Will be purchased from MISO

*The total DG RECs to be procured will be adjusted based on the results of the Fall 2015 DG procurement event.
** The fall 2016 capacity procurement will cover five planning years, starting with the 2017-18 Planning Year and ending with the 2021-2022 Planning Year.

1.3 Incremental Energy Efficiency

This plan is the fourth year for inclusion of incremental energy efficiency programs pursuant to Section 16-111.5B of the Public Utilities Act. The IPA recommends inclusion of the programs submitted by the utilities that have passed the Total Resource Cost and have not been determined to be duplicative of other programs.

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 2015.
2. Require the utilities to provide an updated load forecast by March 15, 2016 which will be pre-approved by the ICC as part of the approval of this Plan, subject to the review of the IPA. The consensus of each utility, the IPA, the ICC Staff, and the Procurement Monitor will be required if a utility load forecast triggers the curtailment of the Long-Term Power Purchase Agreements.
3. Approve two energy procurement events scheduled for spring 2016 and fall 2016. The energy amounts to be procured in spring will be based on the updated March 2016 load forecast and in accordance with the hedging levels stated in this Plan and as ultimately approved by the ICC as part of the approval of this Plan. The energy amounts (and capacity for Ameren Illinois and MidAmerican) to be procured in the fall will be based on the July 2016 expected load forecast developed by each of Ameren Illinois, MidAmerican and ComEd, and subject to the review of the IPA.
4. Approve procurement by ComEd, Ameren Illinois, and MidAmerican of capacity, network transmission service and ancillary services from their respective RTO for the 2016-2017 delivery year.
5. Approve a fall capacity procurement for Ameren Illinois in a quantity of 50% of its forecast requirements for the second delivery year (2017-2018) and 25% for the third delivery year

(2018-2019). Ameren Illinois will procure 25% of its capacity requirements through the MISO PRA for the second and third delivery years.

6. Approve the procurement of capacity by MidAmerican to meet the quantity of MidAmerican's forecast capacity shortfall for the first delivery year (2016-2017) through the MISO PRA.
7. Approve a capacity procurement for MidAmerican in sufficient quantities to meet 100% of the forecast capacity shortfall for the 2017-2018 through the 2021-2022 delivery years in a bilateral procurement event in the fall of 2016 based on MidAmerican's July 2016 expected load forecast which will be pre-approved by the ICC as part of the approval of this Plan, subject to the review of the IPA and consensus among the IPA, ICC Staff, MidAmerican and the Procurement Monitor. The IPA recommends consensus among the IPA, ICC Staff, MidAmerican and the Procurement Monitor because the capacity requirements for the 2021-2022 delivery year will not be known until MidAmerican produces the July 2016 load forecast.
8. Approve pro-rata curtailment of ComEd and Ameren Illinois' Long-Term Power Purchase Agreements for renewable energy in the unlikely event that the updated March 2016 expected 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 2 above. Otherwise, the July 2015 forecast will form the basis for curtailment.
9. Approve a spring 2016 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 (solar photovoltaic only for Ameren Illinois and ComEd, all categories for MidAmerican). The volume for the procurement will be determined based upon the "Remaining Target" quantities resulting from the utilities' March, 2016 load forecasts and limited to the funds available according to the utilities' updated budgets.
10. Approve a fall 2016 procurement of distributed generation RECs using already collected hourly ACP funds for Ameren Illinois and ComEd, and the Renewable Resources Budget for MidAmerican.
11. Approve consensus items from the 2015 energy efficiency stakeholder workshops and prior years' energy efficiency stakeholder workshops related to the implementation of Section 16-111.5B of the IPA Act.
12. Approve the Section 16-111.5B incremental energy efficiency programs identified by the Agency for approval in Chapter 7.

The Illinois Power Agency respectfully posts this draft Procurement Plan, which the IPA believes is compliant with all applicable law, for public comment with a due date for comments of September 14, 2015.

2 Legislative/Regulatory Requirements of the Plan

This Section of the 2016 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"),[4] benefit from retail and wholesale competition. The objective of the Act was to improve the process to procure electricity for those customers.[5] 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."[6] 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.[7]

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 pursuant to Section 16-111.5 of the Public Utilities Act ("PUA").[8] 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.[9] 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"[10] and "Procurement Administrator."[11] The Illinois Commerce Commission ("Commission") is tasked with approval of the plan and monitoring of the procurement events through a Commission-hired "Procurement Monitor."[12]

2.2 Procurement Plan Development and Approval Process

Although the elements of procurement planning process are ongoing, with the Agency incorporating stakeholder input and lessons from past proceedings, the formal process for composing the 2016 Procurement Plan began on July 15, 2015. By that date, each Illinois utility that procures electricity through the IPA (ComEd, Ameren Illinois, and for 2016, MidAmerican) had 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 expected scenarios for the load of the eligible retail customers.

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[4] 220 ILCS 5/16-111.5(a).
[5] 20 ILCS 3855/1-5(2); 3855 /1-5(3); 3855/1-5(4).
[6] 20 ILCS 3855/1-5(1).
[7] 20 ILCS 3855/1-5(4).
[8] 20 ILCS 3855/1-20(a)(2), 3855/1-75(a).
[9] 20 ILCS 3855/1-20(a)(1). As indicated in Chapter 1, through a letter to the IPA dated April 9, 2015, MidAmerican has elected to participate in the 2016 Procurement 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.")
[10] 20 ILCS 3855/1-75(a)(1).
[11] 20 ILCS 3855/1-75(a)(2).
[12] 220 ILCS 5/16-111.5(b), (c)(2).

Next, the IPA prepared a draft Procurement Plan. This document constitutes that draft Plan. On August 14, 2015, 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 IPA releases its draft plan. The 2016 Plan comment period concludes on Monday September 14, 2015. During the 30-day comment period, the Agency is required to hold one public hearing within each utility's service area for the purpose of receiving public comment on the procurement plan;[13] those public hearings are scheduled for September 4th in Moline, September 9th in Springfield, and September 10th in Chicago. After the receipt of public comment and within fourteen days following the end of the 30-day review period (*i.e.*, no later than September 28, 2015), the IPA must file its revised Procurement Plan with the Commission for approval.[14] Objections to this Plan must be filed with the Commission within five days after the filing of the Plan;[15] typically, the Administrative Law Judge sets the dates for Responses and Replies to Objections by Ruling shortly after the docket opens. The Commission must enter an order confirming or modifying the Plan within 90 days after it is filed by the IPA;[16] assuming the Agency files its 2016 Plan on September 28, 2015, this year's deadline will be Sunday, December 27, 2015 (leading to a Monday, December 28, 2015 deadline). The current ICC calendar indicates the last scheduled meeting prior to that deadline is on Tuesday, December 22, 2015.

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."[17]

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 all other legal requirements (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.[18] 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.[19] 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 preexisting contracts,[20] 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.[21]
- 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.[22] Such standard wholesale products include, but are not limited to, monthly 5 x 16 peak period block energy, monthly off-peak wrap

[13] 220 ILCS 5/16-111.5(d)(2).
[14] Id.
[15] 220 ILCS 5/16-111.5(d)(3).
[16] Id.
[17] 220 ILCS 5/16-111.5(d)(4).
[18] 220 ILCS 5/16-111.5(b)(1)(i)-(iv).
[19] 220 ILCS 5/16-111.5(b)(2), (b)(2)(i).
[20] 220 ILCS 5/16-111.5(b)(3).
[21] 220 ILCS 5/16-111.5(b)(i), (b)(iii).
[22] 220 ILCS 5/16-111.5(b)(3)(iv).

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.[23]

- Detail the proposed term structures for each wholesale product type included in the portfolio of products.[24]
- 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.[25] 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, the Plan should 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. [26]
- Include renewable resource and demand-response products, as discussed below.

2.4 Standard Product Procurement and Load-Following Products

As noted in Section 2.3, the IPA Act provides examples of "standard wholesale products."[27] This listing has been understood by the Commission to be non-exhaustive and non-static.[28] 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" 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."[29]

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,[30] the IPA understands that the definition of "standard product" to also include 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.[31] With respect to demand-side products, in approving the 2015 Plan the Commission determined that block super-peak energy efficiency products proposed for procurement by the Agency "should not be procured at this time," but left open the possibility that "as demand-side markets evolve and energy efficiency products become more

[23] Id.
[24] 220 ILCS 5/16-111.5(b)(3)(v).
[25] 220 ILCS 5/16-111.5(b)(3)(vi).
[26] 220 ILCS 5/16-111.5(b)(4).
[27] 220 ILCS 5/16-111.5(b)(3)(iv).
[28] 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").
[29] Docket No. 14-0588, Final Order dated December 17, 2014 at 156.
[30] 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").
[31] *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.

standardized, the Commission could envision a time in which these products might satisfy Section 16-111.5 of the PUA."[32]

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.[33] "Renewable energy resources" is defined in the Illinois Power Agency Act, and means (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 others as identified in the IPA Act.[34] 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, 2016, at least 11.5% of each utility's total supply should be generated from renewable energy resources.[35]

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 (2016) Procurement Plan, to the extent cost-effective resources are available, the IPA is directed to procure at least 75% of the renewable energy resources from wind generation, 6% from photovoltaics, and 1% from distributed renewable energy generation devices.[36] Renewable energy resources procured from distributed generation devices to meet this requirement may also count towards the required percentages for wind and solar photovoltaics.[37] In other words, if the IPA procures the required 1% distributed generation renewable energy resources and the resources used to meet that standard are all generated from photovoltaics, those resources also count toward the 6% solar photovoltaics sub-target, leaving 5% solar photovoltaics to be procured from other sources. In Docket No. 14-0588 approving the Agency's 2015 Plan, the Commission confronted the question of whether, should the overall renewable energy resource requirements for the upcoming delivery year be met (via existing long-term contracts), procurements may be conducted to satisfy the sub-target percentage goals specific to generating technologies.[38] In that proceeding, the Commission approved the Agency's proposal to conduct a procurement of renewable energy credits from photovoltaic systems over the objections of ComEd and Ameren Illinois (who viewed the procurement as "unnecessary"), stating that it was "clearly supported by the record."[39]

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."[40] This can be applied somewhat cleanly to ComEd and Ameren Illinois, as "each utility's total supply 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 <u>all or a portion</u> of its eligible Illinois retail customers in accordance with the applicable provisions set forth in this

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[32] Docket No. 14-0588, Final Order dated December 17, 2014 at 156.
[33] 20 ILCS 3855/1-5(5), 1-5(6).
[34] 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.")
[35] 20 ILCS 3855/1-75(c)(1).
[36] Id.
[37] Id.
[38] See generally Docket No. 14-0588, Final Order dated December 17, 2014 at 286 (and associated discussion).
[39] Id. However, in past procurement plan proceedings, the Commission has also approved Agency proposals not to 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 amount of resources to be procured relative to the procurement's administrative costs. (See generally Docket Nos. 12-0544, 13-0546).
[40] 20 ILCS 3855/1-75(c)(1).

Section and Section 1-75 of the Illinois Power Agency Act."[41] This raises 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. Further discussion on this subject can be found in Chapter 8.

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 a "benchmarks" "based on market prices for renewable energy resources in the region" against which all bids are measured.[42] 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.[43]

These values are now fixed for Ameren Illinois and ComEd, and the greater of the two is 0.18054 ¢/kWh for Ameren Illinois, and 0.18917 ¢/kWh for ComEd. For MidAmerican, the value is expected to be 0.12415 ¢/kWh.

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.[44] 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."[45]

The IPA's 2015 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 2015 load forecasts indicate that the eligible retail customer rate cap would be exceeded under the expected load forecast.[46] As discussed in later chapters, with significant amounts of load having switched back to utility service, the likelihood that existing long-term power purchase agreements may need to be curtailed for the 2016-2017 delivery year is very low.

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."[47] As part of the 2015 Plan, 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.[48]

[41] 220 ILCS 5/16-111.5(a) (emphasis added).
[42] 20 ILCS 3855/1-75(c)(1).
[43] 20 ILCS 3855/1-75(c)(2)(E).
[44] 20 ILCS 3855/1-75(c)(3).
[45] Id.
[46] See Docket No. 14-0588, Final Order dated December 17, 2014 at 6 (authorization of curtailment if necessitated by rate impact cap was not a disputed issue). Ultimately, the Spring 2015 load forecasts did not demonstrate that a curtailment was required.
[47] 20 ILCS 3855/1-75(c)(5).
[48] Docket No. 14-0588, Final Order dated December 17, 2014 at 6. As curtailments were ultimately not necessary, no funds will be spent on curtailed RECs.

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.[49]

A generation source is considered a "distributed renewable energy generation device" 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.[50]

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.[51]

The IPA's 2015 Plan featured the first distributed generation-specific procurement approved by the Commission. That procurement process is scheduled to begin in September 2015, with bid selection and contract execution set to occur in October.[52] Resulting contracts will be for 5 years beginning with the 2015-2016 delivery year 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 Fall 2015 DG procurement and use that information to inform the amount to be procured in future renewables, wind, photovoltaics, and distributed generation procurements (including procurements for the 2016-2017 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.[53] 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 utilities).[54] Resources procured using the RERF thus cannot be used to meet the utilities' Section 1-75(c) renewable energy resources procurement targets.

[49] 20 ILCS 3855/1-75(c)(1).
[50] 20 ILCS 3855/1-10.
[51] 20 ILCS 3855/1-56(b).
[52] As MidAmerican had not elected to participate in the 2015 Procurement Plan, this procurement is being conducted only for ComEd and Ameren Illinois.
[53] 20 ILCS 3855/1-56(a).
[54] See generally Docket No. 12-0544, Final Order dated December 19, 2012 at 112-113.

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.[55] 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,[56] with its payment rate determined by results from the procurement of renewable energy resources using the renewable resources budget.[57] 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.[58]

In recognition of the constraints present in attempting to conduct procurements from the RERF without more express statutory authorization,[59] 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.[60] The IPA's Supplemental Photovoltaic Procurement Plan was filed with the Commission on October 28, 2014 and approved on January 21, 2015. The IPA conducted its first procurement pursuant to its Supplemental Plan in May 2015 with a budget of $5 million.[61] Subsequent procurements are scheduled for November 2015 ($10 million) and March 2016 ($15 million), with a potential contingency procurement tentatively scheduled for spring 2017 should there be unspent funds.

2.6 Energy Efficiency Resources

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 or to implement additional cost-effective energy efficiency programs or measures.[62] 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."[63] 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.[64]
- 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.[65]
- 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

[55] 220 ILCS 5/16-115D(d)(4).
[56] 220 ILCS 5/16-115D(b).
[57] 220 ILCS 5/16-115D(d)(1).
[58] 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.
[59] For a discussion of these constraints, see the IPA's Supplemental Photovoltaic Procurement Plan at 3-4.
[60] http://ilga.gov/legislation/publicacts/fulltext.asp?Name=098-0672
[61] Information about the results of that procurement may be found at http://www.illinois.gov/ipa/Documents/IPA-June-2015-SPV-announcement.pdf.
[62] 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.
[63] 220 ILCS 5/16-111.5B(a)(3).
[64] 220 ILCS 5/16-111.5B(a)(3)(A).
[65] 220 ILCS 5/16-111.5B(a)(3)(B).

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.[66]

- 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.[67]
- 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.[68]
- An energy savings goal, expressed in megawatt-hours, for the year in which the measures will be implemented.[69]
- For each expanded or new program, the estimated amount that the program may reduce the agency's need to procure supply.[70]

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; MidAmerican asserts that because it does not fall under the purview of Section 8-103 of the PUA,[71] many of the requirements of Section 16-111.5B are not applicable to it (while also providing substantive responses and accompanying information where appropriate).[72] Further discussion of the applicability of Section 16-111.5B to MidAmerican can be found in Chapter 7.

These assessments were delivered to the IPA on July 15th to aid the Agency in the development of its 2016 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; the utilities are directed to factor in the associated energy savings to the load forecast.[73] 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.[74]

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:[75]

> *"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*

[66] 220 ILCS 5/16-111.5B(a)(3)(C).
[67] 220 ILCS 5/16-111.5B(a)(3)(D).
[68] 220 ILCS 5/16-111.5B(a)(3)(E).
[69] 220 ILCS 5/16-111.5B(a)(3)(F).
[70] 220 ILCS 5/16-111.5B(a)(3)(G).
[71] 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.").
[72] See Appendix D, MidAmerican Energy Company's Election to Procure Power and Energy for a Portion of its Eligible Illinois Retail Customers.
[73] 220 ILCS 5/16-111.5B(a)(4).
[74] 220 ILCS 5/16-111.5B(a)(5).
[75] 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.").

included of financial costs likely to be imposed by future regulations and legislation on emissions of greenhouse gases.[76]

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. As the Commission recognized in its Order approving the 2015 Plan, "[a] significant problem with procurement proceedings is the expedited schedule combined with a relatively large number of contested issues and parties," making it "difficult for the Commission to deal with complex economic issues" such as those related to TRC methodology.[77] Further discussion of the energy efficiency-related workshops required from the Order approving the 2015 Plan and the contested issues to be 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 7.

Additionally, past years' disputes have resulted in a series of Commission-mandated workshops leading to consensus language being reached among stakeholders. As some parties have questioned the applicability of past Commission-approved consensus language to future solicitations and contracts, all such consensus language reached in prior years is included this year in Appendix B-2 and the IPA is expressly requesting that such language be approved by the Commission with the intention that it be applied prospectively, informing 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 2017 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."[78] 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.[79] Specifically:

- The demand-response measures must be procured by a demand-response provider from eligible retail customers;
- 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;[80]
- 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;[81]; 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.[82]

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

[76] 20 ILCS 3855/1-10.
[77] Docket No. 14-0588, Final Order dated December 17, 2014 at 224.
[78] 220 ILCS 5/16-111.5(b)(3)(ii).
[79] 220 ILCS 5/16-111.5(b)(3)(ii).
[80] 220 ILCS 5/16-111.5(b)(3)(ii)(A); 16-111.5(b)(3)(ii)(B).
[81] 220 ILCS 5/16-111.5(b)(3)(ii)(C); 16-111.5(b)(3)(ii)(D).
[82] 220 ILCS 5/16-111.5(b)(3)(ii)(E).

Commission within 60 days after the Commission has approved the utility's AMI Plan.[83] 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.[84] These programs are discussed further in Section 7.5, where demand response resource choices are examined.

On May 23, 2014, a panel of the U.S. Court of Appeals for the D.C. Circuit voted 2-1 to invalidate FERC Order 745, which created a uniform compensation structure for demand response participation in wholesale energy markets.[85] The ruling creates no new obligations for the IPA, but could impact the degree to which demand response providers look to state policy as a mechanism to monetize demand response. In early May, the U.S. Supreme Court granted petitions for writs of certiorari in the matter, and the case is expected to be heard during the Court's October term.[86] Further discussion of this ruling can be found in Section 7.5.

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.[87] As a part of the goal, the Plan must also include electricity generated from clean coal facilities.[88] While there is a broader definition of "clean coal facility" contained in the definition section of the IPA Act,[89] Section 1-75(d) describes two special cases: the "initial clean coal facility"[90] 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").[91] 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 FutureGen 2.0 as a "retrofit clean coal facility" starting in the 2017 delivery year. While the Illinois Appellate Court upheld the cost recovery mechanism used in that docket's Order,[92] the matter is currently before the Illinois Supreme Court and its status has been thrown into question by a February 2015 announcement by the U.S. Department of Energy that federal funding for the project would be suspended.[93] Additional discussion of the Clean Coal Portfolio Standard is located in Section 7.6 of the Plan.

2.9 2015 Legislative Proposals

The Spring 2015 session of the Illinois General Assembly saw 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.[94] Among the proposals are the following:

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[83] 220 ILCS 5/16-108.6(g).
[84] 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.
[85] See Electric Power Supply Ass'n vs. FERC, 753 F.3d 216, 225 (D.C.Cir.2014).
[86] http://www.supremecourt.gov/orders/courtorders/050415zor_7648.pdf
[87] 20 ILCS 3855/1-75(d).
[88] 20 ILCS 3855/1-75(d)(1).
[89] 20 ILCS 3855/1-10.
[90] Id.
[91] 20 ILCS 3855/1-75(d)(5).
[92] See Docket No. 12-0544, Final Order dated December 19, 2012 at 228-237; Docket No. 13-0034, Final Order dated June 26, 2013 ("Phase II" approving sourcing agreement as required in Docket No. 12-0544); Commonwealth Edison Co. v. Illinois Commerce Commission, et al., 2014 IL App (1st) 130544, July 22, 2014. As of the date of the Plan being published, this matter remained under consideration by the Illinois Supreme Court.
[93] http://www.chicagobusiness.com/article/20150203/NEWS11/150209921/futuregen-clean-coal-plant-is-dead.
[94] Elements of these proposals also address other aspects of the IPA's work, such as the use of the Renewable Energy Resources Fund; to the extent that those elements are not part of the Agency's planning and procurement process, they are not addressed here.

- SB 1585/HB 3293 would require the Agency include the procurement of low carbon energy resources in its annual procurement plans and competitive procurement processes beginning with the partial planning year commencing on January 1, 2016 through May 31, 2021.

- SB 1879/HB 3328 would require the procurement of photovoltaic RECs from brownfield sites, the development of a "renewable energy resources plan," and would terminate the Section 16-111.5B pathway for the inclusion of energy efficiency programs in annual plans.

- SB 1485/HB 2607 would require the development of a "long-term renewable resources procurement plan" (including a "low-income solar program," a "declining block program," and a "community solar program") and would conditionally terminate the Section 16-111.5B pathway for the inclusion of energy efficiency programs in annual plans.

- SB 1480 would require the inclusion of sourcing agreements between "clean coal facilities" and both utilities and alternative retail electric suppliers as part of each annual procurement plan.

The Agency is actively tracking the status of these bills and any other legislation that could change its powers, duties, and objectives. In addition, on August 3, 2015, the U.S. Environmental Protection Agency released its final 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. Under the Clean Power Plan, initial state compliance plans are due to the U.S. EPA by September 6, 2016, and the development of the Illinois state compliance plan may generate additional legislation of relevance to the Agency.

Senate Resolution 623, adopted May 31, 2015, urges the Illinois Power Agency to do the following:

- Independently review the PJM Interconnection LLC and Midwest Independent System Operator capacity auction rules and market design and determine why the rules and market design have not protected Illinois ratepayers from significant increases;

- Independently investigate whether market power was exercised by any auction participants, including the withholding of certain generation assets intended to drive up the clearing price, and whether the market design for capacity auctions allows for the exercise of market power; and

- Participate in Federal Energy Regulatory Commission proceedings that will address the design and operation of the capacity market planning processes and auction practices utilized by PJM and MISO and to promote policies in those proceedings that will ensure greater transparency, prevent the exercise of market power by bidders, and to deliver capacity resources to Illinois consumers at the lowest and most stable prices.

A review of PJM and MISO capacity auction rules and market design can be found in Chapter 5, while a discussion of the IPA's proposed strategy for hedging capacity for ComEd, Ameren Illinois, and MidAmerican can be found in Chapter 7.

3 Load Forecasts

3.1 Statutory Requirements

Under Illinois law, a procurement plan must be prepared annually for each "electric utility that on December 31, 2005 served at least 100,000 customers in Illinois."[95] Section 16-115(a) of the PUA allows small multi-jurisdictional electric utilities to elect to have the IPA procure power and energy for all or a portion of its eligible load in Illinois. MidAmerican has elected to have the IPA procure incremental amounts of electricity[96], as well as statutorily mandated renewable resources for its eligible customers in Illinois, starting with this plan.[97] The plan must include a load forecast based on an analysis of hourly loads. The statute requires the analysis to include:

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

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

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

The forecasts are prepared by the utilities, but the Procurement Plan is ultimately the responsibility of the 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, the Agency's evaluation of the load forecasts, and a recommendation on the forecasts that the Commission should approve for procurement planning.

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).

[95] 220 ILCS 5/16-111.5(a).
[96] MidAmerican registers with MISO its generation resources allocated to serve its Illinois customers, as historical resources. Incremental amounts of electricity refer to the capacity and energy that would be needed in addition to the historical resources to meet the projected loads.
[97] MidAmerican serves fewer than 100,000 electric customers in Illinois and, as a small multi-jurisdictional electric utility, is not obligated to, but "may elect to procure power and energy for all or a portion of its eligible Illinois retail customers" using the IPA process. 220 ILCS 5/16-111.5(a). This is the first procurement process in which MidAmerican elected to have the IPA procure power and energy for a portion of its Illinois jurisdictional load.
[98] 220 ILCS 5/16-111.5(b)(1).
[99] 220 ILCS 5/16-111.5(d)(1).

3.2 Summary of Information Provided by Ameren Illinois

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

- Ameren Illinois Company ("AIC") Load Forecast for the period June 1, 2016 – May 31, 2021 (See Appendix B)
- Electric Energy Efficiency Compliance with 220 ILCS 5/16-111.5B. This document also contained seven Appendices. (See Appendix B. Note, Ameren Illinois Appendix 6 [Bid Review Information], 8 [Third Party Bids], and 9 [Detailed Analysis] were marked confidential and are not included in Appendix B.)
- Spreadsheets of the expected, high, and low load forecasts.
- Supplemental spreadsheets detailed the renewable portfolio standard targets and budgets under each scenario, capacity needs under each scenario, and the impact on the expected load forecast of incremental energy efficiency programs. (Summarized in Appendix E)

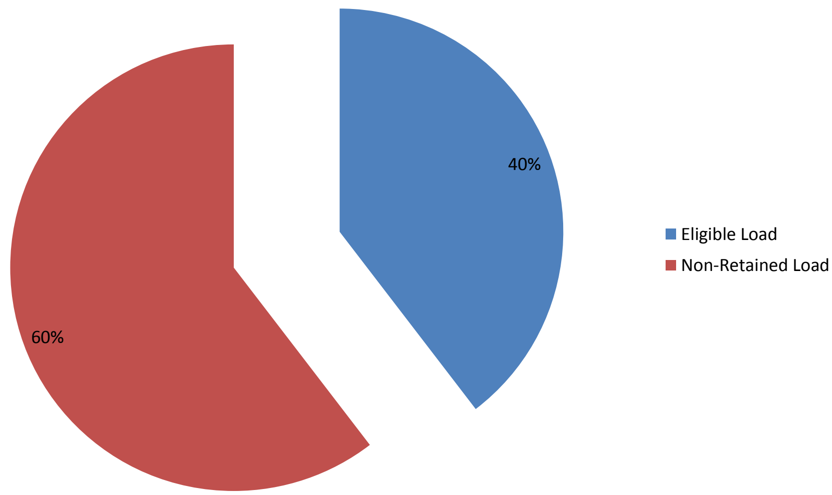
Ameren Illinois uses a combination of statistical and econometric modeling approaches to develop its customer class specific load forecast models. A Statistically Adjusted End-use approach is used for the residential and commercial customer classes. This approach combines the econometric model's ability 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.[100]

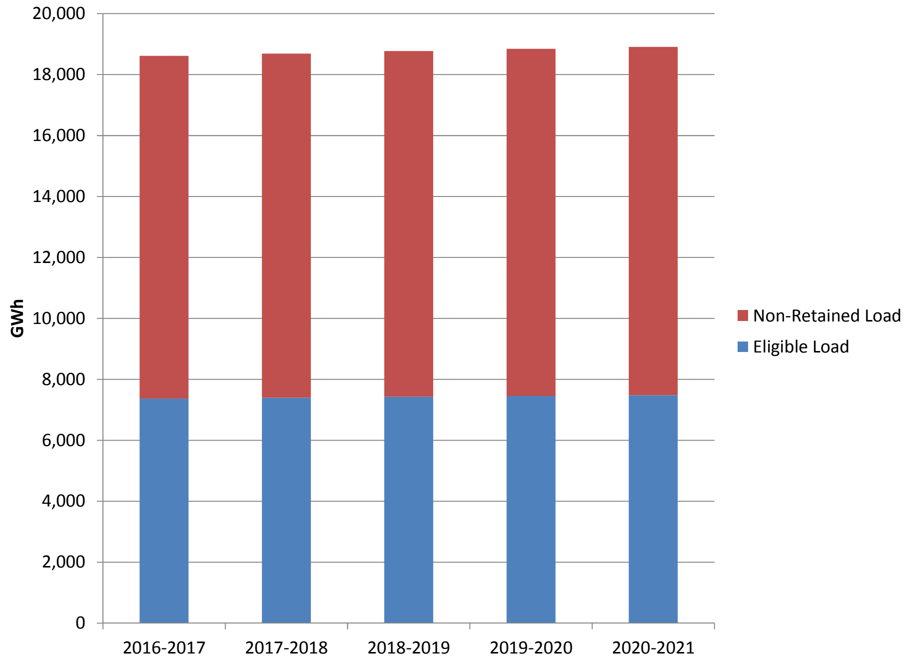
[100] Ameren Illinois assigns load profile classifications at the point of service level and only to points of service that are metered. The classifications are as follows: DS1 – Residential, DS2 – Non-Time of Use Commercial & Industrial with demands less than 150 kW, DS3 – Time of Use Commercial & Industrial 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 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 service from Ameren Illinois or an ARES.

Figure 3-1: Ameren Illinois' Forecast Retail Customer Load Breakdown, Delivery Year 2016-2017



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 customer group.

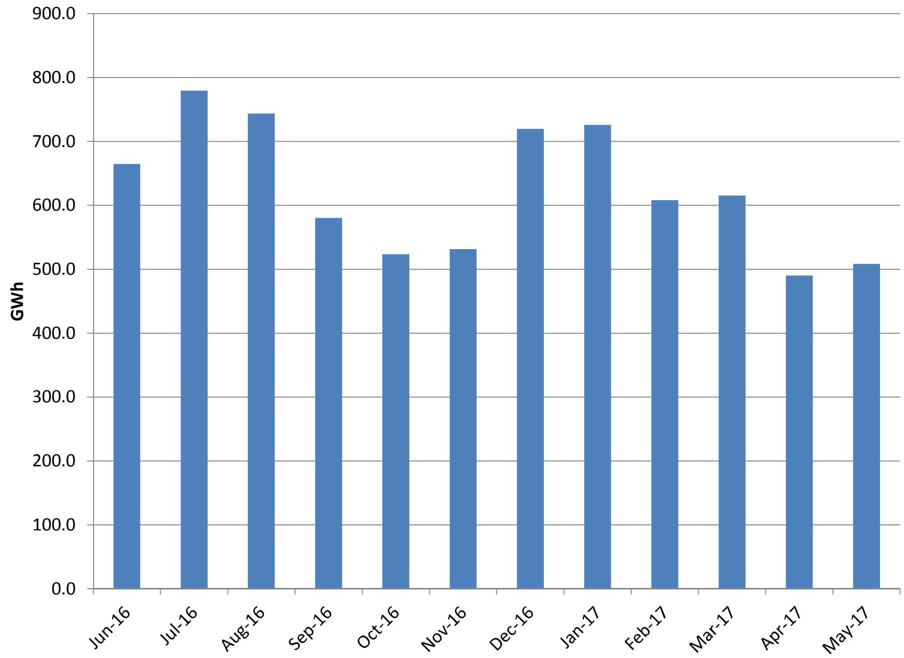
Figure 3-2: Ameren Illinois' Forecast Retail Customer Load by Delivery Year



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 expected or base-case forecast of Ameren Illinois eligible retail load, that is, the load of customers who are eligible for bundled supply procured under this Procurement Plan.

Figure 3-3: Ameren Illinois' Forecast Eligible 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 expected 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

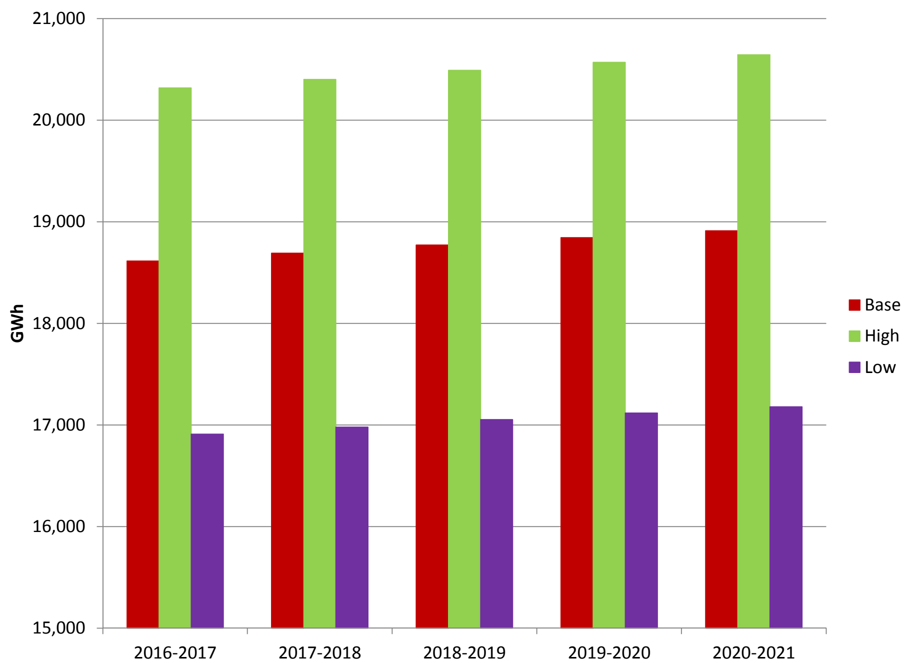
In regression models, residuals indicate the difference between the predicted and actual values. Patterns associated with residuals may indicate the impact of non-specified variables. Because the excursion cases are based on the statistics of the residuals, they reflect the influence of variables not 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 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' Retail Customer Load before Switching in Ameren Illinois' Forecasts



3.2.3 Switching

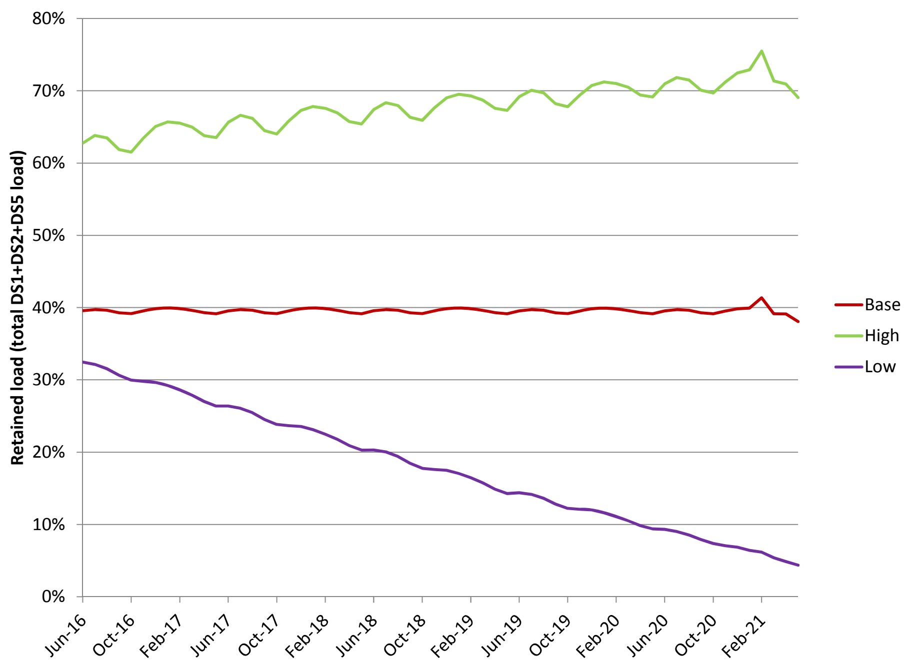
According to Ameren Illinois, customer switching to alternative suppliers, in particular through municipal aggregation, is the greatest driver of load uncertainty. Switching through April 2015 has resulted in approximately 58-64% of residential and small commercial load seeking service from alternative suppliers. Ameren Illinois expects the amount of load supplied by ARES will remain flat across the planning horizon based on indications from municipalities that have contracts expiring. Additionally, Ameren Illinois' current year tariff price is similar to comparable ARES prices. While according to Table 3-2 presented in the next Section, ARES offerings to the 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.

A high load scenario envisions a situation where an even larger return of residential and, to a lesser extent, commercial customers, is realized, especially in June 2016 when approximately 30% of residential load will see contracts under government aggregation expire. Residential and commercial switching rates under the high load scenario are forecasted to be 24% and 54%, respectively, in May 2017, 23% and 51%, respectively, in May 2018, and 19% and 42%, 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' low load scenario assumes that residential and small commercial will approach 71% and 76%, respectively, in May 2017, 77% and 82%, respectively, in May 2018, and 95% 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.

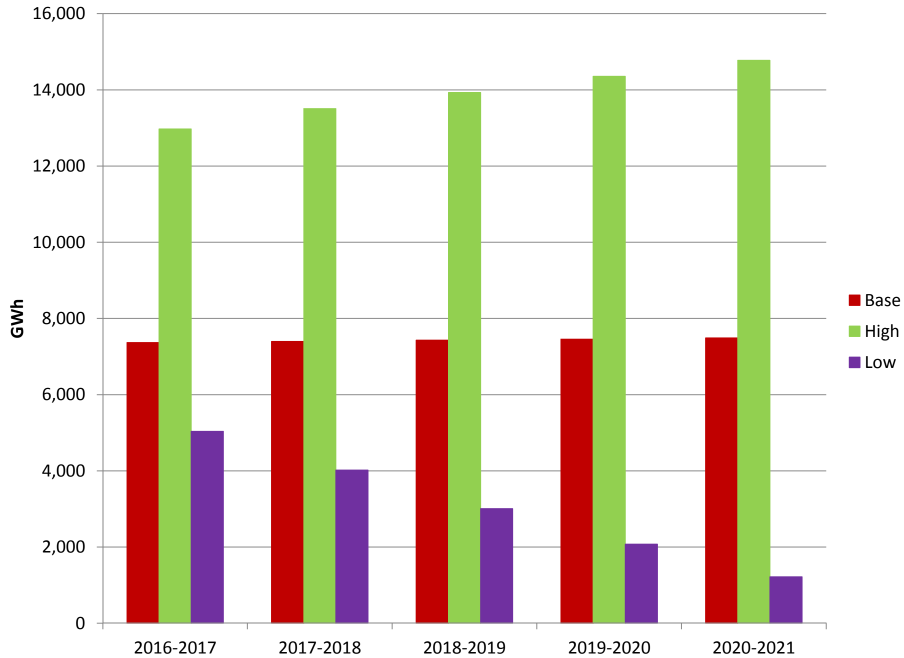
Figure 3-5: Utility Load Retention in Ameren Illinois' Forecasts



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 high-load summer day and Figure 3-8 a low-load 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

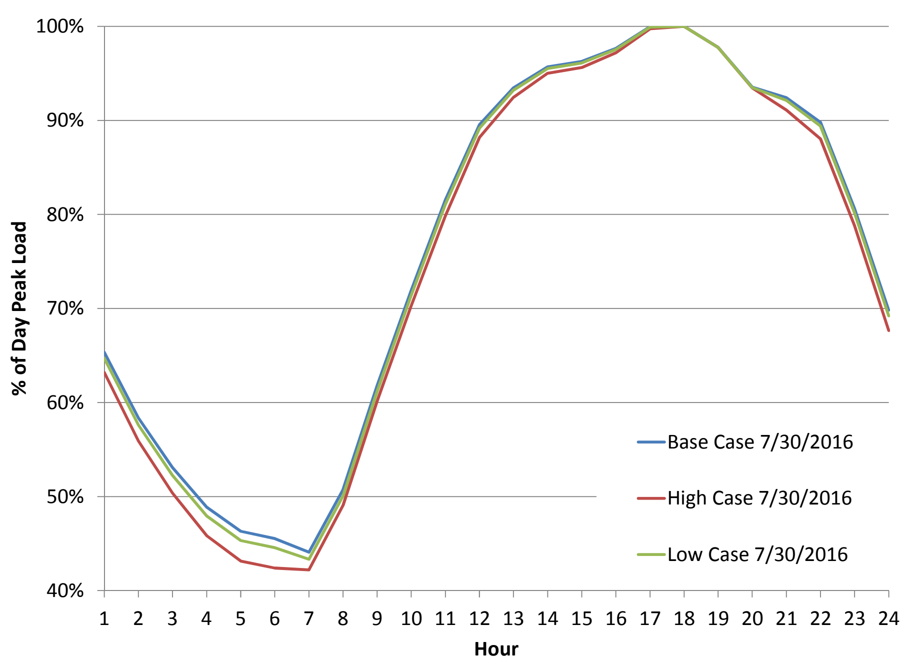
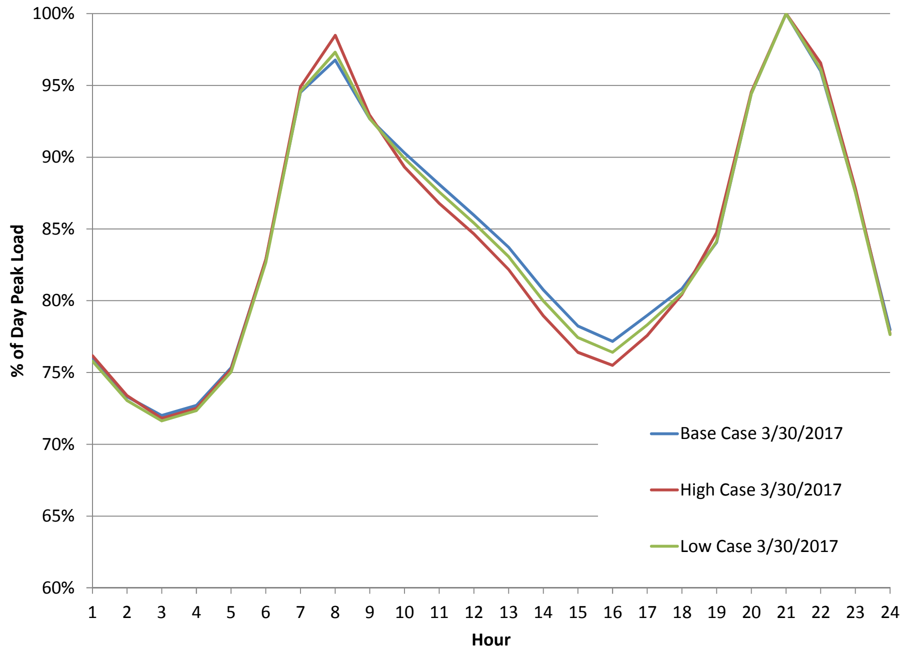
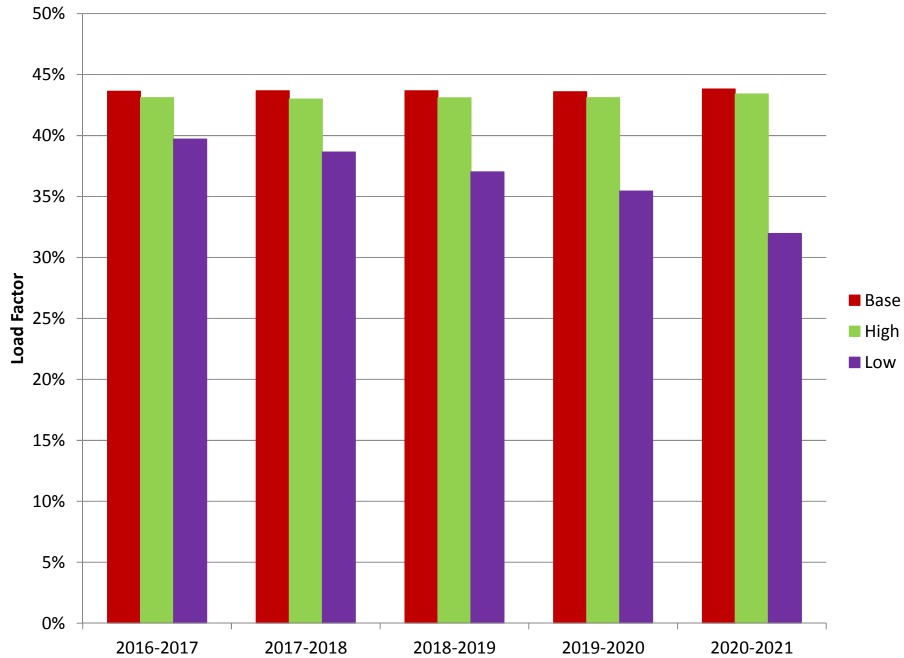


Figure 3-8: Sample Daily Load Shape, Spring Day in Ameren Illinois' Forecasts



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 pickier 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

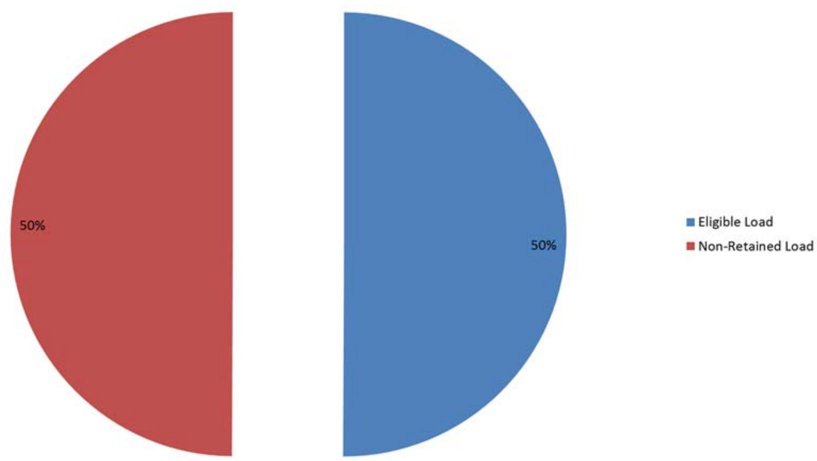
In compliance with Section 16-111-5(d)(1) of the Public Utilities Act, ComEd provided the IPA the following documents for use in preparation of this plan:

- *Load Forecast for Five-Year Planning Period June 2016 – May 2021.* 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.B incremental energy efficiency programs was included as four additional separate documents. (See Appendix C. Note, ComEd also provided an additional document entitled, *Third Party Efficiency Program Results of 2015 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 2016-2017



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 decomposes 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

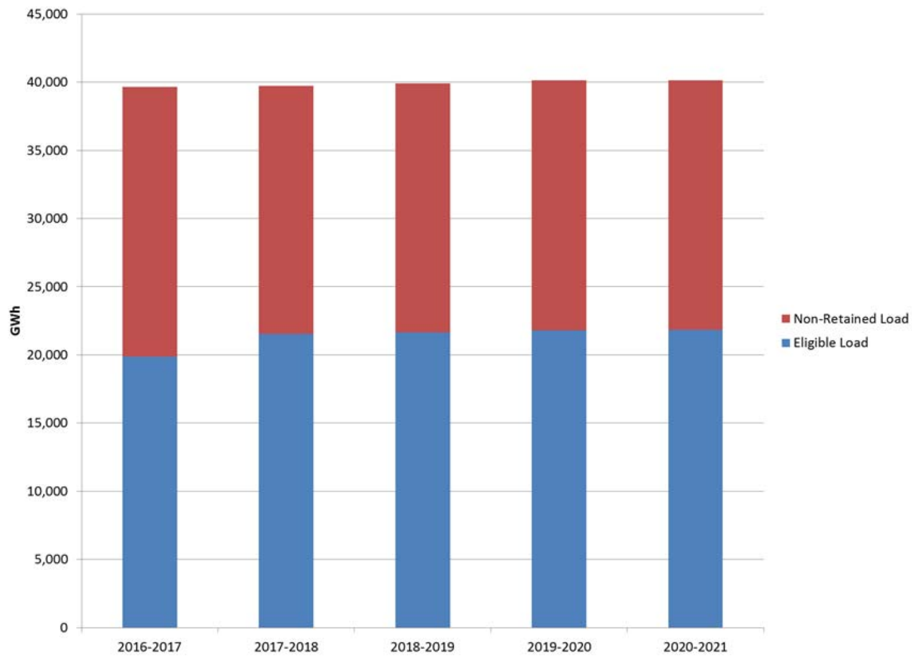
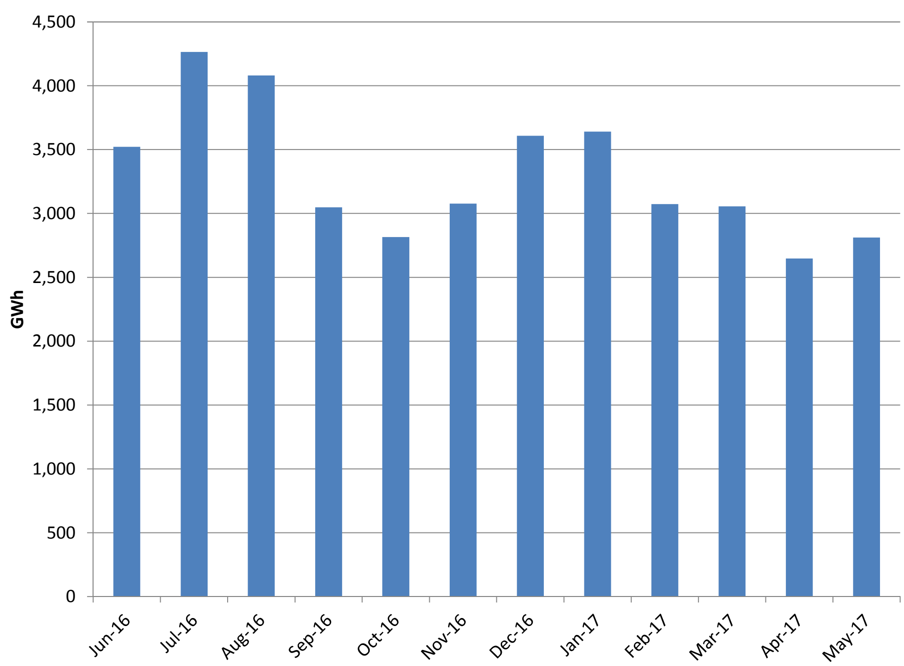


Figure 3-12 provides a monthly breakdown of the expected or base-case forecast of ComEd's eligible retail load, that is, the load of customers who are eligible for bundled supply procured under this Procurement Plan.

Figure 3-12: ComEd's Forecast Eligible Load by Month



ComEd provides a base case and two excursion cases: a low forecast and a high 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 expected 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.

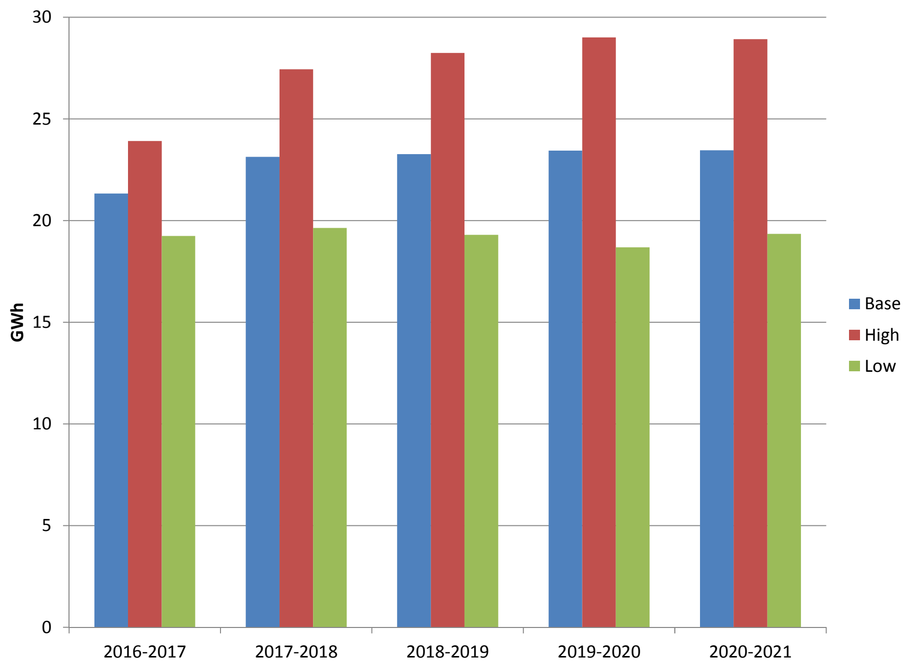
Figure 3-13: Weather Impacts in ComEd's Forecasts

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 2016 and 2017 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 357 communities that had approved aggregation as of April of 2015. That is an increase from the 345 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 for ComEd service in the years 2016 and 2017 such that residential ARES usage declines to approximately 35% in the years 2016 and 2017. 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 high-load summer day, and Figure 3-16 a low-load 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

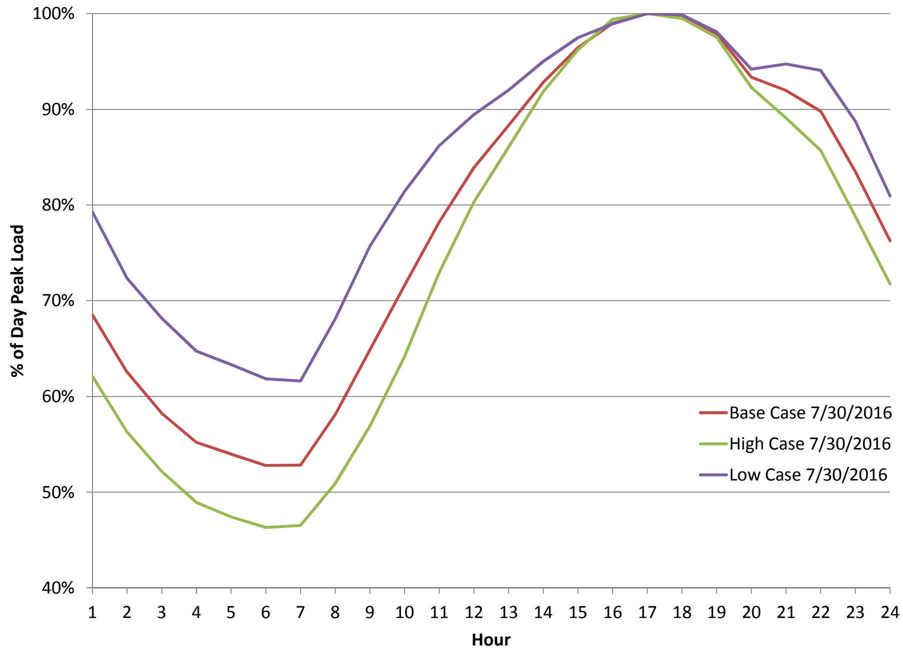
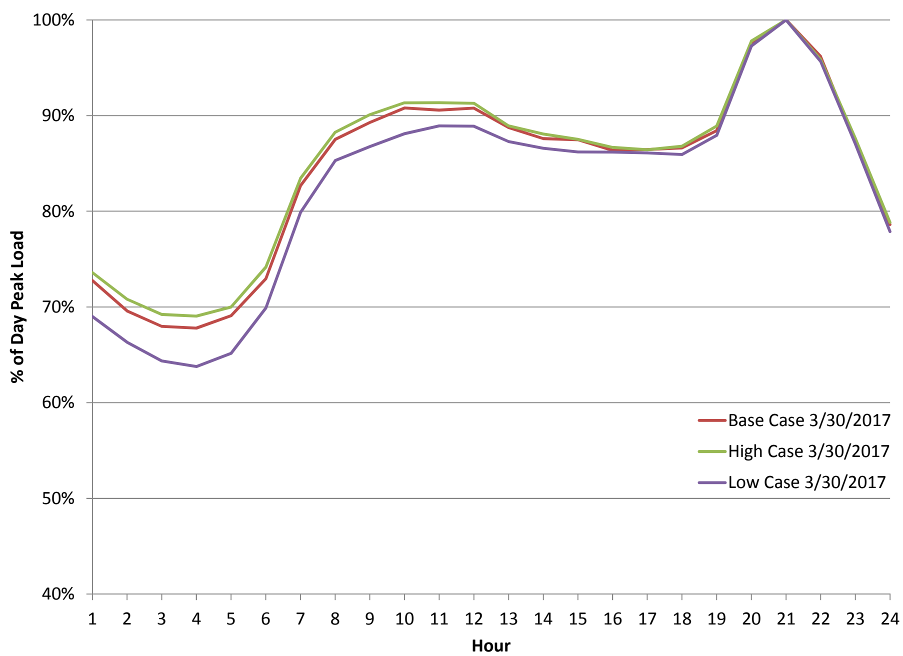


Figure 3-16: Sample Daily Load Shape, Spring Day in ComEd's Forecasts



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 over-averaged 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:

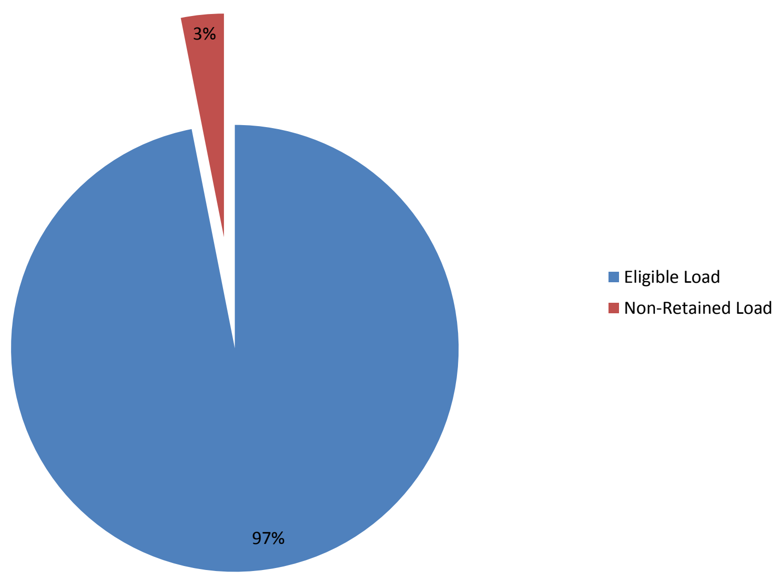
- *Methodology for Illinois Electric Customers and Sales Forecasts: 2016-2025.* This document contained a discussion of load forecast methodology for all MidAmerican scenarios and supporting data for the base scenario forecast. The load forecast included a multi-year historical analysis of hourly load 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 customer classes, except the customer accounted for being served by an ARES. Pursuant to Section 16-111.5(d)(1), MidAmerican's load forecast covered a five-year procurement planning period.
- MidAmerican's Election to Procure Power and Energy for a Portion of its Eligible Illinois Retail Customers Procurement Year – 2016 (Supplemental Procurement Plan Information). This document, with 6 attachments, further addressed the load forecast approach, switching trends, and energy efficiency.
- Spreadsheets of load profiles, hourly load strips, model inputs, 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. Since there are planned large load additions,[101] using the model results alone for the peak demand forecast would result in a forecast that is too low. Therefore, the planned large load additions are added to the model results to achieve the final peak demand forecast.

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 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: a 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 2016-2017



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.

101 The 3M plant located in Cordova, IL added 10 MW of load in 2015 Q1. Since this load addition was not picked up in the data used to estimate the model, using the model results alone for the peak demand forecast would result in a forecast that is too low. Therefore, the 10 MW load addition was added to the model results to achieve the final peak demand forecast.

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 decomposes 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

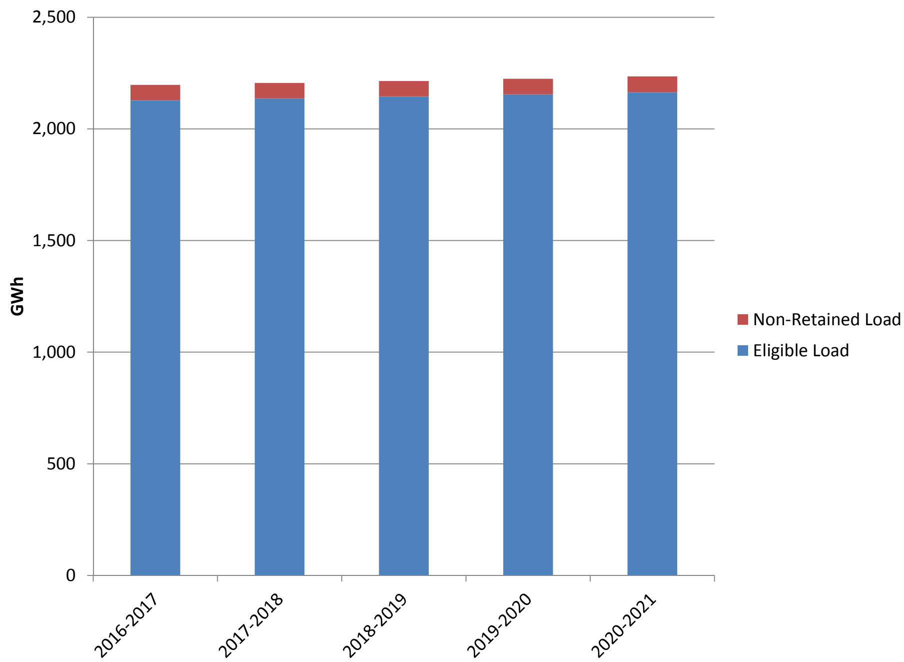
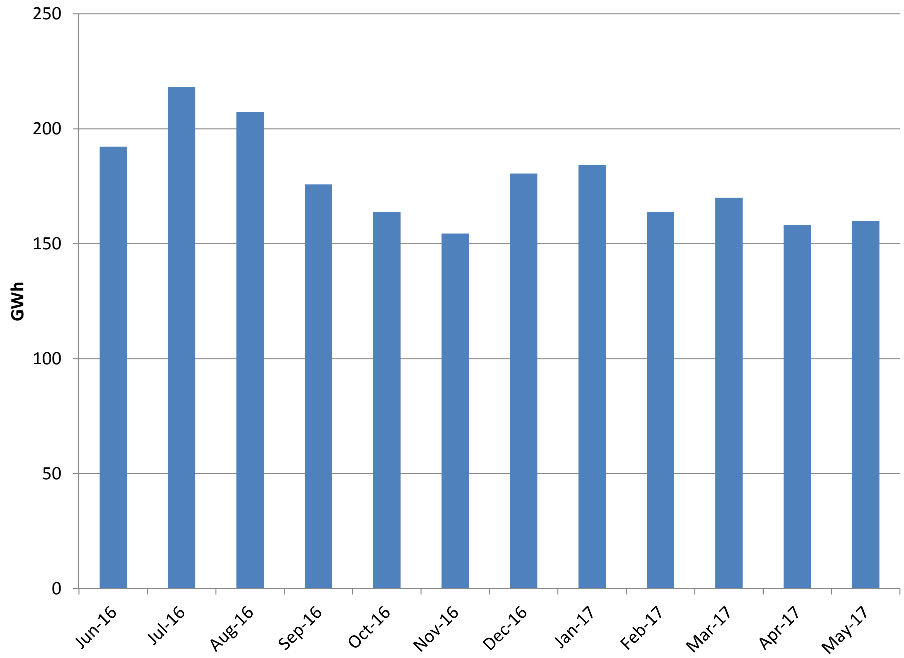


Figure 3-20 provides a monthly breakdown of the expected or base case forecast of MidAmerican retained retail load, that is, the load of customers on bundled supply to be considered under this Procurement Plan.

Figure 3-20: MidAmerican's Forecast Eligible Load by Month



MidAmerican provides a base case and two excursion cases: a low forecast and a high 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 high-load summer day, and Figure 3-23 shows a low-load spring day. There is no difference between the base, low and high load shapes on a summer day, and there is a slight difference between the load shapes on a sample spring day.

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

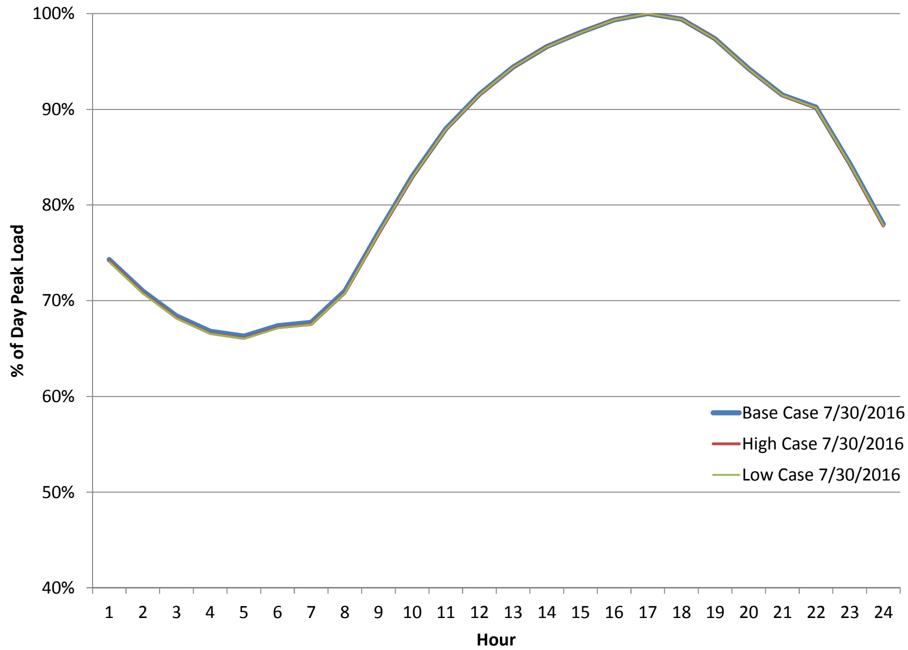
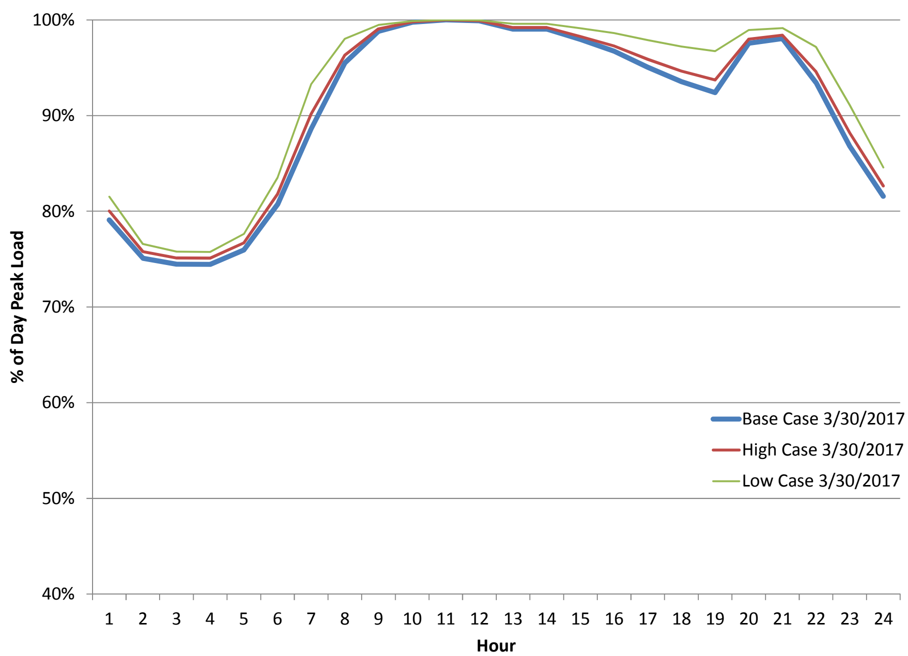


Figure 3-23: Sample Daily Load Shape, Spring Day in MidAmerican's Forecasts



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 52-56% 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-down approach.

Ameren Illinois does not explicitly address uncertainty in load growth. In other words, they do not define "load growth scenarios" and examine the consequences of high or low load growth. They address 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 their 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 their base or expected 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

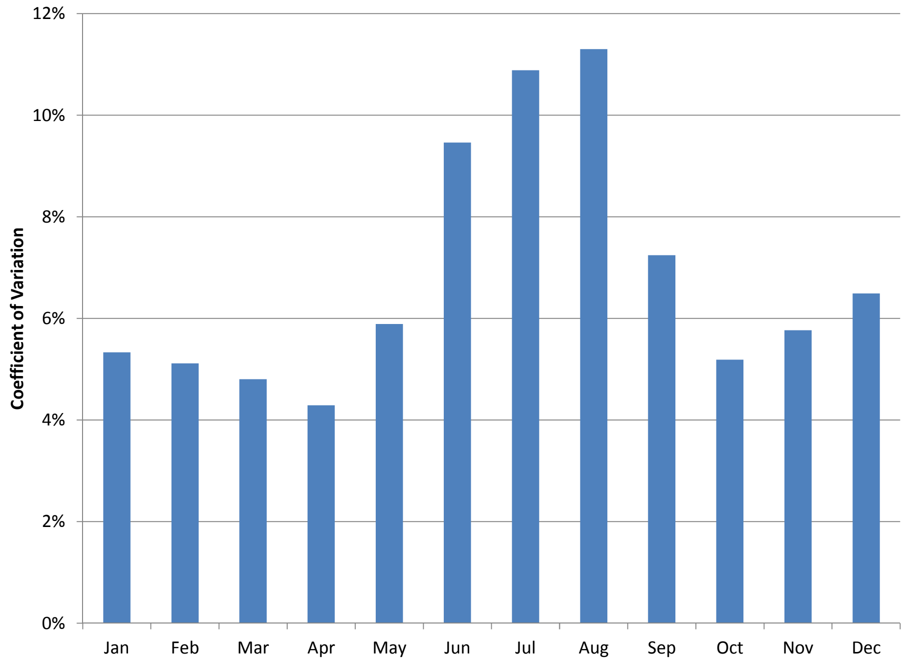
On a short-term basis, weather fluctuations are a key driver of the uncertainty in load forecasts, and in the daily variation of load forecasts around an average-day forecast. The discussion of high and low scenarios, Sections 3.2.2, 3.3.2, and 3.4.2 notes the way that Ameren Illinois, ComEd, and MidAmerican have incorporated weather variation into their 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 reference case weather-related assumptions are not changed for the high and low load forecasts. The reference case load forecast is based 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 expected hourly load and expected hourly cost.

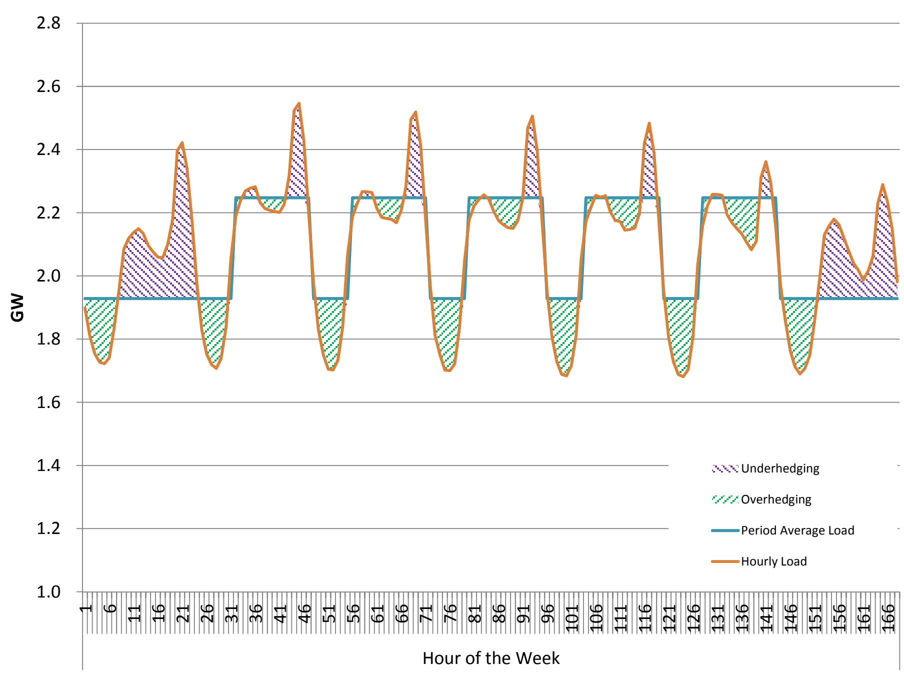
Figure 3-25 illustrates this disconnect by showing, for each month, the average historical "daily coefficient of variation" for peak period loads. This figure is based on historical ComEd loads from 2009 through 2014, normalized to the monthly base case forecasts in the first delivery year. To calculate 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



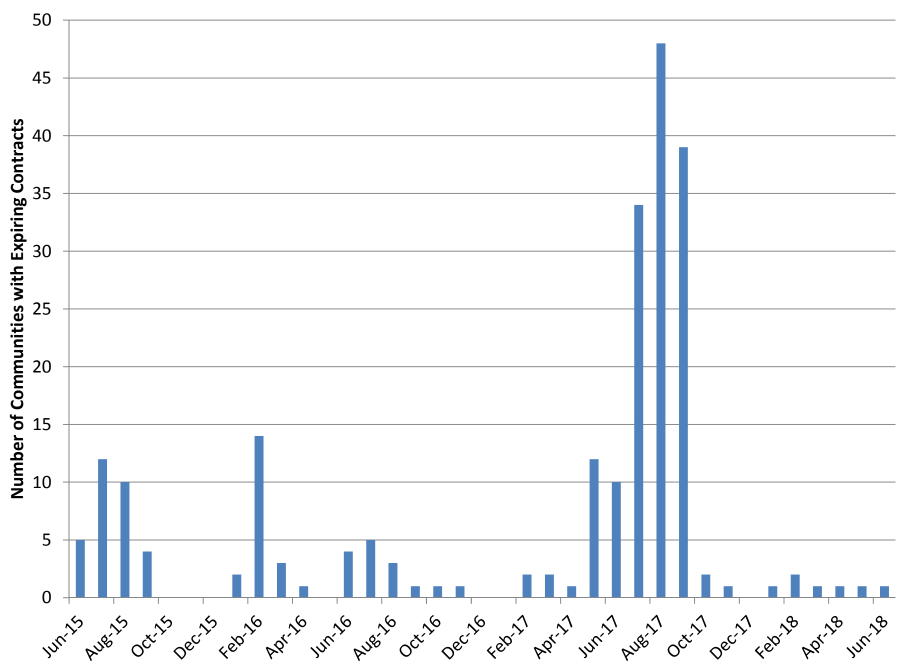
3.5.4 Municipal Aggregation

In their base cases, Ameren Illinois projects 60.8% switching by eligible retail customers by the end of the 2016-2017 delivery year and ComEd projects about 46.2%. These levels represent a decline in the switching statistics assumed in the July 2014 forecasts and are informed by lower than forecasted actual switching through April 2015 driven in part by communities deciding to suspend and/or not renew their municipal aggregation programs and return to utility service. Savings opportunities that existed prior to 2014 drove the growth in residential switching, but since 2014 these savings have been diminishing and in some cases eliminated.

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 but 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.

As shown in Figure 3-27, approximately one quarter of the current supply contracts for municipal aggregation will expire in the 2015-2016 delivery year. However, as shown in Figure 3-27, the majority of the supply contracts are scheduled to expire by the end of the summer period of 2017. It is possible that many of the renewal offers made by the suppliers to municipal aggregations may be high relative to utility bundled supply prices, so there may be a considerable amount of return to utility service. This is especially true if market prices rise between now and the expiration of municipal aggregation contracts. On the other hand, switching could be higher than expected, resulting in an over-hedged position. Expanding on the hypothetical, assuming that the utilities' hedges are above market prices, the remaining load taking bundled utility service would be subject to higher bundled rates. Both Ameren Illinois and ComEd have assumed a wide range of switching fractions in their low and high scenarios (return to utility service would be represented as a decrease in the switching fraction over time).

Figure 3-27: Distribution of Municipal Aggregation Contract Expirations (ComEd)



3.5.5 Individual Switching

ARES offer a variety of products to customers – some of which have a similar structure to the utility bundled service, and some 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.[102] 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[103] and representative ARES prices[104] available to eligible utility customers. It appears that, at the current time, 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.

Table 3-2: Representative ARES Fixed Price Offers (Offers without an explicit premium renewable component) and Utility Price to Compare

Utility Territory	Utility Price to Compare (¢/kWh)	Representative ARES Price (¢/kWh)
Ameren Illinois (Zone I)	5.97	7.12
Ameren Illinois (Zone II)	5.91	7.18
Ameren Illinois (Zone III)	5.97	7.12
ComEd	7.03	8.04

3.5.6 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." Therefore, these hourly rate customers are not part of the utilities' supply portfolio and the IPA does not have to 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.

3.5.7 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.[105] 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

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[102] For more information on choices offered by ARES, see the 2015 Annual Report of the ICC Office of Retail Market Development at http://www.icc.illinois.gov/downloads/public/2015%20ORMD%20Section%2020-110%20report.pdf.

[103] July 2015 utility cost to compare from http://www.pluginillinois.org/MunicipalAggregation.aspx.

[104] Representative ARES prices are an average of 12-month fixed price offers from ARES available at http://www.pluginillinois.org/OffersBegin.aspx as of July 23, 2015.

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

Plan. Section 7.1 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,[106] 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.

3.5.8 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 7.5 of the Plan contains the IPA's discussion and recommendations for demand response resources.

3.5.9 Emerging Technologies

The Agency's 2015 *Annual Report: The Costs and Benefits of Renewable Resource Procurement* included a section on the impact of energy storage on renewable resource procurement.[107] Recent announcements such as Tesla's Powerwall home energy storage system suggest that energy storage is now an emerging technology. 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 7. The March 2016 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 average hourly load in each of the peak and off-peak sub-periods, and the high and load cases represent significant variation in those averages.

As illustrated in Figure 3-28, the Ameren Illinois low and high load forecasts are on average equal to 68% and 176% of the base case forecast, respectively, during the 2016-2017 delivery year. Comparatively, for the same period, ComEd's low and high load forecasts are on average equal to 91% and 111% of the base forecast, respectively. This reflects the differences in switching assumptions used by the two utilities. MidAmerican's low and high load forecast deviations from the base case are flat and symmetrical being equal to 86% and 114%, 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 pure mathematical construct.

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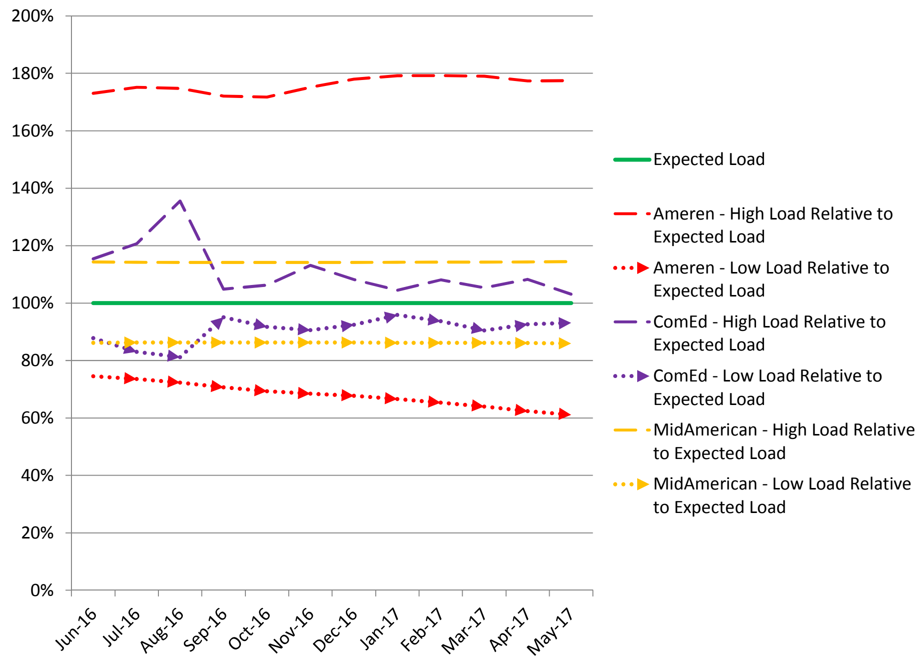
[106] See 220 ILCS 5/8-408.

[107] That report can be found here: http://www.illinois.gov/ipa/Documents/IPA-2015-Cost-Benefits-Renewables-Report-4-1-15.pdf

Figure 3-28: Comparison of Ameren Illinois', ComEd's, and MidAmerican's High and Low Forecasts for Delivery Year 2016-2017



Another use of the high and low cases will be to estimate 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 load is unhedged is that one attempts to hedge a variable, or shaped, load with a product whose delivery is constant. The spot price at which the unhedged volumes are covered is positively correlated with load. 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 expected load shape may have an overstated load factor like that of ComEd, and no other forecast case is available for comparison.

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 prior to the 2014 Plan in order to more accurately match supply with load.[108] The history of the IPA administered procurements is available on the IPA website.[109] The 2016 Procurement Plan includes procurement of energy supply to meet the needs of MidAmerican's eligible customers as well as those of ComEd and Ameren Illinois. These purchases are driven by the supply requirements outlined in the current year procurement plan and are executed through a competitive procurement process by the IPA's Procurement Administrator. This procurement process is monitored for the Commission by the independent Procurement Monitor.

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 2016-2017 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 2016-2017 delivery year. A portion of the targeted hedge levels for the 2017-2018 and the 2018-2019 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 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 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. [110]

Due to the forecasted return of some load to the utilities, curtailment of the LTPPAs is highly unlikely for the 2016-2017 delivery year for ComEd and Ameren Illinois. 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., although not procured by the IPA, were directed by the Commission order approving the

[108] IPA 2014 Procurement Plan at 93.
[109] http://www2.illinois.gov/ipa/Pages/Prior_Approved_Plans.aspx.
[110] P.A. 97-0616 also mandated associated REC procurements, but these REC procurements do not impact the (energy) resource portfolio.

Agency's 2013 Procurement Plan.[111] In February 2015, DOE funding support for Future Gen 2.0 was suspended, potentially eliminating the project as a source of supply.

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.

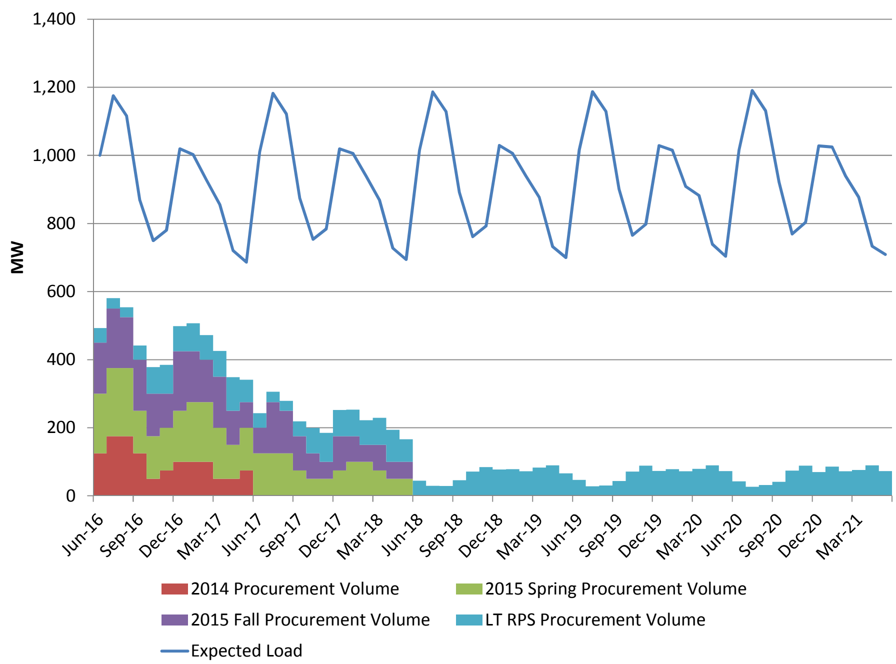
4.1 Ameren Illinois Resource Portfolio

Figure 4-1 shows the current supply gap in the Ameren Illinois supply portfolio for the five-year, June 2016 through May 2021, planning period, using the expected 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 2016-2017 delivery year. Additional energy supply will be required for the entire 5-year planning period. Approximately 58% of the Ameren Illinois residential load has switched to ARES suppliers. The Ameren Illinois expected 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 2016-May 2021 Period - Expected Load Forecast



Under the expected load forecast scenario, the average supply gap for peak hours of the 2016-2017 delivery year is estimated to be 456 MW, the peak period average supply gap for the 2017-2018 delivery year is estimated to be 686 MW, and the average peak period supply gap for the 2018-2019 delivery year is estimated to be 857 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.

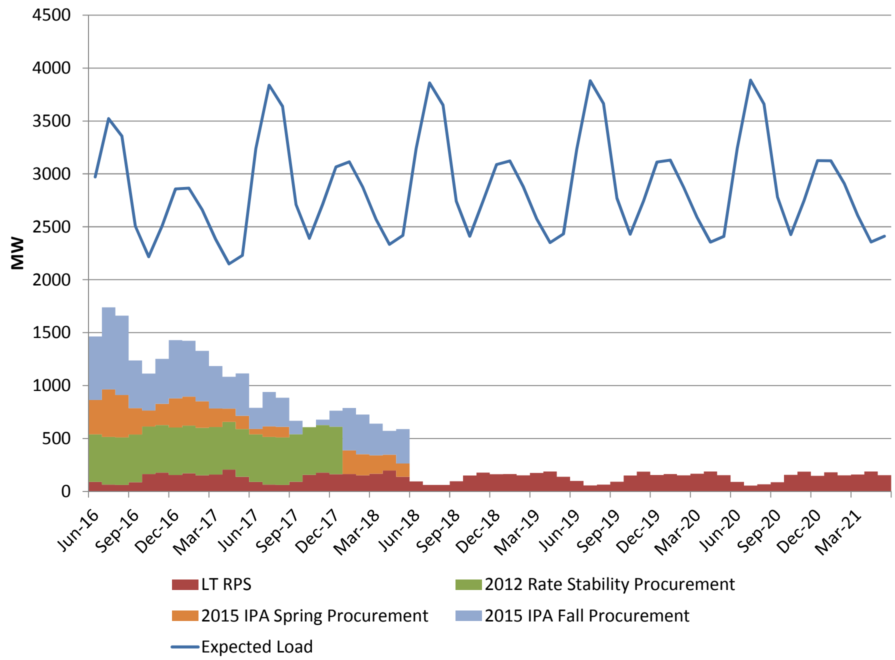
[111] Docket No. 12-0544, Final Order dated December 19, 2012 at 228-237; see also Docket No. 13-0034, Final Order dated June 26, 2013 ("Phase II" approving sourcing agreement as required in Docket No. 12-0544).

4.2 ComEd Resource Portfolio

Figure 4-2 shows the current gap in the ComEd supply portfolio for the June 2016-May 2021 planning period, using the expected load on-peak forecast described in Chapter 3.

ComEd's current energy resources will not cover load starting in June 2016. The average supply gap during peak hours for the 2016-2017 delivery year under the expected load forecast is estimated to be 1,350 MW. The average supply gap during peak hours for the 2017-2018 and 2018- 2019 delivery years are estimated to be 2,189 MW and 2,789 MW respectively.

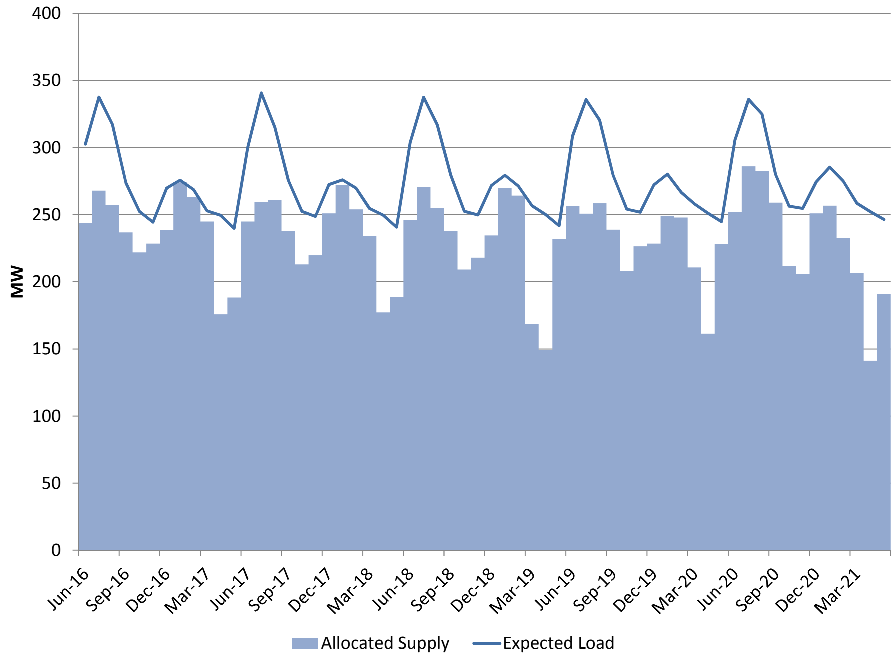
Figure 4-2: ComEd's On-Peak Supply Gap - June 2016-May 2021 period - Expected Load Forecast



4.3 MidAmerican Resource Portfolio

Figure 4-3 shows the current supply gap in the MidAmerican supply portfolio for the five-year planning period, using MidAmerican's expected on-peak load forecast. 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 load is served by a 10.86% allocation of capacity from MidAmerican's historical Illinois resources. The average supply gap during peak hours for the 2016-2017 delivery year under the expected load forecast is estimated to be 41 MW. The average supply gap during peak hours for the 2017-2018 delivery year is 43 MW and for the 2018-2019 delivery year the supply gap is 49 MW.

Figure 4-3: MidAmerican's On-Peak Supply Gap - June 2016-May 2021 period - Expected Load Forecast



4.4 Allocation of Supply Volumes Associated with Ameren Illinois and ComEd LTPPAs

The IPA's approved 2012 Procurement Plan prescribed for each utility an average monthly peak and off-allocation of the LTPPAs' annual contract energy volume. The IPA's prescribed allocation covered the period of June 2012 through May 2015. In 2016 Procurement Plan, again for procurement planning purposes, the IPA proposes an extension of the monthly allocation through May 2032. For illustration purposes, Table 4-1 and Table 4-2 show the proposed allocation for the 2015-2016 Planning Year for Ameren Illinois and ComEd respectively. Appendices E and F show the entire proposed allocations. The methodology for establishing the proposed allocations is the same that was used in the 2012 Procurement Plan.

Table 4-1: Ameren Illinois LTPPAs Monthly Peak and Off-Peak Allocations (June 2015 through May 2016)

Month	Monthly Peak Hours	Peak Renewable Energy Volumes (MWh)	Average Monthly Peak Load (MW)	Monthly Off Peak Hours	Off Peak Renewable Energy Volumes (MWh)	Average Monthly Off Peak Load (MW)
June-16	352	15,084	43	368	19,369	53
July-16	320	9,802	31	424	15,538	37
August-16	368	10,605	29	376	19,550	52
September-16	336	13,957	42	384	19,209	50
October-16	336	26,207	78	408	32,150	79
November-16	336	28,412	85	384	37,229	97
December-16	336	24,720	74	408	28,286	69
January-17	336	27,529	82	408	33,620	82
February-17	320	23,116	72	352	27,944	79
March-17	368	27,862	76	376	37,611	100
April-17	320	31,530	99	400	35,950	90
May-17	352	23,352	66	392	31,368	80

Table 4-2: ComEd LTPPAs Monthly Peak and Off-Peak Allocations (June 2015 through May 2016)

Month	Monthly Peak Hours	Peak Renewable Energy Volumes (MWh)	Average Monthly Peak Load (MW)	Monthly Off Peak Hours	Off Peak Renewable Energy Volumes (MWh)	Average Monthly Off Peak Load (MW)
June-16	352	31,720	90	368	40,731	111
July-16	320	20,613	64	424	32,675	77
August-16	368	22,301	61	376	41,112	109
September-16	336	29,350	87	384	40,394	105
October-16	336	55,110	164	408	67,607	166
November-16	336	59,747	178	384	78,287	204
December-16	336	51,982	155	408	59,481	146
January-17	336	57,891	172	408	70,699	173
February-17	320	48,610	152	352	58,762	167
March-17	368	58,588	159	376	79,093	210
April-17	320	66,303	207	400	75,599	189
May-17	352	49,107	140	392	65,962	168

5 MISO and PJM Resource Adequacy Outlook and Uncertainty

As a result of retail choice in Illinois, resource adequacy (the load/resource balance) can be viewed as a function of determining what level of resources to purchase from which markets over time. 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 of all customers reliably. This Section reviews the likely load/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/resource outcomes over the planning horizon, this Section analyzes several outside studies of resource adequacy that are publicly available from different planning and reliability entities. These 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.
- PJM Interconnection ("PJM"), which operates the transmission grid in Northern Illinois.

From review of these entities' most recent 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 may be short resources starting in the 2016-2017 timeframe.

5.1 Resource Adequacy Projections

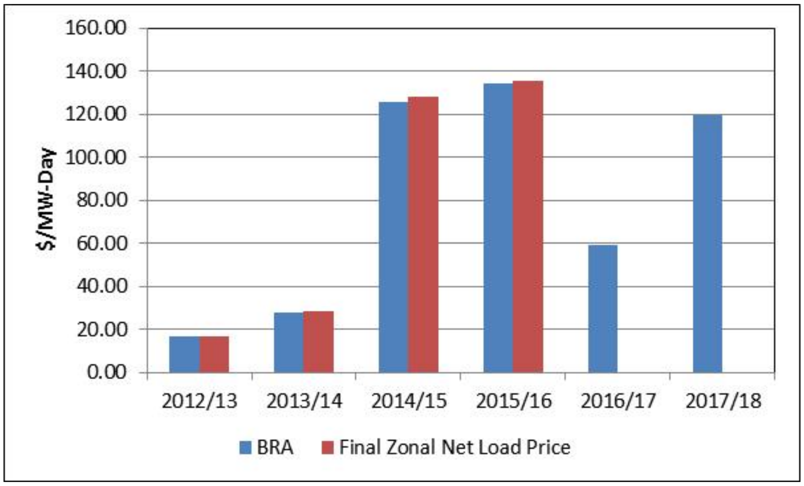
In PJM, capacity is largely procured through PJM's capacity market, the Reliability Pricing Model ("RPM"), which was approved by FERC in December 2006.[112] RPM is a forward capacity auction through which generators offer capacity to serve the obligations of load-serving entities. The primary capacity auctions, Base Residual Auctions ("BRAs"), are held each May, three years prior to the commitment period.[113] The commitment period is also referred to as a Delivery Year.[114] In addition to the BRAs, up to three incremental auctions are held, at intervals 20, 10, and 3 months prior to the Delivery Year. The 1st, 2nd, and 3rd Incremental Auctions are conducted to allow for replacement resource procurement, increases and decreases in resource commitments due to reliability requirement adjustments, and deferred short-term resource procurement. 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 Delivery Year.

Just prior to the beginning of each Delivery 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 determined based on the results of the BRA and subsequent incremental auctions for a given Delivery Year. As the procurement of the majority of the capacity via the RPM is done during the BRA, there is little variation

[112] 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 will be implemented for the 2018-2019 delivery year, with a transition mechanism for the 2016-2017 and 2017-2018 delivery years that will facilitate improved resource performance during those years by allowing a portion of capacity to be rebid in a new procurement. The capacity performance incentives will most likely result in increases in the capacity prices.
[113] Note that the BRA for the 2018-2019 delivery year was delayed from May, 2015 to August, 2015.
[114] A Delivery Year is June 1 through May 31 of the following year.

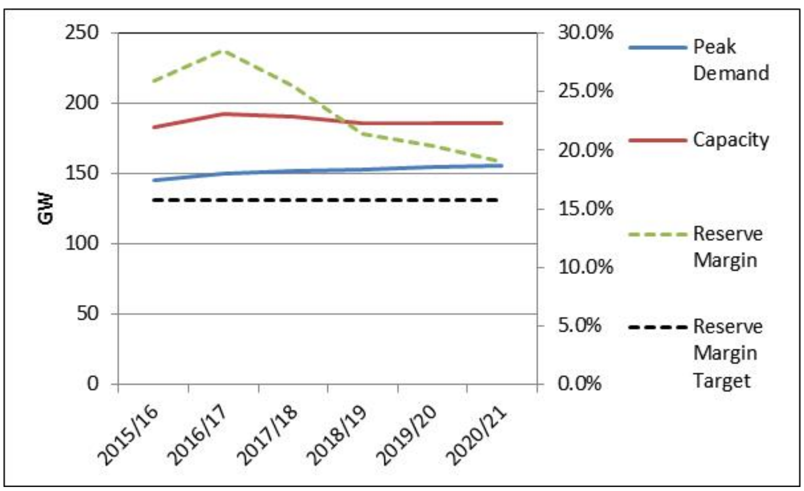
between the BRA clearing price and the Final Zonal Net Load Price as shown in Figure 5-1. However, the results of the incremental Capacity Performance auctions expected out in late August and early September may significantly change the net price of capacity for the 2016-2017 and 2017-2018 delivery years.

Figure 5-1: PJM RPM Capacity Price for Delivery Years 2012-2017[115]



As shown in Figure 5-2, PJM is projected to have sufficient resources to meet load plus required reserve margins for the Delivery Years 2015-2020, with projected reserve margins above the 15.7% target reserve margin. For the 2015-2016 Delivery Year, the reserve margin is approximately 10% above the target reserve margin, dropping to approximately 3% above the target reserve margin for the 2020-2021 Delivery Year.

Figure 5-2: PJM NERC Projected Capacity Supply and Demand for Delivery Years 2015-2020



Source: NERC 2014 Long Term Reliability Assessment ("NERC 2014 LTRA")[116]

[115] 2015-2016 is the latest Delivery Year for which the Final Zonal Net Load Price has been calculated. It will be calculated for future Delivery Years as the start of the year approaches. The 2018-2019 PJM BRA was postponed due to the delayed FERC decision on PJM's Capacity Performance Filing. On June 9, 2015 FERC issued an Order accepting, subject to compliance filing, PJM's Capacity Performance Filing. PJM submitted the compliance filing on July 9, 2015. The BRA results are now expected to be posted on August 21, 2015.

MISO's Resource Adequacy construct, specified in Module E-1 of its Tariff,[117] 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")[118] for the Planning Year.[119] 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 third PRA are provided in Section 5.2.

As shown in Figure 5-3, based upon the NERC 2014 LTRA, on a region-wide basis MISO is expected to have sufficient resources to meet load plus required reserve margin for the 2015-2016 Planning Year with a reserve margin slightly above 17% which is approximately 2% above the reserve margin target of 14.8%. However, starting with the 2016-2017 Planning Year through the 2020-2021 Planning Year MISO is projected to have insufficient resources to meet load plus required reserve margin. The 2016/17 shortfall is approximately 2% and increases to approximately 5% in 2020-2021. As also shown in Figure 5-3, NERC's analysis mirrors MISO's analysis presented in the 2014 MISO Transmission Expansion Planning ("MTEP") report, which addresses resource adequacy. The MISO reserve margin estimates are slightly higher than the NERC estimates. In the resource adequacy Section of the 2014 MISO MTEP, MISO explains the difference as follows: "When comparing reserve margins between Table 6.2-1 and the NERC LTRA, the percent for each planning year will be slightly lower in the NERC LTRA because of the differences in how the reserve margin percent is calculated. MISOs Resource Adequacy construct counts DR as a resource while the NERC calculation has the DR calculated on the demand side. While the percent will be slightly different, the absolute GW shortfall/surplus is the same between the two."

Both NERC and MISO explain the drop in reserve margin beginning in 2016 in similar terms. In this regard the primary contributing factors driving the projected shortfall are:

- Increased retirements and suspensions due to Environmental Protection Agency ("EPA") regulations and market forces (i.e. low natural gas prices);
- Exclusion of low certainty resources that were identified in the Resource Adequacy survey;[120]
- Increased exports to PJM and the removal of non-Firm imports;[121]
- Exclusion of surplus capacity in MISO South above the 1,000 MW transfer limit;[122]
- Not enough certainty of resources planned; 91 percent of the load in the MISO footprint is served by utilities with an obligation to serve customers reliably and at a reasonable cost. Resource planning and investment in resources are 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").

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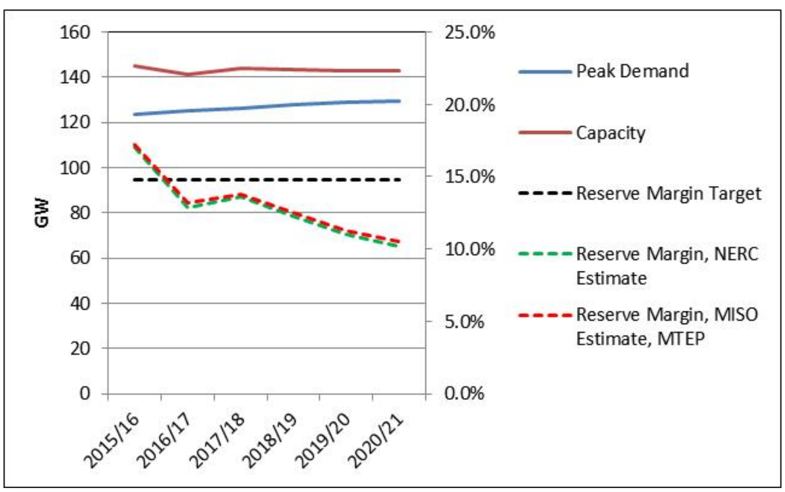
[116] Prior Procurement Plans have relied on the data from the Electricity Supply & Demand Database ("ESD"). In discussions with a NERC representative regarding data from the ESD, the representative recommended using data from the recently published NERC 2014 LTRA which provides the pertinent data on Peak Demand, Reserve Margin and Reserve Margin Target.
[117] 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.
[118] 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.
[119] A Planning Year is June 1 through May 31 of the following year.
[120] The Resource Adequacy survey of LSEs was conducted by MISO and the Organization of MISO States ("OMS") with the goal of providing an updated view into the long-term resource situation. Resources that were identified to have a low certainty of serving load were not included in the assessment.
[121] Capacity sales (imports and exports) in MISO depend on the decisions of the respective resource owners, assuming that the tariff requirements are met. Regarding the removal of non-Firm imports, the MISO market monitor notes that MISO was double-counting non-firm imports because the PRMR already includes the use of non-firm imports.
[122] For this assessment 1,000 MW of capacity is transferred from the MISO South to the MISO North/Central Region pending the outcome of the regulatory issues currently under FERC review.

In light of the projected reserve margin deterioration, MISO is studying ways to better utilize existing transmission and generation to help alleviate the expected near-term shortages. One strategy to alleviate the potential capacity shortfalls is to convert generation capacity that is currently ineligible to qualify as Planning Resources in the annual PRA. In this regard, MISO is conducting the Unused Generation Capacity Study that seeks to identify and inform Market Participants of potential opportunities to participate in the capacity market by connecting to the grid as Network Resources. Preliminary results from the study indicate that approximately 806 to 938 MW of generation have the potential to become Network Resources with no required network upgrades after progressing through the MISO Generation Interconnection Process. An additional 273 to 404 MW will require network upgrades to unlock the constrained unused generation. With the completion of the study, projects will be identified that would allow resources to qualify as Planning Resources, eligible for participation in the PRA. Similarly, MISO has undertaken the South to North/Central Capacity Transfer Analysis, which explores ways to improve the transfer capacity between the regions. The transfer analysis identified the full capability of the transmission system to be in the 3 to 4 GW range; an increase of 2 to 3 GW from the level of capacity that was counted from MISO South in the 2014-2015 and 2015-2016 PRAs.[123] As noted earlier the current assessment assumes a maximum of 1,000 MW of MISO Region capacity is available to MISO North/Central Region. The Unused Generation Capacity Study and the South to North/Central Capacity Transfer Analysis help to inform areas where additional capacity could potentially clear and help mitigate potential Resource Adequacy shortfalls.

The NERC analysis notes that although the reserve margin is projected to fall below the reserve margin target in 2016, MISO fully expects that the shortfall will change significantly once LSEs and state commissions within the footprint solidify future capacity plans. In this regard, in the 2014 MTEP report, MISO states that "By Planning Year 2016-17 MISO projects that its region will operate at an approximately two-days-in-10 reliability level unless and until Load Serving Entities and State commissions solidify future capacity plans." As such the MISO capacity projection may need to be updated when more reliable data is available.

Figure 5-3: MISO NERC Projected Capacity Supply and Demand for the Planning Years 2015-2020



Source: NERC 2014 Long Term Reliability Assessment, MISO 2014 MTEP Book 2 Resource Adequacy

[123] On March 28, 2014, FERC accepted for filing, and suspended for a nominal period to be effective January 29, 2014, subject to refund and hearing and settlement judge procedures, a Transmission Service Agreement filed by Southwest Power Pool ("SPP"), requiring MISO to pay SPP for any flow on SPP's transmission system above the existing 1,000 MW contract path between MISO North/Central and MISO South. This contract path limitation is currently being litigated before FERC.

5.2 Locational Resource Adequacy Needs

A key component of the Module E-1 RAR is the establishment of Local Resource Zones ("LRZs"). The MISO region currently has 9 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")[124] 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 third PRA in April 2015.

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. While the IPA concludes that it does not need to include any extraordinary measures in the 2016 Procurement Plan to assure reliability over the planning horizon, the IPA acknowledges the results of the 2015-2016 MISO PRA which cleared substantially higher for the Illinois Region (Zone 4) than in prior years. A discussion of the results follows.

In the 2014-2015 PRA, Zone 1 cleared at $3.29/MW-Day, Zones 2-7 cleared at $16.75/MW-Day, and Zones 8-9 cleared at $16.44/MW-Day.[125] In the 2015-2016 PRA, Zones 1, 2, 3, 5, 6, and 7 all cleared at $3.48/MW-Day and Zones 8-9 cleared at $3-29/MW-Day. Zone 4 (IL) on the other hand cleared substantially higher at $150/MW-Day.[126] As shown in Figure 5-4 the Zone 4 price is 9 times greater than the previous Planning Year, and more than 40 times greater than the other zones, which has raised questions from consumer advocates, the Illinois Attorney General, and industrial customers. In its efforts to better understand the results of the 2015-2016 PRA, in particular as they relate to Zone 4, the IPA reviewed presentations and statements made by MISO and MISO's Independent Market Monitor ("MISO IMM") on the auction.

In a presentation that was made to the MISO's Supply Adequacy Working Group ("SAWG"),[127] MISO noted that the 2015-2016 PRA results indicate adequate resources in the region for the Planning Year. MISO further explained that Zone 4 cleared at a higher price because of higher incremental cost of capacity in the zone, noting that to meet the local resource requirement in the zone,[128] this higher priced capacity was needed and therefore set the price for the zone. In their presentation, MISO also noted that the MISO IMM reviewed the auction results for physical and economic withholding and concluded that the submitted offers represented a competitive market outcome.

In response to questions raised by the Illinois Attorney General,[129] MISO noted that:

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

[125] The MISO LRZs encompass the following states: Zone 1 (MN, ND, Western WI), Zone 2 (Eastern WI, Upper MI), Zone 3 (IA), Zone 4 (IL), Zone 5 (MO), Zone 6 (IN, KY), Zone 7 (MI), Zone 8 (AR), Zone 9 (LA, MS, TX). In 2013 MISO integrated Entergy into MISO creating the MISO South Region (Zones 8-9).

[126] MISO also calculated the Zonal Deliverability Benefit ("ZDB"). ZDBs occur when constraints cause price separation resulting in over-collection of auction revenues in importing zones or groups of zones. Per the MISO Tariff, the ZDB for 2015-2016 will be a credit of $23.47/MW-Day to load in Zone 4.

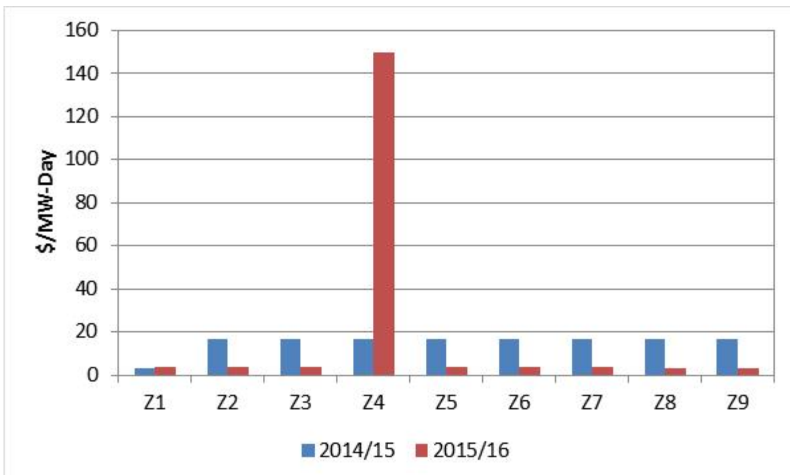
[127] The presentation can be found at: https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/SAWG/2015/20150430/20150430%20SAWG%20Item%2002%20ab%202015-16%20PRA%20Summary.pdf.

[128] The zonal capacity requirement must be met with Resources located within the zone.

[129] The response can be found at: http://www.rtoinsider.com/wp-content/uploads/MISO-response-to-IL-OAG-4-24-15.pdf

(i) Incremental changes which had been made to the Tariff effective for the 2015-2016 Planning Year either did not impact Zone 4, or they impacted Zone 4 no more or less than other LRZs within the MISO region.
(ii) There were no specific design or PRA rule changes that specifically addressed conditions unique to Zone 4.
(iii) While Zone 4 was able to import 1,568 MW[130] of lower cost capacity from other zones, the balance of the capacity for the zone needed to come from resources internal to Zone 4 (the LCR).
(iv) The rules were followed in the 2015-2016 PRA. In Zone 4, higher priced local resources were needed to meet the LCR. Additionally, more capacity was procured through the 2015/16 PRA rather than by direct contracts between parties as compared to the previous year, resulting in more exposure to price sensitive capacity offers in the 2015-2016 PRA.
(v) Some differences in offers and bidding strategies occurred in the 2015-2016 PRA as compared to previous years. The MISO IMM reviewed the offers and determined that the final results were not impacted by physical or economic withholding or other conduct prohibited by the MISO's Tariff.

Figure 5-4: MISO PRA Results for Planning Years 2014-2015 and 2015-2016



In a presentation that was made to the MISO's SAWG,[131] the MISO IMM noted that:

(i) The 2015-2016 PRA was conducted and cleared in accordance with the Tariff.
(ii) No market power mitigation was warranted.
(iii) There were no conduct failures for economic withholding in Zone 4 based on the Reference Level.[132]
   a. The Reference Level must reflect suppliers' competitive options, including retiring / mothballing and exporting capacity to neighboring regions.
      i. The opportunity to retire is based on a supplier's "going forward costs".
      ii. The opportunity to export is based on prices in neighboring markets.
   b. The best opportunity for exporting capacity is the PJM market.
   c. The Initial Reference Level for Zonal Resource Offers was $155.79/MW-Day.

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[130] MISO's presentation of the 2015-2016 PRA explaining the ZRC clearing shows that 568 MW were imported from Zones 1-3 & 5-7 (net ZRC surplus) and the remaining 1,000 MW was imported from Zones 8 &9 (MISO South).

[131] The presentation can be found at: https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/SAWG/2015/20150430/20150430%20SAWG%20Item%2002c%20IMM%20on%202015-16%20PRA%20Results.pdf.

[132] Reference Levels serve as Benchmarks used in performing Conduct Tests.

   i. This is calculated as the PJM penalty price (based on clearing prices in PJM) minus the transmission expenses to deliver to PJM.

d. The latest market data in the IMM's possession prior to the PRA validated the Reference Level.
   i. The PJM RPM 3rd Incremental Auction cleared almost exactly at the penalty price calculated by the IMM ($163.20 vs. $163.41) / MW-Day
   ii. Subtracting $7.63/MW-Day in transmission costs yields $155.57/MW-Day, nearly matching the IMM's Initial Reference Level.

e. If the IMM does not find bilateral data and uses the same methodology next year, the Initial Reference Level will be roughly $71/MW-Day.

The IPA also notes that four complaints have been filed at FERC against MISO regarding the results of the 2015-2016 MISO PRA in Zone 4. The complaints were filed by the Illinois Attorney General ("IL AG")[133], Public Citizen, Inc ("Public Citizen")[134], Southwestern Electric Cooperative ("SWEC")[135] and the Illinois Industrial Energy Consumers ("IIEC")[136]. The complaints can be summarized as follows:

- The IL AG takes issue with the substantial increase in the Zone 4 clearing price from $16.75/MW-Day to $150/MW-Day, an increase of close to 900% from the 2014-2015 auction result. The IL AG also alleges that Dynegy is a Pivotal Supplier in Zone 4 because its participation in the PRA is required to meet the reliability standard set by MISO. The IL AG further alleges that Dynegy was able to structure its bids such that they would set the zone's clearing price based on the requirement to meet the LCR. The IL AG also further alleges that the 2015-2016 MISO PRA for Zone 4 failed to address the market power of the Pivotal Supplier in the Zone, resulting in the pivotal supplier exercising anti-competitive market power and driving the capacity price in Zone 4 to a level that is not just and reasonable and above that supplier's internal cost. In their requested relief the IL AG asks FERC to (i) find that the rate resulting from the 2015-2016 PRA for Zone 4, effective June 1, 2015 is not just and reasonable, (ii) suspend the rate resulting from the 2015-2016 MISO PRA for Zone 4, effective June 1, 2015, (iii) institute a proceeding to investigate the allegations raised in the complaint, and if it does not suspend the rates as requested, establish a refund date, (iv) set new rates for the 2015-2016 PRA for Zone 4, (v) assign the issues to a settlement process with a deadline for resolution of 60 days if FERC declines to find the rates to be unjust and unreasonable, and if settlement is not successful, set the matter for discovery and evidentiary hearing, (vi) direct MISO to amend its Tariff governing the PRA to protect consumers from the exercise of market power by pivotal suppliers, (vii) assess civil penalties if it concludes in this proceeding or and other proceeding or investigation that market manipulation by any party led to the unjust and unreasonable rates resulting from the 2015-2016 PRA for Zone 4, and (viii) enter a Supplemental Order in Docket EC13-93-000, imposing appropriate conditions on Dynegy with regard to bidding behavior by the Ameren Generators (now controlled by Dynegy) in the annual MISO Zone 4 PRAs.

- Public Citizen alleges that the highly excessive, unjust, unreasonable, and unduly discriminatory rate increases for MISO's Zone 4, may be the result of illegal manipulation and gaming of the auction bidding process, specifically capacity withholding. Public Citizen alleges that Dynegy may have engaged in intentional capacity withholding to drive auction prices from $16.75/MW-Day to $150.00/MW-Day. Public Citizen further alleges that utilities like Dynegy use the threat of "ISO Shopping" as a lever to influence the development of market rules that protect their profitability (or to prevent changes in the rules that would limit their ability to exercise market power) and MISO, acting out of a sense of self-preservation, has incentive to acquiesce to such threats in order to retain membership. Public Citizen requests that (i) FERC exercise its authority under FPA Section 206 to institute an emergency investigation into whether PRA was manipulated by illegal practices under FPA Section 222 so that the rates resulting therefrom, especially as to MISO Zone 4, are unjust and unreasonable, or unduly

[133] FERC Docket EL15-71-000.
[134] FERC Docket EL15-70-000.
[135] FERC Docket EL15-72-000.
[136] FERC Docket EL15-82-000.

discriminatory, and to set a refund effective date as of the effective date of this Complaint; and that (ii) FERC exercise its authority under FPA Sections 205(d) and 309 to require that the MISO file as soon as possible the results of the PRA as a Section 205 filing of increased rates for MISO Zone 4, and any other MISO Zone in which changed charges are proposed, and to set such rates for hearing under FPA Section 205(e) with the burden of proof on MISO to justify the increases, and to suspend such rates for at least one day and make them subject to refund.

- SWEC alleges that the 2015-2016 PRA failed to produce just and reasonable rates in Zone 4 as a result of a non-competitive auction, noting (i) the staggering increase from the 2014-2015 auction clearing price of $16.75/MW-Day to the 2015-2016 auction clearing price of $150.00/MW-Day and (ii) the incredible disparity between the results of Zone 4 (at $150.00/MW-Day) and the other MISO Zones (with the next highest zone clearing at $3.48/MW-Day). SWEC seeks an order that (i) finds the results of the MISO 2015-2016 PRA for Zone 4 to be unjust, unreasonable, and unduly discriminatory; (ii) sets a just, reasonable, and non-discriminatory price for the procurement of capacity in Zone 4; (iii) directs MISO to submit for FERC approval tariff revisions that will prevent a single market participant from exercising market power in future MISO Zone 4 PRAs; and (iv) initiates an investigation into whether Dynegy's actions leading up to the 2015-2016 PRA resulted in market manipulation in contravention of Federal Power Act Section 222 and FERC regulations.

- IIEC's complaint is that certain terms and conditions of the MISO Tariff relating to the PRA are no longer just and reasonable in light of the MISO 2015- 2016 auction results for MISO Zone 4. IIEC requests FERC acceptance of specific tariff modifications to ensure these deficiencies are fully addressed prior to MISO conducting its 2016-2017 Auction. IIEC also takes issue with the fact that MISO's 2015-2016 auction resulted in an auction clearing price of $150.00 per MW-day for Zone 4 which is a 655% increase from the 2014-2015 price for capacity of $16.75 per MW-day for Zone 4 after adjusting for the MISO 2015-2016 PRA Zonal Delivery Benefit credit for Zone 4 of $23.47 per MW-day. IIEC seeks a FERC order (i) finding that MISO's calculation of LCRs in its PRA and the MISO IMM's calculation of lost opportunity cost for Reference Level Prices for the MISO PRA are unjust and unreasonable; and (ii) directing MISO to modify the LCR and PRA Reference Level calculations under the MISO Tariff prior to conducting the MISO 2016-2017 PRA to ensure that LCRs, Reference Levels, and Conduct Threshold Levels are justly and reasonably calculated for the 2016-2017 and future MISO PRAs.

The ICC submitted comments in the respective dockets. In their comments the ICC notes that if the PRA results are found to result in rates that are unjust and unreasonable, FERC should order appropriate refunds. Regardless, the ICC suggests that FERC should direct MISO to work with its stakeholders, in an expeditious manner, to re-examine certain design elements of the MISO PRA and to submit tariff changes prior to the 2016 PRA to ensure that the 2016 PRA, and future PRAs, produce just and reasonable capacity prices. The ICC notes that the design elements at issue include: (1) reference levels; (2) LCRs; and (3) LRZ configuration. Specifically, FERC should reexamine the effectiveness of MISO's current method for calculating the reference level as a means to mitigate market power, particularly in the presence of a pivotal supplier. The ICC acknowledges the role that LRZs play with respect to reliability. However, the ICC notes that LRZ 4 bound on the LCR rather than the capacity import, which directly impacted the clearing price by limiting the volume of lower cost generation that could be imported into LRZ 4 to meet its reliability requirement. Such an occurrence suggests that there is an inconsistency in the relationship between the LCR, the CIL and the role these parameters play in achieving MISO's stated reliability goals within each LRZ. Accordingly, the ICC notes that FERC should reexamine how MISO develops these zonal auction parameters, how MISO implements them in the PRA, how they impact the PRA clearing prices for each LRZ and order MISO to correct any existing design flaws. Finally, given the results of the 2015-2016 PRA, and the increasing strength of the interconnection between LRZs 4 and 5, FERC should direct MISO to consolidate LRZs 4 and 5. Consolidating the two LRZs, notes the ICC, would dilute the ability of a pivotal supplier to exercise market power.

In response to the complaints, MISO notes that it followed its FERC-accepted, Tariff-based rules and its IMM confirmed that the PRA both complied with the Tariff and produced the results it should have produced. Although MISO followed its Tariff, the auction produced higher prices than previously experienced in Zone 4.

MISO states that the fact the latest Zone 4 PRA clearing price is higher than the PRA Zone 4 results in prior auctions does not establish that the price is unjust and unreasonable; or that the price was the product of any lack of oversight or administration on MISO's part; or that the price was the product of market manipulation, all as alleged by Complainants. That the price is higher also does not establish that MISO violated any rules concerning the conduct of the auction, and none of the complaints makes such an allegation. MISO further notes that it conducted the auction exactly as required under its Tariff, and none of the Complainants provide any evidence to the contrary. Accordingly, MISO notes that these complaints should be dismissed with prejudice.

MISO and IMM claim that the 2015-2016 PRA worked as expected and the final results were not impacted by physical or economic withholding and other conduct prohibited by MISO's Tariff. The review also suggests that for the 2016-2017 and 2017-2018 PRAs, Zone 4 will clear in a similar fashion to the 2015-2016 PRA with the Zone 4 price most likely tracking the Initial Reference Price. With the IMM forecasting a $71/MW-Day Initial Reference Price for 2016-2017 and a Preliminary Initial Reference Price of $136.37/MW-Day[137] for 2017-2018 it is conceivable that the Zone 4 price will clear at close to these prices, i.e. dropping in 2016-2017 then rising again in 2017-2018. While the PJM Base Residual Auction (BRA) for 2018-2019 has not been conducted yet due to the delayed FERC decision on PJM's Capacity Performance Filing, the capacity performance incentives will most likely result in an increase in the BRA price for 2018-2019.[138] With the MISO IMM using the opportunity cost of selling to PJM as a basis for deriving the Initial Reference Price it is safe to assume that the Initial Reference Price for 2018-2019 will be higher. In light of the complaints and the facts surrounding the 2015-2016 PRA, the IPA expects much uncertainty in future MISO PRA Zone 4 clearing prices. In the interest of hedging price risk and maintaining rate stability for the Illinois customers, the IPA recommends hedging a portion of Ameren's capacity market exposure for the upcoming planning years as described in Section 7.4.

[137] Forecast based on RPM BRA results for 2017-2018 and presented at February 5, 2015 SAWG.

[138] On June 9, 2015 FERC issued an Order accepting, subject to compliance filing, PJM's Capacity Performance Filing. PJM submitted the compliance filing on July 9, 2015. The BRA results are now expected to be posted on August 21st, 2015.

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."[139]

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.*[140]

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 6.2 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 6.3 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.

Sections 6.4 through 6.6 address 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").[141] The energy pricing for MidAmerican customers in Illinois is currently regulated by the Illinois Commerce Commission. Section 6.4 provides a historical summary of PEA rates as a guide to the historical impact of risk factors. Section 6.5 discusses the IPA's historical approach to risk and portfolio management, and briefly discusses the risk of winter price spikes such as occurred in 2014. Finally, Section 6.6 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.

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

[139] 20 ILCS 3855/1-20(a)(1).
[140] 220 ILCS 5/16-111.5(b)(3)(vi).
[141] See 220 ILCS 5/16-111.5(l). This policy is manifest through riders filed by each utility – ComEd's Rider PE (Purchased Electricity), and Ameren Illinois' Rider PER (Purchased Electricity Recovery).

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 eligible customers to take service from ARES or through municipal aggregation resulted in substantial portions of the eligible retail load switching away from the utilities for non-utility retail contracts that run through the 2014-2015 procurement year. More recently, the primary uncertainty surrounding customer switching appears to be the potential for significant 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 will be obtained through the IPA's procurement process starting with the 2016 procurement year. 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 the 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 customers migrating away from the utilities.

6.1.3 Hedging Imperfections

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. Locational mismatches are generally not a significant risk for the IPA procurements since the delivery points for the hedge contracts are the Load Serving Entity's ("LSE's") load zone. 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.

6.2 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 QF (Qualifying Facilities under the

Public Utilities Regulatory Practices Act ("PURPA")) contracts. Their long-term renewables Power Purchase Agreements ("LTPPAs") are structured as "Contracts for Differences." 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 eligible Illinois customers. Under the 2016 Procurement Plan, the IPA will procure the net requirements between MidAmerican's eligible customer retail 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.

6.2.1 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.[142]

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

6.2.1.1 Unit-Specific Hedges

- As-available
- Baseload
- Dispatchable

6.2.1.2 Unit-Independent Hedges.

- Standard forward hedges (block contracts)
- Shaped forward hedges

[142] 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 customers.

- Futures contracts
- Options
- Full requirements hedges

6.2.2 Suitability of Supply Hedges

Not all of the types of hedges listed in Section 6.2.1 are suitable for use in this Procurement Plan, and not all may be readily available in electricity markets.[143] 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.[144] 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.[145] The most natural evidence of competitiveness will be 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 mid-year 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 product" in its approval of the 2014 Procurement Plan, the IPA's authority to procure other products, including shaped forward contracts and option contracts, could be subject to future litigation. Markets for products that are specifically designed for the IPA's requirements, such as full requirements contracts or over-the-counter options, will likely have limited transparency. The IPA's procurement structure requires a benchmarking and approval process 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 are traded in reasonably liquid markets, making such contracts easier to benchmark. The markets for long-dated (*i.e.* further in the future) contracts are less liquid, 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-

[143] 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. The IPA is not aware of any new arguments in favor of full requirements, let alone new arguments supported by analyses quantifying benefits to eligible retail customers, and notes the continued success of its procurement approach in producing highly competitive service rates for Ameren Illinois and ComEd eligible retail customers.

[144] 220 ILCS 5/16-111.5(b), (e), (f).

[145] 220 ILCS 5/16-111.5(f).

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, trading in which is more illiquid.

6.2.3 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 spend the money to buy the contract.

Some may perceive options 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 were purely financial and automatic—resulted 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.

6.3 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."[146] 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 mandated rate cap.
- Sales of excess supply by the utilities in the wholesale market 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.[147]
- For the last few years, the utilities have scheduled excess supply in their portfolios, or made up supply deficits, in the RTOs' day-ahead 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 "conduct competitive procurement processes" under 20 ILCS 3855/1-20(a)(2) to sell excess supply.
- 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 more than one procurement event in a year if the rebalancing required is to increase the supply under contract. The IPA conducted two procurements for 2014, and in 2015 after conducting a spring procurement, the Agency is planning a second procurement in September 2015. The volumes for that procurement have been adjusted in this manner.

6.4 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 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's charge for purchased electricity is set by the ICC under a separate cost recovery process.

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 have changed over the last four years. While Ameren Illinois' PEAs have been generally negative, ComEd's

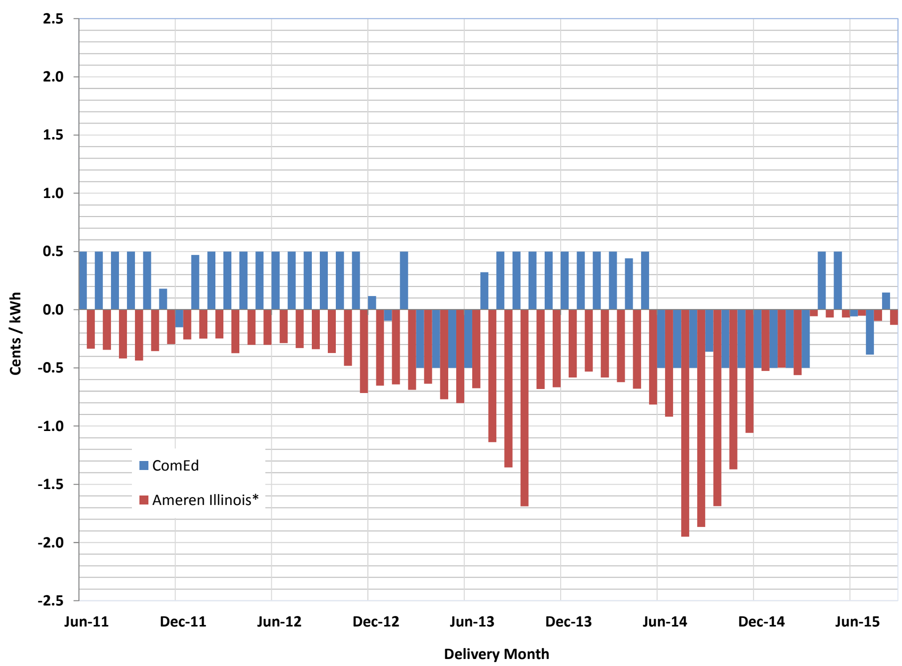
[146] 220 ILCS 5/16-111.5(b)(4).
[147] 125 FERC ¶ 61,064, Oct. 16, 2008.

have been more often than not positive, and have had 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 been a credit in those two months.

In July 2014, the magnitude of the Ameren Illinois negative PEAs increased significantly. The IPA understands that this change was most likely the result of Ameren Illinois over-collection during the previous winter and its PEAs represented the return of these proceeds to customers. The negative values of the Ameren Illinois PEAs have subsequently been much smaller.

Figure 6-1: Purchased Electricity Adjustments in Cents/kWh, June 2011 – August 2015



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

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

6.5.1 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. The Agency suggested that the procurement goal for a mid-April procurement event should be to hedge 106% of the expected load forecast 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. 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 forecast 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.

For the 2016 Procurement Plan, other than moving October from the group of months completed in the April procurement to the group of months completed in the Fall procurement, no substantial changes to the strategy are proposed, but consideration is given to adjusting the cumulative hedge ratios for various delivery months, effective at the next to last scheduled event prior to delivery.

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.

6.5.2 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.

An objective of the procurement schedule is to maximize stability of the resulting rate for service to eligible retail customers, while minimizing cost. If purchases were distributed close to evenly over 5 or 6 events in a 2 to 3 year period, the resulting average price of the portfolio of contracts for any delivery month would reflect an average of any long-term (> 1 year) price trend over the procurement period. The inclusion of several, evenly weighted procurement dates would also smooth out day-to-day volatility in forward prices.

Concentrating a high percentage of purchases for some delivery months in one or two procurement events close to the beginning of the delivery period, however, increases the potential impact of day-to-day market volatility on the portfolio average price.

In general, the IPA expected that the volatility of portfolio price would be reduced by increasing the number of procurement events and allocating purchase targets evenly among them. However, due to the pattern of historical monthly volatilities in the forward market over the time span analyzed, the schedule of procurements prescribed in the 2015 Procurement Plan, which purchases small quantities up to 3 years prior to delivery, produces the lowest volatility of portfolio price as measured by standard deviation. A review of monthly forward market volatilities does not support a strong preference for any particular months of the year as ideal or to be avoided for procurement events. This is to be expected because volatility is driven by market information, which may not have a seasonal profile. The IPA sees no reason, based on this analysis, to significantly change the energy procurement schedule from that established in the 2015 Procurement Plan.

The results of the procurement scheduling and volatility analysis described in more detail later in this Section indicate 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 Figures 6-12 and 6-13 demonstrate 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.

6.5.2.1 Monthly Price Fluctuation

The IPA used historical PJM Northern Illinois hub on peak energy forward prices for trading dates from February 1, 2011 through April 30, 2015 and delivery months from June 2014 through May 2015[148] to analyze the distributions of daily trade prices for individual delivery months over the trading days of each trade month. Results of this analysis are presented in the following charts. Figure 6-2 shows the mean daily prices for the 12 delivery months for each trade month of the sample period, while Figure 6-3 shows the standard deviation of the daily prices for the same distributions. In both charts, the values reported for trade months January 2011 through February 2012 are the same for all 2014 delivery months. Similarly, reported prices begin in March 2012 for 2015 delivery months, but full monthly differentiation is not available until January 2014. Forward prices for July 2014 and August 2014 delivery clearly rose in late 2012 and again in the first six months of 2014, with corresponding spikes in standard deviation at the beginning of those rises. Forward prices for January 2015 and February 2015 delivery rose dramatically in January 2014 and subsequent months with corresponding spikes in standard deviation.

[148] Source of data: Bloomberg LP.

Figure 6-2: Monthly Distribution Means

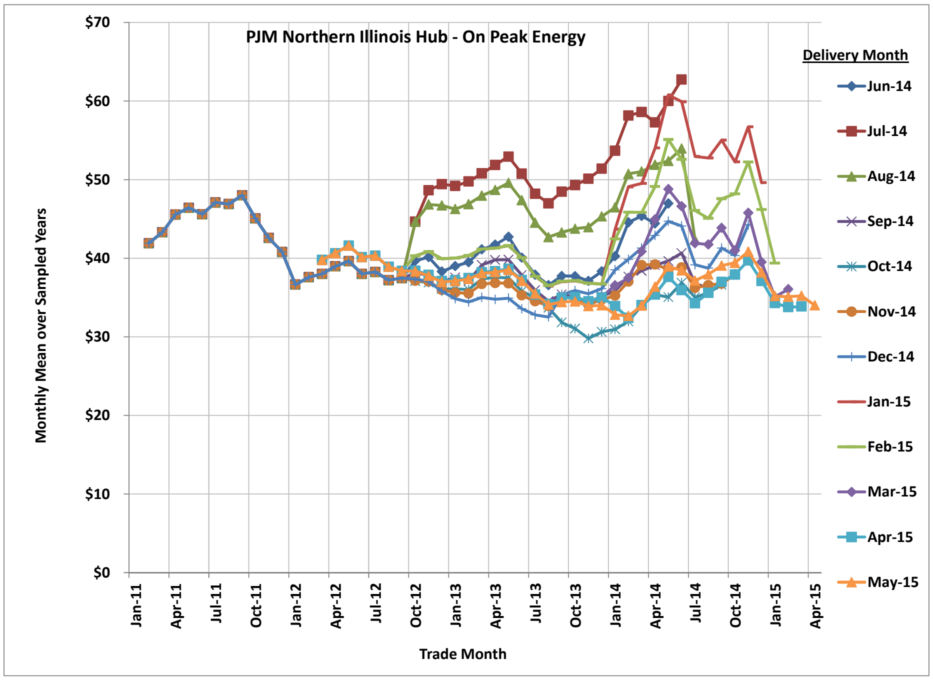
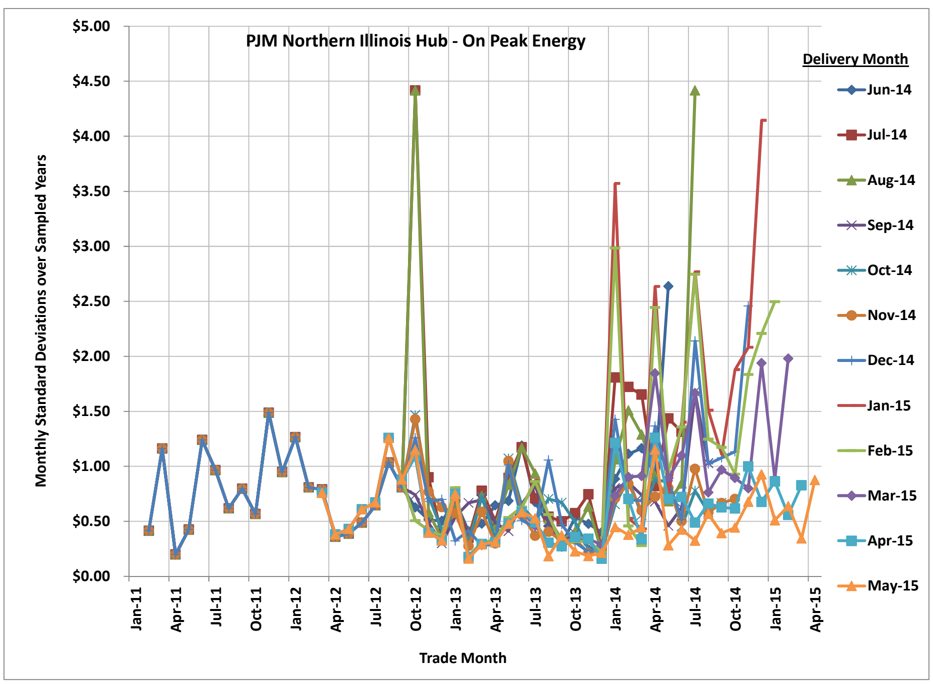


Figure 6-3. Monthly Distribution Standard Deviations



It is helpful to pivot the data for selected delivery months in these charts to see how standard deviation varies by calendar trade month for the relevant range of calendar years. Figure 6-4 shows the standard deviation of daily prices for each month for the July 2014 delivery month. The monthly standard deviation is confined to a relatively narrow band with no strong indications that any calendar month represents particularly high price variability. The spike in standard deviation for October 2012, which also appears in Figure 6-3, appears to be an anomaly. Similar charts for October 2014, January 2015, and April 2015 delivery appear as Figure 6-5, Figure 6-6, and Figure 6-7. While the October and April charts show very narrow ranges of relatively low standard deviations, the January chart shows a significant increase in standard deviation for 2014 trading months, relative to the prior years, attributable to the shock of the Polar Vortex.

Figure 6-4: Monthly Standard Deviations for July 2014 Delivery

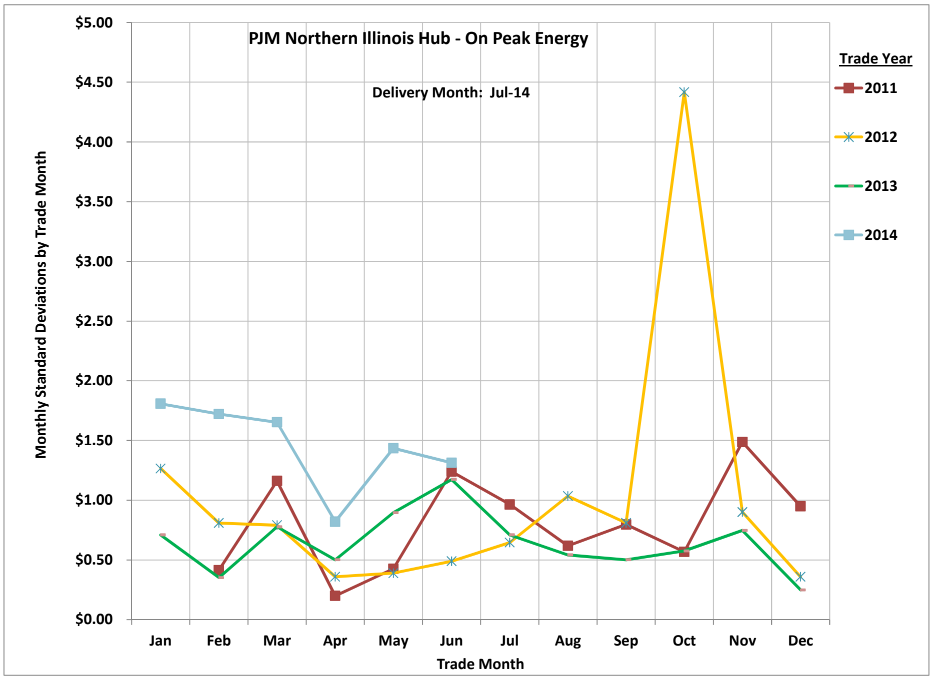


Figure 6-5: Monthly Standard Deviations for October 2014 Delivery

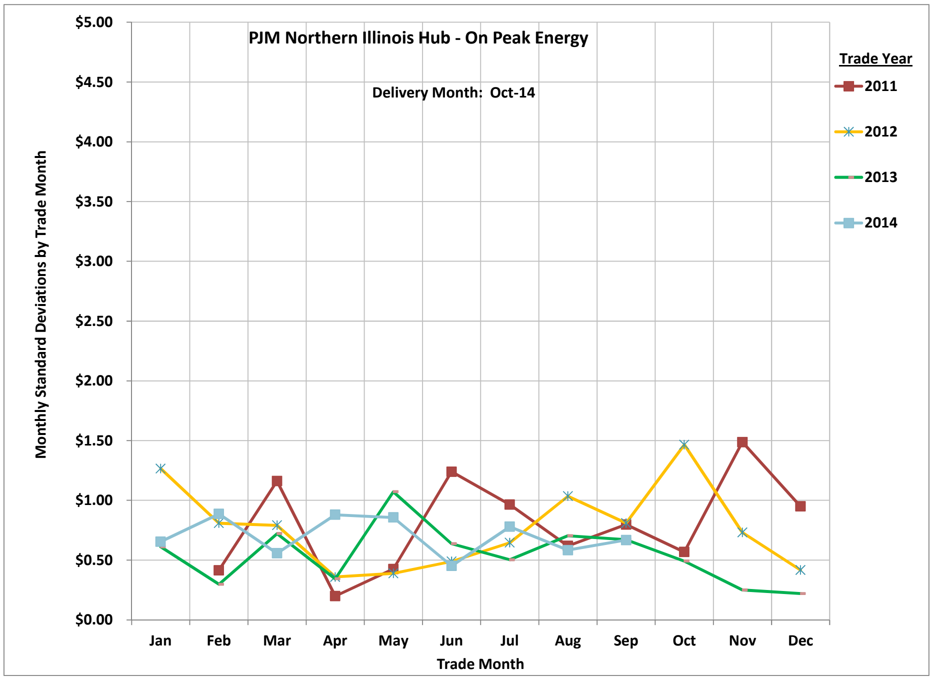


Figure 6-6: Monthly Standard Deviations for January 2015 Delivery

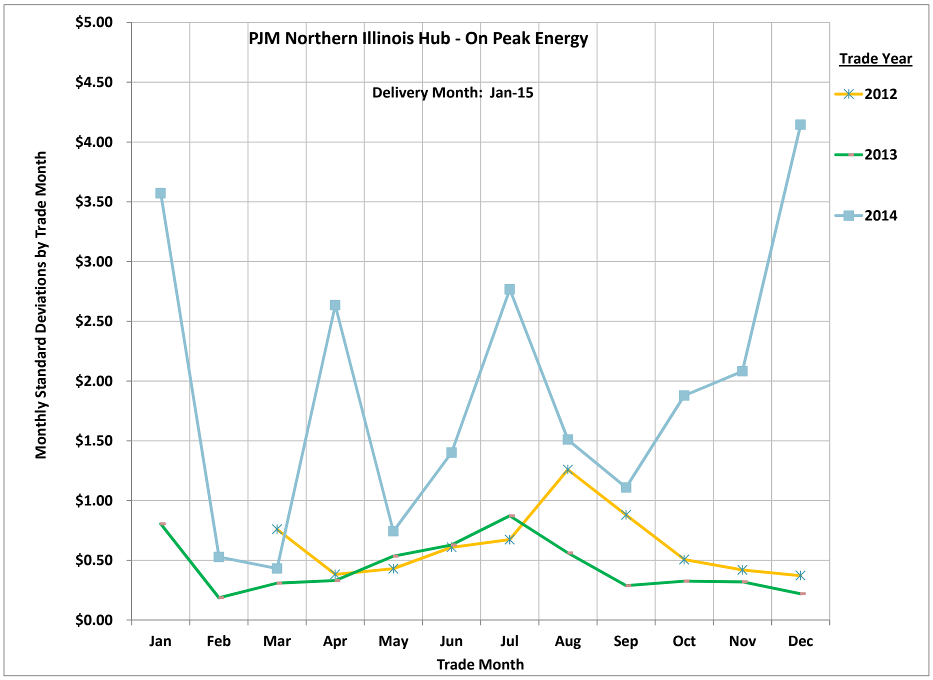
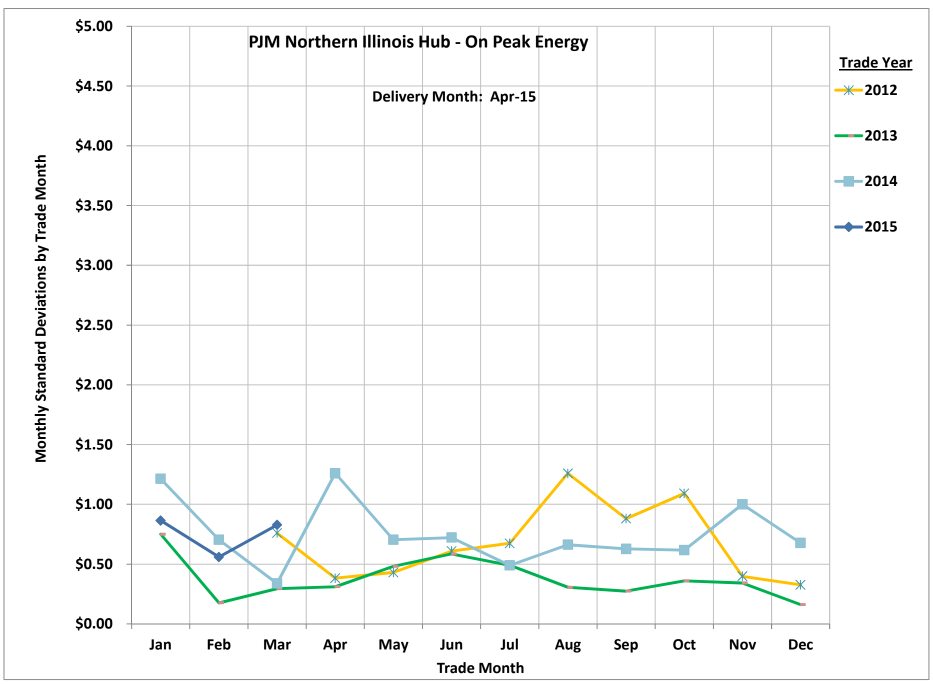


Figure 6-7. Monthly Standard Deviations for April 2015 Delivery



The preceding charts suggest 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 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.

6.5.2.2 Procurement Schedules and Portfolio Volatility

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 described above.

Four procurement schedules were considered. Each schedule avoids procurement events in the months of January, February, July and August. The first schedule represents a backcast of the 2015 procurement plan schedule (ignoring the extra six percent of load to be hedged in the summer months) with procurements in April and September from 2012 through 2014 and in April of 2015.

The second schedule considered also has two annual procurement events, occurring in March or April and in September or October. The cumulative procurement targets are adjusted somewhat so that, barring significant changes in load forecasts or failures to fill the targeted quantity in a given event, 25% of the requirement for each delivery month would be procured in each of four events over 18 months.

The third procurement schedule considered incorporates a third annual event in May or June, slips the fall event out to October or November, and allocates the targeted procurements for each delivery month evenly over five events and roughly 14 to 18 months.

The fourth procurement schedule considered adds a fourth event, sliding the October-November event back to September-October and inserting an event in November or December. Targets are set so that the portfolio for each delivery month is acquired in five equal parts over 13 months.

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 from each designated event date range (one to two months of trade days) and calculated a weighted average portfolio cost for each delivery month under each procurement schedule, based on the designated target levels. The distributions over all iterations of the portfolio average costs were analyzed to determine means and standard deviations. Mean average portfolio prices are plotted for each procurement schedule in Figure 6-8, while standard deviations are shown in Figure 6-9. The means are similar for all delivery months, and no plan has the lowest cost or the highest cost in all 12 delivery months. Contrary to original expectations, the standard deviations for six delivery months are lowest under the 2015 Procurement Plan schedule. Standard deviations are highest for six delivery months under the Four-Event schedule.

Figure 6-8: Portfolio Price Means

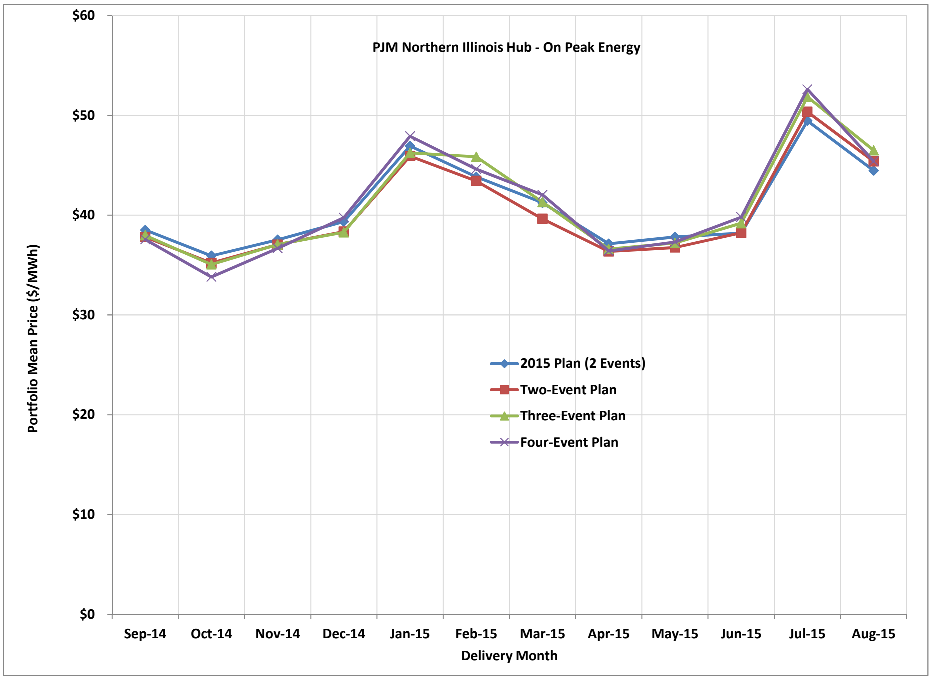
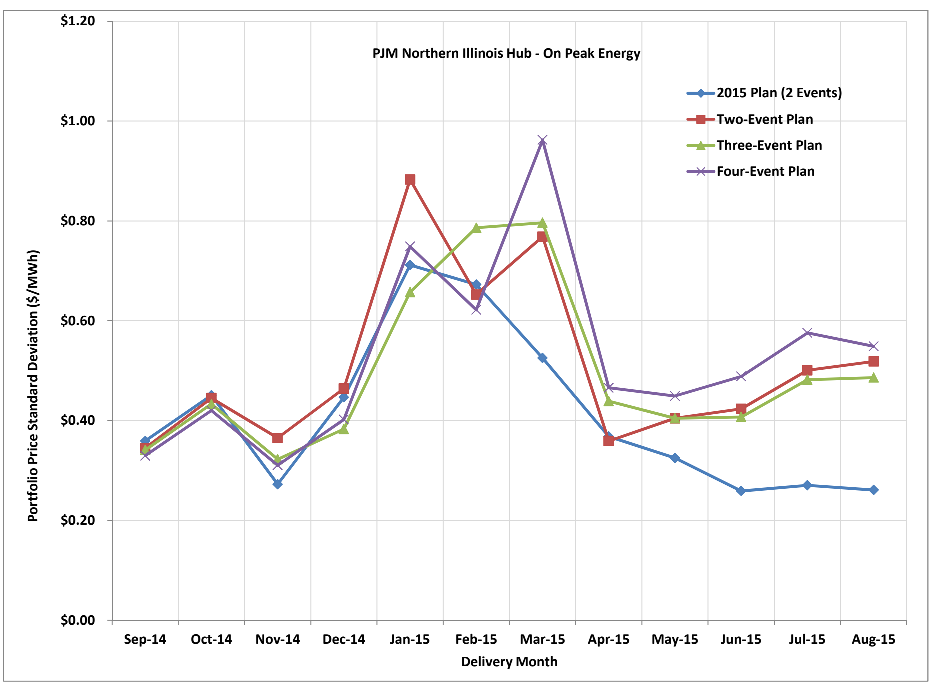


Figure 6-9. Portfolio Price Standard Deviations



6.5.2.3 Forward Price Curve Analysis

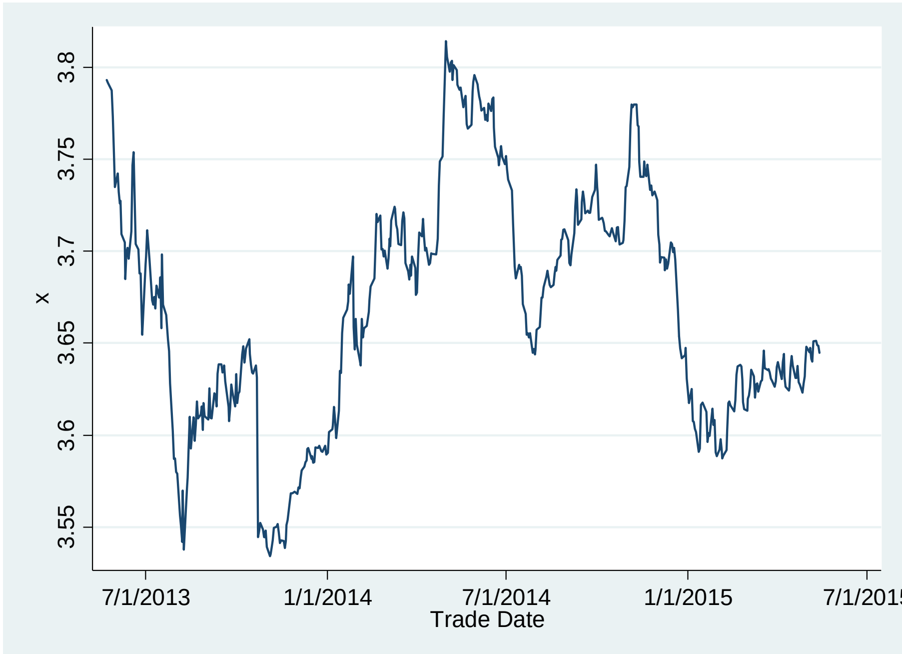
Only one possible evolution of forward prices is observed in historical data, which makes it difficult to draw strong conclusions or make hedging strategy recommendations based on a few years of data. The above analysis was conducted with an approach that had limited ability to analyze possible futures. In order not to have particular recent trends or events drive the conclusions, an analysis was also conducted that focused on a model-based decomposition of the sources of seasonal and stochastic fluctuations. This second approach, more grounded in financial economics was used to assess key aspects of electric energy forward prices that are important considerations for price hedging. The IPA analyzed MISO Illinois hub and PJM Northern Illinois hub futures prices with a general model for use with futures that have seasonally-varying prices.[149] This modeling approach has three basic steps for characterizing price volatility of a particular forward or futures product.

First, for each trading date, the de-seasonalized average of the logarithm of prices for the current forward curve of N months is calculated. Logarithms are used, as is standard in statistical price analysis because commodity prices have probabilistic distributions that resemble the log distribution more than the normal distribution, which simplifies statistical analysis. To insure that all seasonality is removed, a 24 month series (N=24) is used because it is a multiple of 12. Figure 6-10 and Figure 6-11 show the de-seasonalized log prices for PJM and MISO on-peak futures, respectively. Equal length subsets of the 3.5 years of data used for PJM futures and the 2 years of data available for MISO futures indicate that in the more recent sub-period, the volatility of de-seasonalized futures prices has declined slightly. The de-seasonalized log price series is modeled as a stochastic, or uncertain, variable that represents the trajectory of average prices over time.

Figure 6-10: PJM On-Peak De-seasonalized Average Log of Prices for 24 Maturities

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

Figure 6-11: MISO On-Peak De-seasonalized Average Log of Prices for 24 Maturities



Second, the seasonal premia by calendar month, expressed as percent of the de-seasonalized price, are calculated as the average difference between the daily prices for a product that expires (or physically delivers) in the specific calendar month and the daily de-seasonalized prices. By construction, the positive and negative premia sum to zero over the 12 calendar months. For simplicity, these seasonal premia are modeled as deterministic shaping factors, and are the same regardless of year. The shapes for PJM and MISO on-peak futures are shown in Figure 6-12 and Figure 6-13, respectively.

Figure 6-12: PJM On-Peak Seasonal Premia

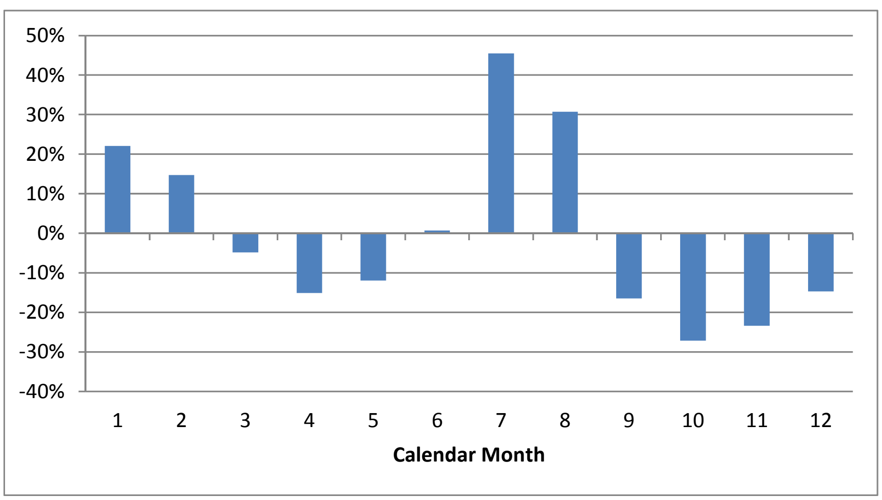
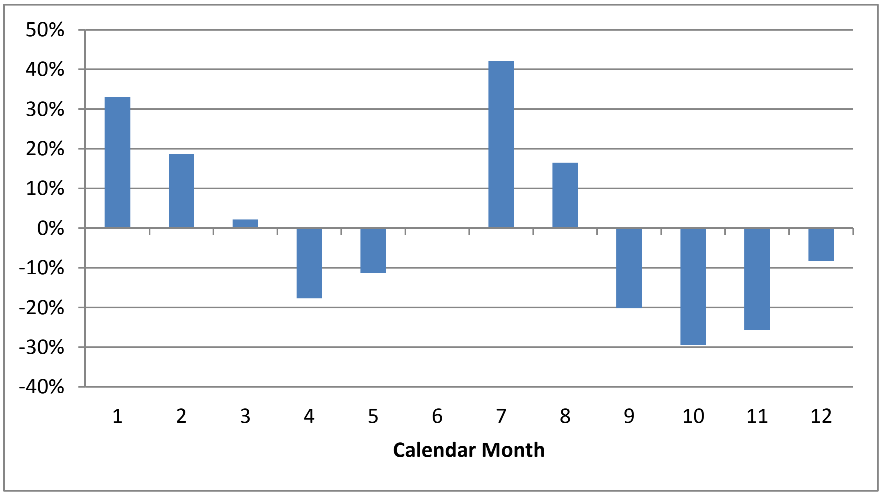


Figure 6-13: MISO On-Peak Seasonal Premia



The third and final factor in the decomposition of forward prices is what is known as the "convenience yield." The convenience yield is the residual of the forward price minus the deseasonalized forward price and the seasonal premium. The convenience yield is modeled as a second stochastic factor, which varies by time to maturity, accounting for the dynamics of supply-demand imbalances. The average convenience yield in this model is zero. The volatility term structures of convenience yields for PJM and MISO on-peak futures are shown in Figure 6-14 and Figure 6-15, respectively.

Figure 6-14: PJM On-Peak Convenience Yield Volatility

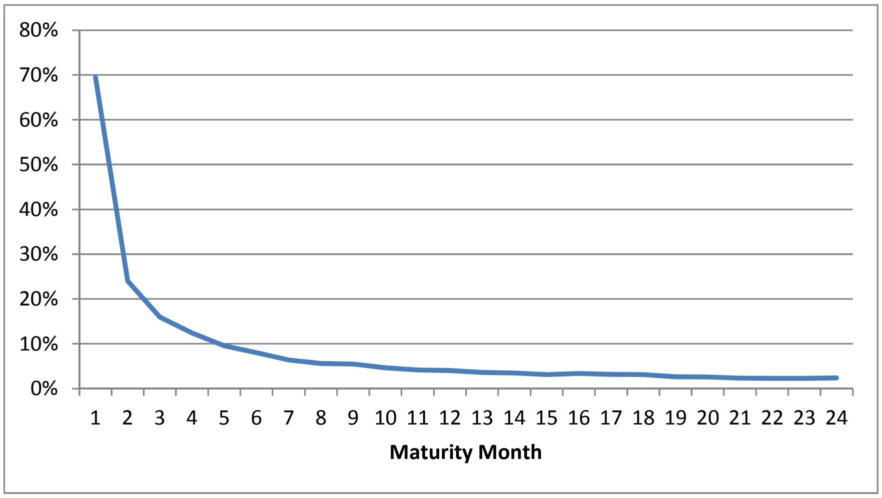
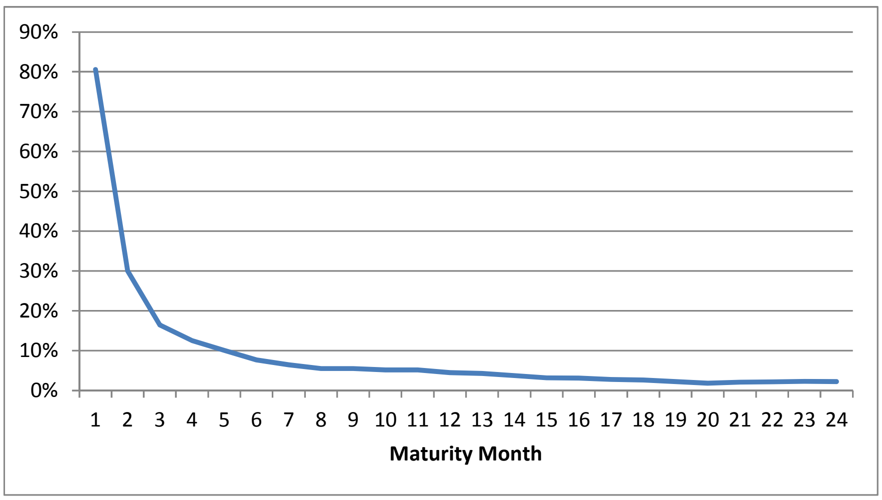


Figure 6-15: MISO On-Peak Convenience Yield Volatility



While the IPA did not include modeling of seasonal futures prices in the 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 significantly change the energy procurement schedule and approach for its 2016 Plan from the approach established in the 2015 Procurement Plan. Additional statistical and modeling analysis would be needed to justify additional revisions to the procurement schedule. The IPA will continue to review and suggest improvements (if necessary) to its risk management approach and procurement process in future procurement plans.

6.6 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 expected 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 light of the DC Court of Appeals vacation of Order 745, PJM proposed changes pending the resolution of Order 745 issues that would significantly alter the manner in which demand resources could participate in RPM. Under that proposal, the demand curve used in the RPM would be altered to reflect offers made by wholesale entities to reduce load. However, in March 2015, FERC issued an order that rejected PJM's filing as premature.

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.

The PJM and MISO capacity markets are FERC jurisdictional, governed by tariffs filed with and approved by FERC. The DC Court of Appeals viewed demand response compensation as involving direct regulation of retail markets and thus a matter exclusively within state jurisdiction. This decision, which is currently before the U.S. Supreme Court, could lead to a more comprehensive challenge to ISO-supplied demand response compensation. In the future, it may not be possible to simply rely on ISO capacity payments to compensate demand response providers. The role of states and state agencies in compensating demand response may become much more important. As this issue is resolved in the courts, the IPA will revisit it in future procurement plans as necessary.

Chapter 7 of this plan provides details and additional discussion regarding demand response resources.

7 Resource Choices for the 2015 Procurement Plan

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) incremental energy efficiency; (2) energy procurement strategy; (3) balancing recommendations; and (4) demand response. Procurement of additional Renewable Resources, including wind, solar and distributed generation is considered separately in Chapter 8.

7.1 Incremental Energy Efficiency

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.[150]

The IPA bases its assessment 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.[151] 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,"[152] 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,"[153] 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."[154]

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.[155] 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."[156] 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"[157] 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.[158]

This section includes discussion related to programs and measures which the IPA recommends for inclusion in the 2016 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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[150] 220 ILCS 5/16-111.5B(a)(2).
[151] 220 ILCS 5/16-111.5B(a)(3).
[152] 220 ILCS 5/16-111.5B(a)(3)(C).
[153] 220 ILCS 5/16-111.5B(a)(3)(D).
[154] 220 ILCS 5/16-111.5B(a)(3)(E).
[155] See 220 ILCS 5/8-103(d).
[156] 220 ILCS 5/16-111.5B(a)(3).
[157] 220 ILCS 5/16-111.5B(a)(4).
[158] 220 ILCS 5/16-111.5B(a)(5).

7.1.1 Incremental Energy Efficiency in Previous Plans

The IPA's 2016 Procurement Plan is the fourth plan to include energy efficiency programs under Section 16-111.5B. Table 7-1 summarizes the total MWH of approved programs from each previous Procurement Plan.

Table 7-1: 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	**239,813**	**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*
Proposed in 2016 Plan	**70,123**	**87,453**

The total expected reductions listed above are the gross totals for the programs available to all potentially eligible retail customers.[159] 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.

As demonstrated through the table above, prior years' Plans have also featured contract offerings for more than a single delivery year. For instance, for programs included in the 2014 Plan, ComEd allowed for contracts for the upcoming three delivery years (2014-15, 2015-16, 2016-17), resulting in the "projected savings" values for future years shown in Table 7-1. Further discussion on the treatment of multi-year contracts for this year's Plan can be found in Section 7.1.4. below.

The IPA's 2015 Procurement Plan included the approval of eight expanded or new programs for Ameren Illinois and ten for ComEd.[160] One significant aspect of the 2015 Plan's 16-111.5B program portfolio was the inclusion of residential lighting and behavioral programs. In a separate docket, the ICC ordered these programs moved from the Section 8-103 Energy Efficiency portfolio of programs to the Section 16-111.5B process, thus allowing for a different portfolio of programs under Section 8-103 and causing an expansion of

[159] 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))

[160] The 2014 Procurement Plan included five expanded or new programs for Ameren Illinois, and eight for ComEd; the 2013 Procurement Plan included eight expanded or new programs for Ameren Illinois and seven expanded or new programs for ComEd.

the budget and savings associated with the Section 16-111.5B programs.[161] Similarly, for the 2014 Plan, ComEd significantly increased the size of its Section 8-103 Small Business Direct Install program via the Section 16-111.5B process, thus growing its overall Section 16-111.5B portfolio.

The 2014 and 2015 Procurement Plans also discussed additional policy issues arising under Section 16-111.5B. For instance, the 2014 Plan included discussion of feedback mechanisms, transition year program expansion, DCEO participation, and consideration of all third party bids.[162] In approving that Plan, the Commission's most significant decisions were determining that DCEO is not a utility for the purposes of the Section 16-111.5B filings, and the approval of a methodology for the consideration of potentially duplicative and competing third-party energy efficiency programs.[163]

In its draft and filed 2015 Plan, the IPA proposed procuring a new super-peak energy efficiency block product as a supply resource (i.e., as a "standard wholesale product" procured pursuant to its authority under Section 16-111.5(b)(3)(iv) of the PUA). While the Commission declined to approve this proposal as a stand-alone procurement strategy, it did approve the IPA's alternative approach of allowing for modification of the solicitation of third-party programs under Section 16-111.5B to take into account the value of avoiding peak energy consumption.[164] The 2015 Plan also requested the approval of consensus language taken from 2014 workshops and raised issues related to stakeholder participation in "duplicative" bid determinations for Commission consideration.

7.1.2 2015 Workshops

In its Order approving the 2015 Plan, the Commission observed that "[a] significant problem with procurement proceedings is the expedited schedule combined with a relatively large number of contested issues and parties," making it "difficult for the Commission to deal with complex economic issues" such as the Section 16-111.5B issues raised by some parties.[165] As a result, the Commission ordered that many contested issues be further addressed through workshops to be held in 2015. A discussion of the status of those issues, and the resulting workshops, can be found below.

7.1.2.1 Energy Efficiency as a Supply Resource Workshops

As referenced above, the IPA included a primary and alternative proposal in its filed 2015 Plan for the procurement of energy efficiency as a supply resource. In its Final Order approving the 2015 Procurement Plan, the Commission concluded the following:

> The Commission concurs with those parties that suggest energy efficiency is a valuable tool and should be pursued as a matter of policy and appreciates the efforts of the IPA to pursue innovative ideas. The Commission believes such efforts should be pursued pursuant to Section 16-111.5B of the PUA and hereby adopts the IPA's alternative proposal to inform the development and evaluation of the RFPs for programs submitted for consideration in the IPA's 2016 Procurement Plan.
>
> The Commission directs the parties to commence workshops, coordinated by Staff, to pursue the IPA's alternative proposal, with such workshops beginning in January and concluding by mid-February to allow the workshops to inform development of the RFPs. Among other things, those workshops should consider whether an additional RFP for energy efficiency programs will be necessary, the duration of any such programs, whether the IL-TRM should govern these types of programs, and how such programs should be evaluated. To the extent

[161] See Dockets Nos. 13-0498 (Ameren Illinois) and 13-0495 (ComEd).
[162] See 2014 IPA Procurement Plan at 81-86.
[163] Docket No. 13-0546, Final Order dated December 18, 2013 at 149.
[164] Docket No. 14-0588, Final Order dated December 17, 2014 at 157.
[165] Docket No. 14-0588, Final Order dated December 17, 2014 at 224.

> practical, the Commission directs ComEd and Ameren to propose energy efficiency programs consistent with the IPA's goals when each provides its energy efficiency proposals pursuant to Section 16-111.5B of the PUA next year.[166]

ICC Staff coordinated workshops to pursue IPA's alternative proposal. While consensus was not reached among stakeholders on all issues related to the IPA's alternative proposal,[167] the workshops did result in changes made to Ameren's and ComEd's RFPs issued pursuant to Section 16-111.5B(a)(3) and allowed for the review of bid submissions using hourly energy values. Those changes also reflected consideration of interested stakeholders' comments.

One contested issue on which consensus was not reached was the appropriate contract length for Section 16-111.5B programs evaluated using hourly load profiles under the IPA's alternative proposal. During workshops some parties argued that the nature of programs available, and vendors willing to participate, would be limited by shorter contracts, especially the one-year contracts being offered through the utilities' RFPs seeking programs for the 2016 Plan. While the IPA tentatively understands that ComEd and Ameren Illinois will likely be offering contracts up to 3 years in length for Section 16-111.5B programs solicited for inclusion in the 2017 Plan (including peak-hour oriented energy efficiency programs), the Agency would appreciate stakeholder perspective on the appropriate contract length for programs falling under its Section 16-111.5B alternative proposal as part of comments made on this draft Plan.

7.1.2.2 Stakeholder Advisory Group TRC Subcommittee Workshops

Section 16-111.5B requires the IPA to include incremental "energy efficiency programs and measures it determines are cost-effective."[168] Under Section 16-111.5B, "the term 'cost-effective' shall have the meaning set forth in subsection (a) of Section 8-103 of this Act,"[169] meaning "that the measures satisfy the total resource cost test."[170] Section 1-10 of the IPA Act defines the "total resource cost test" as follows:

> "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 for 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.

Since its introduction into the law in 2007, this definition has left many stakeholders grappling with questions around what costs and benefits are appropriate to include in cost-effectiveness determinations and how to appropriately quantify any such costs and benefits. In general, advocates for increased energy

[166] Ibid.
[167] Among the issues on which full consensus was not reached include the definition of "super-peak," the appropriate program/contract length, and the treatment/definition of demand response.
[168] 220 ILCS 5/16-111.5B(a)(4).
[169] 220 ILCS 5/16-111.5B(b).
[170] 220 ILCS 5/8-103(a).

efficiency seek a more robust accounting of benefits and less for costs (increasing the number/scale of programs which have a TRC above 1.0), while those in favor of less spending on energy efficiency seek the inclusion of more or higher costs and less for benefits (having the opposite effect).

In the docketed proceeding for the approval of the 2015 Plan, the Natural Resources Defense Council ("NRDC") raised a number of issues related to how TRC tests are conducted, what costs were being included by the utilities, and whether all allowable benefits were properly being taken into account.[171] In approving the IPA's 2015 Procurement Plan, the Commission directed SAG-coordinated[172] workshops to consider multiple unresolved issues related to the calculation of the TRC:

> The Commission refers the three issues raised by NRDC to be addressed at workshops conducted by the SAG. In the event the SAG is unable to conduct the workshops, for whatever reason, the Commission directs the Staff to conduct the workshops. Among the broader issues to be explored in the workshops, the Commission specifically directs the parties to address why Ameren does not utilize its best estimate of marginal line losses in place of average line losses, which ComEd already utilizes. Additionally, the parties should address the possibly outdated literature relied upon by ComEd in its opposition to the inclusion of DRIPE in the TRC test. The Commission also finds the AG's arguments regarding the inclusion of DRIPE intriguing. As noted above, procurement proceedings are not the ideal forum for considering complex economic issues and the Commission urges the parties to make serious efforts to reach consensus on at least some of these issues. While the Commission does not wish to open a proceeding for the purpose of addressing possible changes to the TRC test at this time, it may be necessary if the parties are unable to make progress in the workshop forum.[173]
>
> NRDC also argues that Ameren is overstating its overhead or administrative costs as used in the TRC test and notes that ComEd does not use a similar percentage adder when performing the TRC test. Ameren disagrees, while Staff suggests Ameren should not be using any generic adder for all programs as administrative costs are likely to vary by program size type and size. The Commission finds the quality of evidence relating to this issue lacking. No party presented evidence regarding Ameren specific overhead or administrative costs though it is almost certain they exist. To the extent the utilities do not explicitly track this information already, the Commission hereby directs Ameren and ComEd to 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. The Commission rejects Staff's suggestions that Ameren should use a value of zero for a cost that almost certainly exists and could probably be estimated with reasonable certainty. As a result, while the Commission must reject NRDC's recommendations on this issue because they are not supported by the record, the Commission directs the parties to address this issue in the workshops discussed above.[174]
>
> According to Staff, the IPA indicates it appreciates that Section 16-111.5B(a)(4) in isolation could be understood to demand a more rigorous evaluation, even justifying the use of evaluative criteria separate from criteria used to evaluate programs under Section 8-103. Staff says the IPA suggests in the procurement plan that a workshop could also consider if the IPA should develop and perform an independent TRC calculation with distinct inputs and

[171] Further discussion of the specific issues raised in last year's Plan litigation can be found in Docket No. 14-0588 and in the Commission's Final Order in that Docket, dated December 17, 2014 at 164-179.
[172] The "SAG" is the Stakeholder Advisory Group formed in 2008 to oversee the implementation of energy efficiency programs in Illinois. For more information, see www.ilsag.info.
[173] Docket No. 15-0588, Final Order dated December 17, 2014 at 224.
[174] Id. at 225-226.

> assumptions rather than relying on inputs provided by the utilities. (Staff BOE Attachment A at 222) The Commission agrees that this would be a reasonable topic to address in the workshops discussed above. [175]

To this end, the SAG established a Total Resource Cost ("TRC") Test Subcommittee and led a series of workshops over the period of January-August 2015, with plans to continue into September (and potentially beyond). The workshops were held as a series of meetings, conference calls, and written requests for responses to questions. While participants were not able to reach agreement on all issues, some consensus items did emerge from the workshops.[176]

The IPA appreciates the efforts of the SAG facilitators and Subcommittee members to address these issues. While there was a pronounced lack of agreement on key issues, all participants engaged fully on the issues and provided substantial and detailed information and arguments. A brief discussion of each of those issues is included below.

7.1.2.2.1 Use of Marginal Line Losses

The line losses avoided by energy efficiency measures are among the "avoided electric utility costs" included in a TRC calculation. Line losses may be calculated in two ways: average line losses, which are a measured and published figure; or marginal line losses, which are generally determined by using actual system information and more detailed calculations. In Docket No. 14-0588, NRDC argued that because line losses grow exponentially with load and are most pronounced during peak hours, marginal line loss calculations are better able to account for line losses as a square of the load.

ComEd has historically used marginal line losses in their TRC tests; this was ComEd's approach for programs submitted for the 2015 Plan, and the same held true for the 2016 Plan. Alternatively, Ameren Illinois has historically incorporated average line losses in its TRC calculations. Through the TRC sub-committee workshop process, parties agreed that for 2016 Plan program submissions, Ameren Illinois would use ComEd's marginal line loss information in the absence of marginal line loss information specific to Ameren Illinois. The TRC calculations provided by Ameren Illinois for the 2016 Plan thus reflect marginal line losses.

7.1.2.2.2 Demand Reduction Induced Price Effects ("DRIPE")

Market energy prices are driven in large part by load levels, and reducing electric loads should lead to a reduction in market prices. Energy efficiency programs and measures reduce consumption and, as a consequence, reduce electric loads. In turn, these load reductions should lead to price reductions in generation rates paid by electricity consumers (independent of direct savings from installation of the energy efficiency measures themselves), with reduced demand now operating in an environment of unchanged supply.

That reducing consumption reduces market prices is not a novel concept (although questions persist about the magnitude and persistence of such price effects), nor is the concept that consumers achieve economic benefit from reduced prices. In Docket No. 14-0588, NRDC argued that those price effects from reduced demand created by energy efficiency programs—known as demand reduction induced price effects, or "DRIPE"—should be included as a benefit in utility TRC calculations. Citing the complexity of resolving such issues in a 90 day docket, the Commission directed that the issue be addressed through workshops.

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[175] Id. at 226.
[176] Draft TRC Subcommittee Report dated 6/11/2015, available at http://www.ilsag.info/subcommittees.html

The TRC subcommittee reviewed two reports on DRIPE: one was from Resource Insight Inc.;[177] another was from Exeter Associates, Inc.[178] The subcommittee also heard commentary from, and asked questions of, technical experts offered by each side of the DRIPE debate.

Despite all parties' best efforts, no consensus on the impact of DRIPE was reached. Open questions include whether or how such price effects fit into the definition of "benefits" found in the statutory TRC test definition (and whether DRIPE benefits are, or need be, reliably "quantifiable"), the persistence of price effects from demand reduction, and whether empirically observed price effects show causality versus mere correlation.

The TRC subcommittee also reviewed information on other states' practices. Of the twelve other restructured states, seven (Connecticut, Rhode Island, Massachusetts, Maryland, the District of Columbia, Delaware, and Maine) include DRIPE in their cost-effectiveness screening of efficiency measures.[179] Though not a restructured state, Vermont regulators also include the impacts of DRIPE in neighboring restructured states in their screening of the benefits of efficiency measures installed in their state.

Neither utility included DRIPE benefits in its assessment of energy efficiency programs and measures offered for the 2016 Plan.

7.1.2.2.3 Use of Non-Energy Benefits in TRC Tests

The statutory definition of the TRC test describes acceptable benefits as "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." Some parties argue that some less obvious benefits of energy efficiency programs may be accounted for in the TRC even if not directly related to the supply of energy (and are indeed envisioned by law to be incorporated through language directing the inclusion of "other quantifiable societal benefits").

Such benefits are known as non-energy benefits, or "NEBs." NEBs may incorporate several different categories of benefits from energy efficiency programs:

- Environmental adders – specifically, reductions in SOx,, NOx, and, other air pollutants and emissions[180]
- Water – Resource benefit
- Societal Impacts – health, safety, comfort, building durability, etc.
- O&M cost avoidance
- Economic – Job creation
- Participant Perspective – water and sewer savings, fewer shutoffs, fewer calls to the utility, fewer reconnects, property value benefits, fewer fires, reduced moving costs, fewer illnesses and lost days from work or school, net benefits for comfort and noise, and net benefits for additional hardship.

Positioned for consideration by the TRC subcommittee was which non-energy benefits (NEBs) should be included in the Illinois TRC calculation, how they should be quantified, and whether they should—or could—be quantified by program/measure type.[181] A review of other state practices showed that some state electric

[177] "Analysis of Electric Energy DRIPE in Illinois", Resource Insight, Inc., Sept 3, 2014.
[178] "Assessment of the Costs Avoided through Energy Efficiency and Conservation Measures in Maryland," Exeter Associates, Inc., April 2014.
[179] http://ilsagfiles.org/SAG_files/Subcommittees/IPA-TRC_Subcommittee/6-16-2015_Meeting/DRIPE_Comparison_Exhibit_2015_Final_Draft.pdf
[180] Carbon dioxide savings are addressed separately and more explicitly under Illinois law, as the TRC definition requires that "reasonable estimates shall be included of financial costs likely to be imposed by future regulations and legislation on emissions of greenhouse gases." (20 ILCS 3855/1-10)
[181] By way of example, NRDC has proposed using a 15% default non-low income benefits adder and a 30% default low income benefits adder—demonstrating a marked increase in non-energy benefits associated with programs targeted toward low-income households.

efficiency programs use varying costs for NEBs ranging from 10 to 30 percent;[182] others also include a price for carbon in addition to the NEBs percentage.[183]

No consensus was reached on the appropriate treatment of non-energy benefits for the 2016 Plan, although agreement appears to have been reached that non-energy benefits will be considered for inclusion in the next edition of the Technical Reference Manual ("TRM") on a measure-specific basis.

7.1.2.2.4 Application of Administrative Costs in TRC Tests

Turning to the cost side of the TRC ledger, an additional topic left to the TRC subcommittee concerned administrative costs associated with Section 16-111.5B incremental energy efficiency program administration. In Docket No. 14-0588, NRDC contested Ameren Illinois' application of a blanket 15% administrative cost adder applied to all Section 16-111.5B programs, believing that such costs were inflated and bore little connection to the actual costs of administering the programs being evaluated. The Commission resolved the issue with the following statement:

> NRDC also argues that Ameren is overstating its overhead or administrative costs as used in the TRC test and notes that ComEd does not use a similar percentage adder when performing the TRC test. Ameren disagrees, while Staff suggests Ameren should not be using any generic adder for all programs as administrative costs are likely to vary by program size type and size. The Commission finds the quality of evidence relating to this issue lacking. No party presented evidence regarding Ameren specific overhead or administrative costs though it is almost certain they exist. To the extent the utilities do not explicitly track this information already, the Commission hereby directs Ameren and ComEd to 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.[184]

While the utilities are beginning to take steps toward tracking administrative costs by program, program-specific administrative cost information for programs submitted for inclusion in the 2016 Plan has not yet been developed. As a result, some estimation of administrative costs must once again be applied.

In addressing this issue, one proposed solution raised by TRC Sub-committee identified the following categories of administrative costs:

> **Category 1: EM&V –** will add to each IPA program (3%). Utility will take 3% from each program selected, lump together.
>
> **Category 2: Program Management** – (3-4%) Utility will take program-specific and will be allocated to programs in screening. Other management admin costs, invoicing, etc. will be allocated based on program budget.
>
> **Category 3: Increase in other Admin: Marketing, General Admin, other non-assignable** – (Approximately 4%) Assignable will be allocated to IPA programs based on program budgets. Non-assignable (RFP, regulatory approval, legal, potential studies, etc.) will be allocated across the portfolio. Utilities will track these costs. There was non-consensus on whether to include these costs when screening IPA programs.

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[182] See the SAG website at http://www.ilsag.info/subcommittee_ipa-trc.html for more information on how other states calculate NEBs.
[183] Again, as noted above, Illinois law requires that TRC tests include "reasonable estimates . . .of financial costs likely to be imposed by future regulations and legislation on emissions of greenhouse gases." (20 ILCS 3855/1-10)
[184] Docket No. 14-0588, Final Order dated December 17, 2014 at 224.

The TRC Sub-Committee discussed the idea that the utilities could screen both with 7% and 11% blanket administrative cost rates and report those numbers to the IPA for program review.[185] The programs actually submitted to the IPA for review featured utility administrative cost screenings using different, and slightly higher, values. The administrative costs used by Ameren and ComEd in TRC screenings can be found in Sections 7.2.3.7 and 7.2.4.4, respectively.

7.1.2.2.5 Independent TRC Tests by IPA

Section 16-111.5B of the PUA requires that the IPA include in its procurement plan "energy efficiency programs and measures it determines are cost-effective" (emphasis added).[186] However, Section 16-111.5B energy efficiency programs and measures are initially identified and reviewed by the utilities and submitted to the IPA through an assessment process including initial determinations made as to cost-effectiveness. Perhaps more importantly, Section 16-111.5B(b) requires that "the term 'cost-effective' shall have the meaning set forth in subsection (a) of Section 8-103 of this Act," leaving questions as to the degree to which the IPA could adopt an approach to cost-effectiveness screening distinct from that already applied by the utilities under Section 8-103.

The issue of whether the IPA can (and should) perform an independent TRC calculation, with distinct inputs and assumptions (rather than relying on inputs provided by the utilities), was put to the TRC subcommittee for further discussion and review. By consensus, the subcommittee determined that IPA does not need to perform independent cost-effectiveness screening with truly independent inputs, assumptions, and methodology, but must independently review assumptions.

As such a review requires necessary information from the utilities, the TRC subcommittee also determined that the utilities are to provide a summary of the content of their cost-effectiveness screening model and the basis for any cost and benefit assumptions.

7.1.3 Prior Year Consensus Items

The 2014 Plan included a number of consensus items from ICC staff-led workshops and the IPA requested (and received) Commission approval of those items.[187] The consensus items included:

- Both new and expanded programs may be approved for up to three-year increments.
- DCEO may bid programs into the utility-run RFPs and should pass the TRC test as indicated in the legislation.
- Any utility savings goals pursuant to Section 8-103 and contractor performance "goals" pursuant to Section 16-111.5B are separate and non-transferrable. Budgets should also be kept separate.
- Utilities should provide the IPA with all bids to the RFP (on a confidential basis) so the IPA may independently evaluate the bids.
- The IPA also believes that parties should work collaboratively on contract principles for successful bidders, which may include pay-for-performance language and grant the utility "flexibility" to reward successful programs while minimizing resources spent on unsuccessful programs.

The 2015 Plan included a number of consensus items from the staff led workshops and the IPA requested (and received) Commission approval of those items.[188] The consensus items included:

- Deeming and Evaluation for Future Section 16-111.5B Energy Efficiency ("EE") Programs

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[185] http://ilsagfiles.org/SAG_files/Subcommittees/IPA-TRC_Subcommittee/6-16-2015_Meeting/SAG_TRC_Subcommittee_Attendees-and-Meeting-Notes_6-16-2015_Final_Draft.pdf
[186] 220 ILCS 5/16-111.5(a)(4).
[187] See Appendix B-2 for the ICC Staff report on the workshops.
[188] Ibid.

- Deeming and Evaluation for Previously Approved Section 16-111.5B EE Programs, Program Year ("PY") 6 and PY7
- Responsible entity
- Policy or Clarity on Status of Bid Accepted into IPA Procurement Plan and Approved by the Commission and Flexibility
- Continuity for Multi-Year EE Programs
- Evaluation Budget and Process Evaluations

The Agency requests that the Commission reaffirm its past approval of the consensus items from prior years' workshops. Further, the Agency requests that the Commission approve such items prospectively, expressly allowing for their application to the 2016 RFP solicitation and bid evaluation process.

7.1.4 Policy Issues for Consideration in the 2017 Plan

In this draft 2016 Plan, the IPA seeks feedback from stakeholders on two items that could result in the Commission giving the IPA and utilities useful direction for the development of the 2017 Plan.

The first issue is the process by which the utilities screen bids received in the RFP process. In its submittal, Ameren Illinois applied the screening for duplicative programs prior to the running of the TRC analysis, while ComEd did the opposite. While the IPA appreciates the time and effort required to conduct a TRC analysis, the IPA believes it is preferable to conduct the TRC screening on every bid that complies with the basic requirements of the RFP, and then conduct any other screening (e.g., for duplicative programs) thereafter. While it could be argued that the RFPs require the bidder to assess if their proposal is duplicative of existing programs, that assessment is sufficiently subjective that it should be treated differently from other RFP requirements. Having a complete record of TRC analyses submitted by the utilities will aid the IPA in its review of programs for consideration for inclusion in the Plan.

The second issue concerns how Section 16-111.5B programs may be used to "expand" a portfolio of Section 8-103 programs that have not yet been approved by the Commission. For the 2017 Procurement Plan to be developed during the summer of 2016 (incorporating information from utility assessments submitted to the IPA on July 15, 2016), this issue will be front and center: the utilities will be filing their next set of three-year plans in the Fall of 2016 and therefore there will not be a set of existing (and approved) Section 8-103 programs against which the incremental programs would be considered. Consequently, the 2016 Plan and associated comment period (which informs any programs submitted for 2017) is the ideal opportunity for this discussion.

In the ICC Staff-led workshop conducted in 2013 as part of the process leading up to the development of the 2014 Plan, the issue of multiyear programs was extensively discussed, including how it would relate to the three-year planning cycle of the Section 8-103 energy efficiency programs. No clear resolution was reached and the 2014 Plan stated that "[i]n anticipation of the this triennial issue, a legislative change to either Section 16-111.5B or 8-103 would likely be necessary to create a mechanism for utilities to seek expansion of Section 8-103 programs through the Section 16-111.5B process, rather than seeking approval for new programs only when an 8-103 three year plan is awaiting Commission approval."[189] No such legislative change has been enacted at this time.

The IPA believes that an approach that will guarantee the inclusion of third-party bids for multi-year programs (three-years, or perhaps even longer) would be desirable. If strong third-party bids are received next year, they could have an opportunity to be included with fewer (or no) constraints related to the screening out of duplicative programs. By allowing the competitive market to suggest cost-effective programs

[189] 2014 Procurement Plan at 84.

through the RFP process, the opportunities to grow the energy efficiency sector in Illinois will be expanded, leading to additional job creation and benefits for customers.

7.1.5 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 nine appendices which may be found on the IPA website posting of the 2016 Procurement Plan at www.illinois.gov/ipa. Three of the Appendices (6, 8, and 9) in Ameren Illinois' submittal contain confidential data and are not included in the Appendices of this Plan.

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

7.1.5.1 Ameren Illinois Bid Review Process

Ameren Illinois received 32 bids—10 for the residential sector, and 22 for the business sector. One residential bidder withdrew their bid, and three bidders (one residential, two business) did not provide information to resolve incomplete aspects of their bids and thus were removed from consideration.

Of the 28 remaining bids, Ameren Illinois and a stakeholder review committee[190] determined that two residential bids and nine business bids were duplicative of existing Ameren Illinois programs. Four of the duplicative bids were considered duplicative of existing DCEO programs and were included in the bid evaluation as discussed below. One of the business bids was withdrawn during the subsequent review process, leaving 19 bids for consideration. Additionally, one of the bids that was initially identified as duplicative of DCEO programs was subsequently determined to be not duplicative.

In conjunction with the bid analysis conducted by Ameren Illinois and stakeholders, Ameren Illinois' consultant AEG also performed analysis on the bids. All documents submitted by the bidders were reviewed including the program proposal, measure information spreadsheet, and any supporting documentation. According to Ameren Illinois, the consultant's work operated as follows: AEG reviewed the detailed savings calculations provided by the bidders then independently calculated savings for each individual measure where a Technical Reference Manual ("TRM")[191] 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. 4.0, AEG adjusted the savings so they were in compliance. If there were major discrepancies, AEG went back to the bidder to gather more information on assumptions to determine why there were differences from the bidder savings and TRM calculations. In all but two cases, the issues were resolved and AEG was able to verify TRM compliant savings.[192] In the instances where AEG calculations differed from the bidder calculations, the AEG independently calculated savings values were utilized.

Eight bids did not pass the TRC and 11 bids passed the TRC. Of the 11 that passed, two were determined to be duplicative of DCEO programs and were not included by Ameren Illinois in its list of programs for inclusion in the Plan. Further discussion of the programs that were duplicative of DCEO programs is included below.

[190] The Committee included Environmental Law and Policy Center, NRDC, and DCEO. ICC Staff also participated in the review process. The IPA notes that Ameren Illinois appears to have more extensively engaged stakeholders in this year's review process than in past years.
[191] 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.
[192] One bidder did not agree with the IL-TRM In-Service Rate (ISR) and another bidder did not agree with the IL-TRM hours of use assumed in the analysis though further discussions did not resolve the disagreement as Ameren Illinois noted in the RFP that all applicable IL-TRM values would be used in the analysis.

7.1.5.2 Review of Ameren Illinois TRC Analysis

The IPA reviewed the TRC analysis provided by Ameren Illinois (using the BENCOST tool) and, subject to exceptions described in the sections below, generally concurred with the inputs, assumptions, and methodology.

Ameren Illinois does not have a marginal line loss study applicable to its service territory, so for the analyses for this submission, Ameren Illinois mirrored ComEd's marginal loss analysis study which showed an annual marginal distribution loss that is 1.65 times the average distribution loss. Ameren Illinois applied this ratio times their average distribution losses to arrive at estimated marginal line losses. Going forward, Ameren Illinois has demonstrated interest in completing a marginal line loss study in the future to make sure the costs are accurate. This approach is now consistent with the methodology used by ComEd and the approach advocated for by NRDC during consideration of the 2015 Plan.

Ameren Illinois employed a blanket administrative cost adder of 13.58% to all programs, and provided only rudimentary information on how that 13.58% figure was reached.[193] In its submittal, Ameren Illinois explained the costs as "3.5% for Evaluation, Measurement & Verification activities ("EM&V"), 5% for program implementation oversight; portion of the costs to conduct the potential study (estimated at $1.5 million), ~3% for education and awareness activities as well as planning, assessment and tracking of the programs, as required under Section 5/16-111.5B."

Administrative costs were a contested issue in the litigation of the 2015 Plan. In response to arguments that Ameren Illinois' blanket administrative adder of 15% was both inflated and inadequately justified, the Commission directed the utilities "to track administrative costs by program in order to aid in future determinations of appropriate administrative cost assumptions."[194] In light of this directive, the IPA believes that including fixed, non-incremental, non-program-specific costs in the TRC calculation such as those for Ameren's potential study (the development of which is a standalone requirement under Section 16-111.5B(a)(3)(A), and must occur whether Ameren Illinois administers 10, 30, or zero energy efficiency programs) is inappropriate and inconsistent with the direction taken by the Commission in Docket No. 14-0588. If unidentified costs and costs associated with Ameren Illinois' potential study are removed, the administrative cost adder would then constitute 11.5% -- coincidentally, the same amount reported by ComEd in its submittals. Section 7.1.5.5 lists the TRC results as submitted by Ameren Illinois, and the TRC as adjusted by the IPA to reflect an 11.5% administrative adder.

For its 2016 Plan submittal, Ameren Illinois removed its prior-applied blanket adder for Non-Energy Benefits ("NEBs") from the TRC.[195] This is somewhat similar to ComEd's approach, as ComEd does not include a blanket NEB adder (ComEd does, however, include some measure-specific adders as described further in Section 7.1.6.2). According to Ameren Illinois, the removal of a non-energy benefits adder was in response to feedback during the bid review process from ICC staff. Ameren also did not include DRIPE (see Section 7.1.2.2.2 above for a discussion of this issue) in its calculations.

The IPA conducted a sensitivity analysis of the Ameren Illinois-provided TRC results looking at the impact of the administrative adder set at 0% (as done by ComEd), 7%, and 11.5% as described above, and 13.58% as proposed by Ameren Illinois; and through including or excluding NEBs at Ameren Illinois' prior-applied levels. Various combinations of these adjustments only impacted the TRC results of three programs that would have otherwise failed the TRC. In two of the cases, adding in NEBs would have increased the TRC to above 1.0 even with a 13.58% administrative adder (rising from 0.97 to 1.06, and from 0.93 to 1.02). Without

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[193] Appendix B, Ameren Illinois Section 16-111.5B Submittal at 9-10.
[194] Docket No. 14-0588, Final Order dated December 17, 2014 at 224.
[195] The IPA understands Ameren Illinois as having previously used a 10% blanket adder for electric savings and a 7.5% adder for gas savings, including in last year's Section 16-111.5B filing.

NEBs, both of those programs would fail the TRC test with an 11.5% or a 7% administrative adder, but would both pass with a 0% administrative adder (at 1.0 and 1.05 respectively). The third program would only pass the TRC test with NEBs included and a 0% administrate adder.

For purposes of this draft Plan, the IPA has chosen not to include these three programs in its recommended programs for inclusion, but invites interested parties to comment on what administrative adder should be used, and if a NEBs adder should be included (and if so, at what level). Based on comments received, the IPA will consider if its recommendation should change or remain the same.

As described above in Section 7.1.5.2, Ameren Illinois (through its consultant AEG) adjusted certain net-to-gross ratios provided by bidders to more accurately reflect values in the Illinois TRM. Those adjustments appear to be reasonable to the IPA.

The IPA observes that fewer programs passed the Ameren Illinois TRC screening than the ComEd screening. While this could be a function of the bids received or the TRC methodology applied, it appears that lower energy and capacity prices in the Ameren Illinois service territory simply make the test more difficult to pass.

7.1.5.3 Programs for which Ameren Illinois asserts the cost exceeds the cost of supply

As described in Section 7.1.2.2 of the Plan, Section 16-111.5B of the PUA requires the IPA to include incremental "energy efficiency programs and measures it determines are cost-effective."[196] Under Section 16-111.5B, "the term 'cost-effective' shall have the meaning set forth in subsection (a) of Section 8-103 of this Act,"[197] meaning "that the measures satisfy the total resource cost test."[198]

The total resource cost test is a distinct test from the "cost of supply." Nevertheless, in its 2016 Plan submittal, Ameren Illinois suggests that two programs which pass the TRC (even using Ameren's suggested inputs and input levels) should still be excluded "because the estimated costs of such programs are not less than the prevailing cost of supply."[199]

The IPA disagrees with this approach. Illinois law requires the inclusion of programs that the IPA determines to be "cost-effective" through application of the TRC test. Ameren Illinois based their suggestion on Section 16-111.5B(a)(3)(E), which requires the utilities to include an "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" as part of their Section 16-111.5B submittal. However, this requirement does not create independent grounds for the exclusion of otherwise <u>cost-effective</u> programs in an IPA Plan. Indeed, the Commission is likewise directed to "approve the energy efficiency programs and measures included in the procurement plan, including the annual energy savings goal, if the Commission determines they fully capture the potential for all achievable <u>cost-effective</u> savings, to the extent practicable, and otherwise satisfy the requirements of Section 8-103 of this Act." This statutory cost-effectiveness threshold cannot simply be read out of the law in favor of a utility's preferred alternative approach.[200]

In addition, how to interpret "the prevailing cost of comparable supply" language found in Section 111.5B(a)(3)(E) has already been addressed by parties through the workshop process. As can be found in the Staff Report summarizing the 2013 Section 16-111.5B workshops, this language "can be interpreted as the

[196] 220 ILCS 5/16-111.5B(a)(4).
[197] 220 ILCS 5/16-111.5B(b).
[198] 220 ILCS 5/8-103(a).
[199] Appendix B, Ameren Illinois Section 16-111.5B Submittal at 22.
[200] In its submittal, Ameren Illinois relies on the phrase "to the extent practicable" as justification for fashioning non-statutory limitations on program inclusion, and then conflates "<u>practicable</u>" (used only initially in their submittal when quoting the law) with "<u>practical</u>" (used instead throughout its submittal). While "practicable" refers to "capable of being accomplished," "practical" means to "being likely to be effective." A cost-effective program submitted in compliance with RFP requirements is unquestionably part of a portfolio intended to "fully capture the potential for all achievable <u>cost-effective</u> savings, to the extent <u>practicable</u>." There may be "practical" reasons for a utility to seek a program's exclusion, but as Section 16-111.5B fails to use the term "practical," those find no support in the law.

total resource cost test."[201] As the "cost of supply" analysis conducted by Ameren Illinois did not follow the established strictures of the total resource cost test (for instance, by not including avoided transmission and distribution costs for the proposed cost-effective energy efficiency measures, despite such costs clearly being avoided), it appears to be inconsistent with the consensus approach decided upon in 2013.

Based on the foregoing, the IPA declines to adopt Ameren Illinois' recommendation regarding the exclusion of cost-effective energy efficiency programs which exceed the "cost of supply" but pass the total resource cost test required for evaluation by the law.

7.1.5.4 Review of 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, "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 for duplicative or competing bids approved by the Commission works 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 determine 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.[202]

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

[201] http://www.icc.illinois.gov/downloads/public/ICC%20Staff%20Report%20Summary%20of%20Section%2016-111.5B%20EE%20Workshops%202013-08-02.pdf

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

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.[203]

The IPA concurs with the determinations of Ameren Illinois and its Stakeholder review committee that the following programs meet the duplicative standard set out in previous Procurement Plans and Commission Orders. Therefore the IPA does not recommend the approval of these programs.

Table 7-2: Ameren Illinois Duplicative Program Screening

Sector	Program	Reason Duplicative
Residential	Direct Install – LED and Smart Strips	Duplicative with Ameren Illinois Section 8-103 Home Performance and HVAC Programs, and DCEO Section 8-103 Low Income Program
Residential	School Kits	Duplicative with Ameren Illinois Section 8-103 School Kits Program
Business	Direct Install - LED Only	Duplicative with Ameren Illinois Section 16-111.5B Small Business Direct Install Program
Business	Direct Install - Private Schools	Duplicative with Ameren Illinois Section 8-103 Standard Program and Ameren Illinois Section 16-111.5B Small Business Direct Install Program
Business	Direct Install - Geo-Targeted	Duplicative with Ameren Illinois Section16-111.5B Small Business Direct Install Program and DCEO Section 8-103 Direct Install Program
Business	Direct Install - Whole Building	Duplicative with Ameren Illinois Section 16-111.5B Small Business Direct Install Program, Ameren Illinois Section 8-103 Standard Program, and DCEO Section 8-103 STEP Program
Business	Rural Efficiency Kits	Duplicative to Ameren Illinois 8-103 Standard Program

Two additional programs were considered duplicative of current DCEO programs, for which future funding is uncertain. Both programs target public buildings. The Direct Install – Public Facilities program was also considered to be potentially duplicative of the existing Small Business direct install program.

Table 7-3: Ameren Illinois Programs Duplicative of DCEO Programs

Program	Net Savings (MWh)	Total Utility Cost	TRC
Direct Install - Public Facilities	29,314,681	$6,614,516	1.31
Savings through Efficient Products	2,770,617	$776,553	1.09

If included, these programs would be due to start June 1, 2016. The State Fiscal Year runs from July 1 to June 30th of each year; thus the first month (and any associated preparation time) of DCEO's current programs (of which the programs identified above may be duplicative) falls into the current Fiscal Year July 1, 2015 through June 30, 2016. At the time of the release of this draft Plan, DCEO's budget for the current Fiscal Year has not yet been enacted. Without that budget in place, it is unclear whether any funding is available for DCEO to run energy efficiency programs in the current Fiscal Year or what the cascading repercussions may be on following Fiscal Years.

7.1.5.5 Ameren Illinois Programs Recommended for Approval

Ameren Illinois' submittal includes identification of nine energy efficiency offerings for this Procurement Plan with a TRC of above 1.0, which were not determined to be "duplicative" of existing programs, and which met

[203] Id.

the requirements of Ameren Illinois. All nine of these programs passed the TRC test at the time of assessment, even without adjustments made to Ameren Illinois' suggested TRC.[204] These programs are exhibited in Table 7-4.

Table 7-4: Ameren Illinois Energy Efficiency Offerings

Program	Net Savings (MWh)	Total Utility Cost	TRC (As submitted)	TRC[205] (IPA Adjusted)
Agricultural Energy Efficiency	945	$380,615	1.09	1.11
Community-Based CFL Distribution	9,330	$1,178,428	2.27	2.31
Demand Based Ventilation Fan Control	5,717	$1,227,357	3.38	3.44
Electric Only Behavior Modification	8,640	$373,920	1.06	1.06
HVAC Check-Up	5,940	$1,160,182	1.35	1.38
LED Linear Lighting for Small Facilities	14,750	$3,168,882	1.16	1.19
Private HVAC Optimization	7,692	$1,135,800	1.29	1.31
Public HVAC Optimization	7,692	$1,135,800	1.29	1.31
Small Commercial Lit Signage	9,417	$2,271,599	1.31	1.34

The total net savings for these programs is estimated as 70,124 MWh at the busbar[206]. The programs also contribute to a peak reduction of approximately 8.3 MW. The estimated savings attributable to eligible retail customers is 26,334 MWh.

7.1.5.6 Ameren Illinois Requested Determinations

In its filing, Ameren Illinois made the following requests:

> AIC[207] formally requests that annual updates to the measure values in the TRM and NTG ratio values result in changes to the implementer's savings goals and/or the cost structures between AIC and the implementer and will be re-negotiated for the savings calculations based upon the annual IL-TRM and NTG updates for one program year.
>
> AIC seeks express approval that it is permitted to recover costs that exceed the estimated program costs. In lieu of this express approval, AIC will be forced to prematurely discontinue approved programs prior to the estimated budget being expended.[208]

The IPA does not object to these requests, as they appear to be consistent with consensus items from past workshops.

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

7.1.6 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 2016 Procurement Plan at www.illinois.gov/ipa. Note that the document entitled "ComEd Third Party Efficiency

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[204] Ameren Illinois also provided the results of the UCT test and all the proposed programs passed the UCT test. The IPA considers that informational only and has not used the UCT test in its consideration of programs to include in this Plan.
[205] Using 11.5% administrative adder, as described in Section 7.1.5.2. Note that the adder is not applied to program incentives, only to direct costs so the impact of this adjustment varies by program. This adjustment does not include non-energy benefits.
[206] Note that in Ameren Illinois' submittal document net savings are primarily listed as at the meter. For consistency net savings in this plan are listed at the busbar.
[207] Ameren Illinois Company ("AIC").
[208] Ameren Illinois Section 16-111.5B Submittal at 12.

Program Results of 2015 Bid Review, July 13, 2015" contains confidential data and is not included with this Plan.

The IPA believes that ComEd's filing meets the requirements of Section 16-111.5B(a)(1)-(3) and the programs listed in Appendix C-2 should be approved pursuant to Section 16-111.5B(a)(5).

7.1.6.1 ComEd Bid Review Process

ComEd received 17 bids. One bid was withdrawn. The remaining programs included one multifamily program, one agricultural program, 8 business programs, three public-sector programs, and three low-income programs. The public sector programs and the low-income programs target customer segments normally served by DCEO Section 8-103 programs.

In order to provide the IPA with a broad range of feedback on the bids received, ComEd solicited involvement from members of the SAG. In addition to DCEO, two organizations participated in the review process: the Natural Resources Defense Council and the Environmental Law & Policy Center.

ComEd released its Section 16-111.5B RFP on March 9, 2015 and conducted a pre-bid conference on March 16. The review team participated in conference calls during the process to discuss bids, compare preliminary results, and identify follow-up information needed from bidders. ComEd's review focused on programs targeting customers served by the ComEd portfolio, although ComEd also reviewed the a Low Income Kits program, since ComEd Section 8-103 Energy Efficiency portfolio includes a similar program that would also be eligible to low income customers. Similarly, DCEO's review focused on programs targeting public sector and low income customers, although DCEO also reviewed the LED Linear Lighting for Small Facilities bid, since that proposal included targeting some public sector customers with its offering.

Of the 16 bids, four bids were determined to be duplicative of existing ComEd programs and one bid had a TRC below 1.0. This left 11 programs for inclusion in this Plan.

7.1.6.2 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 more detailed input and output tables from the analysis than in previous years, but 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).

As previously noted, ComEd has traditionally used marginal line losses when calculating TRCs, and that practice continued for its submittal this year. In previous years, ComEd also did not include an adder for administrative costs. For this Plan, ComEd included an administrative adder of 11.5%; this number was developed off of "an 8.5 percent adder to reflect ComEd's administrative costs and an additional 3 percent adder to reflect costs required by ComEd's independent evaluator."[209] ComEd also calculated TRC values without the inclusion of its administrative cost adder; for the one program that did not pass the TRC, removing the adder (which would increase the TRC value) did not result in the TRC being over 1.0 (instead, it was 0.93).

ComEd did not include DRIPE in its TRC calculations and does not include a blanket NEB adder at the portfolio or program level. ComEd instead considers NEBs at the measure level, adding the following benefits to measures as appropriate:

[209] "ComEd tracked costs over the past year and determined that administrative costs would add 8.5% to the typical third party program costs. In addition, stakeholders agreed that programs approved and run pursuant to 16-111.5B would incur an evaluation budget equal to 3% of approved program budgets. In total, ComEd increased each bidder's budget by 11.5% to accommodate estimated administrative and evaluation costs." ComEd Load Forecast at 28.

- Maintenance savings (primarily the avoided customer cost to replace incandescent/halogen lamps every 1000-2000 hours due to the longer life of LED or fluorescent lamps)
- Water savings (for those measures that save water).[210]

Based on the sensitivity analysis conducted for Ameren Illinois programs (such as the inclusion of a NEBs adder and the observed impacts on TRCs), it does not appear that the addition of a blanket NEBs adder (such as what was used by Ameren Illinois in previous years) would have allowed the one program that failed the ComEd TRC screening to have passed.

7.1.6.3 Review of Duplicative Programs

ComEd and its stakeholder review committee determined that the following four (out of the 16 evaluated proposals) were duplicative of existing programs. The approach used was comparable to that described in Section 7.1.5.4 above.

Table 7-5: ComEd Duplicative Program Screening

Sector	Program	Reason Duplicative
Business	Super Trade Ally	Duplicative with Section 16-111.5B Small Business Energy Services Program
Business	Linear LED	Duplicative with Section 16-111.5B Small Business Energy Services Program
Business	Integrated Energy Controls	Duplicative with Section 16-111.5B Small Business Energy Services Program
Business	Energy Dashboard	Duplicative with Section 16-111.5B Small Business Energy Services Program

Three of the proposals directly overlapped the ComEd Small Business Energy Services program in ways that would not offer additional consumer benefits. The fourth program provided a web-based dashboard for lead creation, but failed to demonstrate how it would sufficiently utilize that dashboard to reach under-served markets and offer measures in ways that would not be merely duplicative of the existing program. ComEd also noted that the dashboard replicated much of the functionality of its Building Energy Analyzer dashboard that is available to business customers with AMI meters.[211]

The committee also concluded that two other programs while having some overlap more appropriately fell into the category of competing programs in which they would not detract from the existing programs and thus were included.

The IPA agrees with those determinations.

The review committee also determined that the five programs that target sectors normally served by DCEO programs could be structured so as not to be duplicative of existing programs (regardless of if those programs continue to receive funding as discussed in relation to Ameren Illinois' programs in Section 7.1.5.4 above.). However, those programs may require additional coordination between DCEO and ComEd.

7.1.6.4 ComEd Identification of "Performance Risk"

ComEd identified six programs that it considered a "performance risk" based upon the review of ComEd, the Stakeholder review committee, and DCEO (where applicable). This analysis based upon an assessment of the strength of the proposed approach and the experience of the program team. One of those programs did not pass the TRC, and one was determined to be duplicative. Of the remaining four programs, ComEd expressed concerns that the sales cycle for the applicable products in two of the bids is very slow and complex, one program that expands on an existing program has currently not currently expended its budget, and another

[210] ComEd also includes a carbon cost adder as required by the statutory TRC definition.
[211] The Building Analyzer Dashboard is not funded through Section 8-103, so this duplication is not directly relevant to this determination of the program being duplicative.

program may rely on lists of customers receiving LIHEAP for marketing, and those lists are not available due to confidentiality provisions.

ComEd does not, however, recommend that such programs not be included in the IPA's Plan or not approved by the Commission. The IPA agrees. Section 16-111.5B requires the IPA to include incremental "energy efficiency programs and measures it determines are cost-effective."[212] Under Section 16-111.5B, "the term 'cost-effective' shall have the meaning set forth in subsection (a) of Section 8-103 of this Act,"[213] meaning "that the measures satisfy the total resource cost test."[214] As each of these measures passes the total resource cost test, they should be included in the IPA's annual procurement plan.

Further, as the IPA understands it, the "pay for performance" nature of contracts under Section 16-111.5B should insulate ratepayers from paying for programs that cannot achieved expected savings. If risk of non-performance rested with ratepayers or the administering utility, then qualitative program factors would need to be considered to protect those parties' interests. But under a pay for performance arrangement, the IPA understands risk of underperformance to rest with the winning bidders, and flawed program design will simply manifest itself in less payment for less performance.

However, while the IPA does not propose recommending exclusion or non-approval of any "savings risk" programs, it invites stakeholder comments on how a qualitative assessment of a program's proposed approach and program team may be considered and whether the "pay for performance" model is indeed sufficient to insulate ratepayers and utilities from financial risk. The IPA has invited feedback on the use of qualitative factors for energy efficiency program review in the past,[215] and is again interested in any such feedback this year.

7.1.6.5 ComEd Programs Recommended for Approval

ComEd's submittal includes identification of eleven energy efficiency programs for inclusion in this Procurement Plan. All of these programs passed the TRC test at the time of assessment.[216] These programs are exhibited in Table 7-6.

Table 7-6: ComEd Energy Efficiency Offerings

Program	Net Savings (MWh)	Total Utility Cost	TRC
Agricultural EE	1,354	$366,613	1.64
Assisted and Senior Housing	1,319	$625,928	1.60
Community-based CFL Distribution (DCEO)	17,566	$1,240,000	3.01
Efficient Products (DCEO)	3,711	$778,179	6.24
Enhanced Building Optimization (DCEO)	12,274	$2,500,000	2.68
Lit Signage	16,236	$3,700,000	3.06
Low-income Kits (DCEO)	4,555	1,439,246	1.85
Low-income Multi-family (DCEO)	7,239	$2,167,622	4.44
Luminaire-Level Lighting Control	19,113	$5,101,484	4.39
Monitoring-based Commissioning	3,008	$1553,800	1.67
Rural Small Biz EE Kits	1,078	$582,970	4.54

The net savings at the busbar is 87,453 MWh. These programs are forecasted to deliver 13 MW of reduction in peak procurement. The savings attributable to eligible retail customers is 35,812 MWh.

212 220 ILCS 5/16-111.5B(a)(4).
213 220 ILCS 5/16-111.5B(b).
214 220 ILCS 5/8-103(a).
215 Most recently, as part of the Agency's draft 2015 Plan.
216 ComEd also provided the results of the UCT test and eight of the ten proposed programs passed the UCT test. The IPA considers that informational only and has not used the UCT test in its consideration of programs to include in this Plan.

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

7.1.7 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. MidAmerican provided to the IPA information related to those provisions, which is included as Appendix D of this Plan.

Section 16-111.5B of the Public Utilities Act also provides that "each Illinois utility procuring power pursuant to [Section 16-111.5] shall annually provide to the Illinois Power Agency by July 15 of each year, or such other date as may be required by the Commission or Agency, an assessment of cost-effective energy efficiency programs or measures that could be included in the procurement plan."[217] To satisfy this requirement, ComEd and Ameren Illinois issue requests for proposal for third-party energy efficiency programs early in the year, receive detailed proposals from third-party vendors in the spring, screen those programs for cost-effectiveness and duplicity with existing programs, and disclose which programs the utility deems to be cost-effective for inclusion in the IPA's procurement plan as part of its July 15th deliverables.

"[P]rocurement plans prepared pursuant to Section 16-111.5 of this Act shall be subject to" Section 16-111.5B's "requirements," and a procurement plan for MidAmerican would unquestionably be "prepared pursuant to Section 16-111.5."[218] However, 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" and 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."[219] As Section 8-103 of the Public Utilities Act "does not apply to an electric utility that on December 31, 2005 provided electric service to fewer than 100,000 customers in Illinois" (i.e., MidAmerican),[220] there are no analyses developed by MidAmerican and no underlying MidAmerican energy efficiency programs under Section 8-103 to which any "new or expanded" programs could be viewed as "incremental."

Other provisions in Section 16-111.5B also call into question its applicability to MidAmerican. Section 16-111.5B(a)(3) requires that utilities "shall 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," but again, no plans are filed and no requests for proposals may be issued by a small multi-jurisdictional pursuant to Section 8-103.[221] Likewise, the Commission approves included incremental efficiency programs "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 this Act," but a "requirement" of Section 8-103 is that programs may not be proposed by small multi-jurisdictional utilities.[222]

Based on the foregoing, the IPA believes that MidAmerican's July 15, 2015 submittal meets the requirements of Section 16-111.5B as it applies to that utility. However, in comments this draft Plan, the IPA invites further feedback from interested parties on the applicability of Section 16-111.5B to MidAmerican for this Plan, and in the future.

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[217] 220 ILCS 5/16-111.5B(a)(3).
[218] 220 ILCS 5/16-111.5(a).
[219] 220 ILCS 5/16-111.5(a)(3)(B), (a)(3)(C).
[220] 220 ILCS 5/8-103(h).
[221] 220 ILCS 5/16-111.5B(a)(3).
[222] 220 ILCS 5/8-103(a)(5).

7.2 Procurement Strategy

The IPA recommends one slight refinement to the basic strategy for block energy procurement from the 2015 Procurement Plan. The slight refinement relates to the procurement for the November to May months which will now take place for October through May as explained below.

- The current 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 2016-2017 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 2016-2017 delivery year. A portion of the targeted hedge levels for the 2017-2018 and the 2018-2019 delivery years of 50% and 25%, respectively, will be acquired spread on an equal basis in the spring and fall procurement events.
- Including October in the fall procurement event will better align the procurement with the utilities' non-summer period and, more importantly, gives the utilities the opportunity to cover any short position in the month of October resulting from load returning to the utility which was not anticipated in the spring load forecast. For example, after the March 2015 load forecast was produced, the City of Chicago announced to return its municipal aggregation load to ComEd. This decision produced a short position in ComEd's supply portfolio in the months of June through October. Had the fall procurement event included the month of October, the short position would had been smaller. The IPA is not aware of any negative financial consequences resulting from the return of the Chicago load to ComEd; however, from a risk management perspective, it would have been preferable to have had the option of covering the month of October in the September procurement event.

The refined strategy is summarized in Table 7-7.

Table 7-7: Summary of Energy Hedging Strategy

Spring 2016 Procurement			Fall 2016 Procurement		
June 2016-May 2017 (Upcoming Delivery Year)	Upcoming Delivery Year+1	Upcoming Delivery Year+2	October 2016-May 2017	Upcoming Delivery Year + 1	Upcoming Delivery Year + 2
June 100% peak and off peak July and Aug. 106% peak, 100% off peak and Sep. 100% peak and off peak Oct. - May 75% peak and off peak	25%	12.5%	100%	25%	12.5%

Prior procurement plans, including the 2015 Procurement Plan, have recommended that ComEd continue to obtain its capacity needs through the PJM capacity market. In the current plan the IPA recommends that ComEd continue to obtain its capacity needs from the PJM capacity market as shown in Table 7.5.

Table 7-8: Summary of Capacity Procurement Strategy for ComEd

June 2016-May 2017 (Upcoming Delivery Year)	June 2017-May 2018	June 2018-May 2019
100% PJM RPM Auctions*	100% PJM RPM Auctions*	100% PJM RPM Auctions

* PJM RPM Base Residual Auctions for 2016-17 and 2017-18 have already cleared. PJM's initial Capacity Performance Resource auction will be completed by mid-September 2015.

For Ameren Illinois, the 2015 Procurement Plan recommended that for the 2015-2016 Planning Year, Ameren Illinois purchase all of its capacity requirements via MISO's PRA. This was the first year since the IPA was formed that Ameren Illinois had no forward hedging of capacity. The IPA recommends a slight change in strategy with respect to hedging capacity price risk for Ameren Illinois.

The capacity prices resulting from the 2015-2016 MISO PRA cleared substantially higher for the Illinois Region (Zone 4) than in prior years. The 2015-2016 Zone 4 price of $150/MW-Day is 9 times greater than the previous Planning Year, and more than 40 times greater than the other zones. MISO's Independent Market Monitor ("IMM") is forecasting a $71/MW-Day Initial Reference Price for 2016-2017[223] and a Preliminary Initial Reference Price of $136.37/MW-Day[224] for the 20172018 Planning Year. It is conceivable that the Zone 4 price will clear at close to these prices, i.e. dropping in 2016-2017 then rising again in 2017-2018. While the PJM Base Residual Auction (BRA) for 2018/19 has not been conducted yet, the capacity performance incentives will most likely result in an increase in the BRA price for 2018-2019.[225] With the MISO IMM using the opportunity cost of selling to PJM as a basis for deriving the Initial Reference Price it is safe to assume that the Initial Reference Price for 2018-2019 will be higher. As mentioned in Chapter 5, the IPA expects much uncertainty in future MISO PRA Zone 4 clearing prices. In the interest of hedging price risk and maintaining rate stability for the Illinois customers, the IPA recommends hedging a portion of Ameren's (and MidAmerican's) capacity market exposure.

The differences between the PJM and MISO capacity constructs indicates that a capacity hedging strategy that relies on both the MISO PRA as well as bilateral capacity procurements by the IPA is a reasonable hedging approach for meeting the Ameren Illinois capacity needs. One particularly important difference is that for the MISO PRA, the clearing prices are not known until two months prior to the beginning of the respective Planning Year, whereas in PJM the primary capacity auctions, the BRAs, are forward looking and are held three years prior to the Delivery Year. The MISO PRA therefore does not provide a forward price signal and poses potential risks to customers when prices increase abruptly and surprisingly, as observed in the 2015-2016 PRA.

In light of the short-term nature of the MISO PRA, it makes sense to utilize forward hedging of at least a portion of the Ameren Illinois capacity needs through bilateral capacity purchases. Given the potential scheduling conflicts with the MISO PRA and a spring IPA capacity procurement event, the capacity procurement for the upcoming Planning Year should take place well before the MISO PRA, during a fall procurement event. It is also important to note that an argument could be made that, given the results of the most recent MISO PRA, Zone 4 customers could incur higher prices through the bilateral purchases. Suppliers know from the MISO PRA results that the potential for higher capacity prices in Zone 4 may exist given a higher capacity clearing price in the PRA, such as occurred in the 2015-2016 PRA. Bidders in the IPA capacity procurement event would benefit from knowing recent MISO PRA clearing prices. In addition to PRA clearing prices being public knowledge, bidders would be aware of the input information utilized by the MISO IMM to develop the PRA Reference including: Initial Reference Prices, Conduct Thresholds[226], and the Cost of New Entry (CONE). However, given that any bids above the benchmark prices in an IPA procurement are rejected and the confidential nature of the inputs, methodology and values for the capacity benchmarks, the bidding advantage for the suppliers provided by detailed knowledge of the PRA results and assumptions would be somewhat diluted. The IPA capacity procurements also offer flexibility in that the procurements provide an

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[223] The 2016-2017 BRA price is $59.37/MW-Day.
[224] Forecast based on RPM BRA results for 2017-20/18 and presented at February 5, 2015 SAWG. The 2017-2018 BRA price is $120/MW-Day.
[225] The results of the 2018-2019 BRA are expected to be posted on August 21st, 2015.
[226] The Conduct Threshold = Initial Reference Price + 10% CONE.

option and not an obligation to execute contracts. For example, in the event the suppliers offer prices that exceed the benchmarks, it is possible that no contracts would be executed.

In light of the above discussion, Table 7-9 provides a capacity hedging strategy where:

- For the 2016-2017 Planning Year, 50 % of the Ameren Illinois capacity would be procured through an RFP in September 2015 with the remaining 50% being procured in the MISO PRA;
- For the 2017-2018 Planning Year, 25% of the Ameren Illinois capacity would be procured through an RFP in September 2015, 50% would be procured through an RFP in fall 2016, with the remaining 25% being procured in the MISO PRA; and
- For the 2018-2019 Planning Year, 25% of the Ameren Illinois capacity would be procured through an RFP in fall 2016, 50% would be procured through an RFP in fall 2017, with the remaining 25% being procured in the MISO PRA.

The IPA will review and analyze the results of the 2016-2017 MISO PRA and make any necessary adjustments to the recommended capacity hedging strategy in future procurement plans.

Table 7-9: Summary of Capacity Hedging Strategy for Ameren Illinois

June 2016-May 2017 (Upcoming Delivery Year)	June 2017-May 2018	June 2018-May 2019
50% RFP in Sep. 2015 50% MISO PRA*	25% RFP in Sep. 2015 50% RFP in fall 2016 25% MISO PRA**	25% RFP in fall 2016 50% RFP in fall 2017 25% MISO PRA***

* MISO Auction is expected to clear in April 2016.
** MISO Auction is expected to clear in April 2017.
***MISO Auction is expected to clear in April 2018.

MidAmerican made a formal request to the IPA to procure the incremental amount of capacity that is not currently served, or forecasted to be served in Illinois by MidAmerican-owned Illinois jurisdictional generation. As part of that request MidAmerican provided its forecasted load and capability, a summary of which is presented in Table 7-10.

The IPA notes that the magnitude of the proposed capacity procurements for MidAmerican is small relative to its capacity requirements (about 15%). Also, while the MISO PRA bidding and clearing dynamics that have been discussed for the Ameren procurement are potentially valid for Zone 3, it is unlikely that bidding behavior in this Zone will cause the level of price separation experienced in Zone 4 this year. The delivery point for MidAmerican's capacity is LRZ 3 (Zone 3); it cleared at $3.48/MW-Day in the 2015-2016 MISO PRA. In light of this, the IPA recommends that MidAmerican obtains 100% of its forecast capacity shortfall for the 2016-2017 Planning Year in the upcoming MISO PRA.

For future planning years, the IPA requests that the ICC approve the procurement of 100% of the 2017-2018 through 2020-2022 (five planning years) forecast capacity shortfall for MidAmerican in the fall 2016 procurement event, as shown in Table 7-11. This procurement will use the updated capacity requirements in MidAmerican's July 2016 load forecast, and will be subject to the review of the IPA and the consensus among the IPA, ICC Staff, MidAmerican, the and the Procurement Monitor. The IPA recommends consensus because the capacity requirements for the 2021-2022 delivery year will not be known until MidAmerican produces the July 2016 load forecast.

The IPA's overarching supply risk management approach relies, in part, on the laddered procurement strategy described in Chapter 6. However, in this specific case, the IPA recommends a five-year capacity procurement for MidAmerican for the following reasons. The capacity procurement volumes for MidAmerican are relatively small, as demonstrated in Table 7-10. The procurement cost of implementing a laddered procurement strategy for relatively small quantities each year would most likely outweigh the benefits. On the other hand, by combining the MidAmerican five-year capacity purchases with the Ameren Illinois capacity purchase in the fall 2016 procurement event, the procurement unit cost will be significantly lower as the result of economies of scale. Procuring all of MidAmerican's five-year capacity shortfall through the 2021-2022 delivery year may also result in lower capacity costs for MidAmerican over this planning horizon due to delays in coal retirements and the uncertainty associated with litigation over EPA emissions regulations. The recently finalized Clean Power Plan ("CPP") delayed requiring compliance until 2022 (the prior draft version had referenced 2020 as the initial mandated compliance date), which could delay some coal plant retirements. Further, likely litigation over the CPP may create additional uncertainty regarding the timing of coal plant retirements, potentially offering the opportunity to buy reasonably priced capacity in the near horizon. Finally, in support of a five-year bilateral capacity procurement, allowing for the procurement of capacity for a five-year period may provide enough revenue certainty for developers who would build or repower capacity in the Zone and help maintain reliability levels within prescribed standards.

Table 7-10: Summary of MidAmerican Load and Capability

	2016-2017	2017-2018	2018-2019	2019-2020	2020-2021
Coincident Peak MW Served by MidAmerican	440.2	442.9	445.9	448.9	451.8
MISO PRM	7.1%	7.1%	7.1%	7.1%	7.1%
Total PRMR MW	471.7	474.4	477.5	480.7	483.9
Total Net Capability MW	397.8	399.3	399.3	399.3	399.3
Surplus / Shortfall (UCAP MW)	(73.7)	(75.1)	(78.3)	(81.4)	(84.7)

Table 7-11: Summary of Capacity Hedging Strategy for MidAmerican

June 2016-May 2017 (Upcoming Delivery Year)	June 2017-May 2022
100% MISO PRA*	100% RFP in fall 2016

* MISO Auction is expected to clear in April 2016.

The IPA does not recommend conducting a bilateral capacity procurement as part of the spring procurement event given the relatively close timing with regard to the MISO PRA. Attempting to procure the Ameren Illinois or MidAmerican forecast capacity shortfall for the upcoming year in a spring procurement would, in all likelihood, not allow sufficient time to participate in the MISO PRA, which also functions as the capacity source of last resort to avoid MISO penalties. In addition, it is the IPA's view that increasing the time interval between the MISO PRA results being released and the IPA capacity procurement may have some beneficial impacts on the prices bid into the IPA procurement.

7.3 Indicative Quantities and Types of Products to be Procured

The following tables were constructed using the July 2015 Expected Load Forecasts (which exclude incremental energy efficiency programs) to provide indicative values for the 2016-2017 delivery year. The actual target procurement volumes will be calculated using the March 2016 and July 2016 Expected Load Forecasts for the spring and fall procurement events respectively. These forecasts are expected to include Approved Energy Efficiency Programs for both Ameren Illinois and ComEd. The following tables are calculated assuming no LTPPAs curtailments during the delivery periods, and rounded symmetrically to the nearest 25 MW block.

7.3.1 Ameren Illinois

7.3.1.1 Ameren Illinois Procurement Delivery Years 2016 - 2021

Table 7-12: Ameren Illinois Spring Procurement, Delivery Year 2016-2017 Preliminary Volumes*

	Expected Load (MW)		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		Current Contracted Supply (MW)		Anticipated Spring 2016 Purchases (MW)	
	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak
June-16	1,000	822	1,000	822	493	403	500	425
July-16	1,175	928	1,246	928	581	462	675	475
August-16	1,116	857	1,183	857	554	427	625	425
September-16	867	726	867	726	442	375	425	350
October-16	750	640	562	480	378	329	175	150
November-16	780	675	585	506	385	347	200	150
December-16	1,019	899	765	674	499	444	275	225
January-17	1,002	928	752	696	507	457	250	250
February-17	928	858	696	643	472	429	225	225
March-17	855	772	641	579	426	375	225	200
April-17	720	624	540	468	349	315	200	150
May-17	686	654	515	491	341	330	175	150

*Volumes to be adjusted using the March 2016 expected load forecast, which shall also include newly approved energy efficiency programs.

Table 7-13: Ameren Illinois Fall Procurement, October-May of Delivery Year 2016 - 2017, Preliminary Volumes*

	Expected Load (MW)		100% of Expected Load (MW)		Anticipated Contracted Supply (MW)**		Anticipated Fall 2016 Purchases (MW)	
	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak
October-16	750	640	750	640	553	479	200	150
November-16	780	675	780	675	585	497	200	175
December-16	1,019	899	1,019	899	774	669	250	225
January-17	1,002	928	1,002	928	757	707	250	225
February-17	928	858	928	858	697	654	225	200
March-17	855	772	855	772	651	575	200	200
April-17	720	624	720	624	549	465	175	150
May-17	686	654	686	654	516	480	175	175

*Volumes to be adjusted using the July 2016 expected load forecast, which shall also include newly approved energy efficiency programs.
**Including any purchases made in spring.

Table 7-14: Ameren Illinois Spring Procurement, Delivery Year +1 (2017-2018), Preliminary Volumes*

	Expected Load (MW)		50% of Expected Load (MW)		Current Contracted Supply (MW)		Anticipated Spring 2016 Purchases (MW)		Anticipated Fall 2016 Purchases (MW)	
	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak
June-17	1,010	819	505	410	243	203	125	100	125	100
July-17	1,182	927	591	464	306	237	150	125	125	100
August-17	1,122	858	561	429	279	227	150	100	125	100
September-17	876	730	438	365	219	173	100	100	125	100
October-17	754	637	377	319	199	157	100	75	75	75
November-17	784	677	392	339	185	172	100	75	100	100
December-17	1,019	909	510	455	252	217	125	125	125	125
January-18	1,006	930	503	465	253	236	125	125	125	100
February-18	939	856	469	428	222	204	125	100	125	125
March-18	869	771	434	386	229	196	100	100	100	100
April-18	728	621	364	310	194	144	75	75	100	100
May-18	694	654	347	327	166	155	100	75	75	100

*Volumes to be adjusted using the March 2016 expected load forecast, which shall also include newly approved energy efficiency programs.

Table 7-15: Ameren Illinois Spring Procurement, Delivery Year + 2 (2018-2019), Preliminary Volumes*

	Expected Load (MW)		25% of Expected Load (MW)		Current Contracted Supply (MW)		Anticipated Spring 2016 Purchases (MW)		Anticipated Fall 2016 Purchases (MW)	
	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak
June-18	1,015	830	254	208	45	50	100	75	100	75
July-18	1,187	921	297	230	29	38	125	100	150	100
August-18	1,128	860	282	215	29	52	125	75	125	100
September-18	892	731	223	183	46	46	100	75	75	50
October-18	761	633	190	158	71	86	50	25	75	50
November-18	793	677	198	169	85	97	50	25	75	50
December-18	1,029	910	257	228	77	67	100	75	75	75
January-19	1,006	936	251	234	78	86	75	75	100	75
February-19	939	861	235	215	72	79	75	75	100	50
March-19	877	774	219	193	83	92	75	50	50	50
April-19	732	617	183	154	90	98	50	25	50	25
May-19	700	654	175	163	66	80	50	50	50	25

*Volumes to be adjusted using the March 2016 expected load forecast, which shall also include newly approved energy efficiency programs.

7.3.1.2 Delivery Year + 3 and Delivery Year + 4 (2019-2020 and 2020-2021)

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 these years in this Procurement Plan.

7.3.2 ComEd

7.3.2.1 ComEd Procurement Delivery Years 2016 – 2021

Table 7-16: ComEd Spring Procurement, Delivery Year 2016-2017, Preliminary Volumes*

	Expected Load (MW)		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		Current Contracted Supply (MW)		Anticipated Spring 2016 Purchases (MW)	
	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak
June-16	2,921	2,331	2,921	2,331	1,465	1,161	1,450	1,175
July-16	3,459	2,825	3,666	2,825	1,739	1,402	1,925	1,425
August-16	3,299	2,620	3,496	2,620	1,661	1,309	1,825	1,300
September-16	2,483	2,058	2,483	2,058	1,237	1,030	1,250	1,025
October-16	2,209	1,825	1,657	1,369	1,114	916	550	450
November-16	2,503	2,130	1,877	1,598	1,253	1,054	625	550
December-16	2,844	2,459	2,133	1,844	1,430	1,221	700	625
January-17	2,859	2,506	2,145	1,879	1,422	1,248	725	625
February-17	2,659	2,322	1,994	1,742	1,327	1,167	675	575
March-17	2,377	2,066	1,783	1,549	1,184	1,035	600	525
April-17	2,141	1,831	1,606	1,373	1,082	914	525	450
May-17	2,205	1,829	1,654	1,372	1,115	918	550	450

*Volumes to be adjusted using the March 2016 expected load forecast, which shall also include newly approved energy efficiency programs.

Table 7-17: ComEd Fall Procurement, October-May of Delivery Year 2016-2017, Preliminary Volumes*

	Expected Load (MW)		100% of Expected Load (MW)		Anticipated Contracted Supply (MW)**		Anticipated Fall 2016 Purchases (MW)	
	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak
October-16	2,209	1,825	2,209	1,825	1,664	1,366	550	450
November-16	2,503	2,130	2,503	2,130	1,878	1,604	625	525
December-16	2,844	2,459	2,844	2,459	2,130	1,846	725	625
January-17	2,859	2,506	2,859	2,506	2,147	1,873	700	625
February-17	2,659	2,322	2,659	2,322	2,002	1,742	650	575
March-17	2,377	2,066	2,377	2,066	1,784	1,560	600	500
April-17	2,141	1,831	2,141	1,831	1,607	1,364	525	475
May-17	2,205	1,829	2,205	1,829	1,665	1,368	550	450

*Volumes to be adjusted using the July 2016 expected load forecast, which shall also include newly approved energy efficiency programs.
**Including any purchases made in spring.

Table 7-18: ComEd Spring Procurement, Delivery Year +1 (2017-2018), Preliminary Volumes*

	Expected Load (MW)		50% of Expected Load (MW)		Current Contracted Supply (MW)		Anticipated Spring 2016 Purchases (MW)		Anticipated Fall 2016 Purchases (MW)	
	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak
June-17	3,182	2,527	1,591	1,263	790	636	400	325	400	300
July-17	3,766	3,079	1,883	1,539	939	777	475	375	475	375
August-17	3,575	2,858	1,788	1,429	886	709	450	350	450	375
September-17	2,686	2,242	1,343	1,121	667	551	350	275	325	300
October-17	2,380	1,968	1,190	984	607	622	300	175	275	175
November-17	2,708	2,306	1,354	1,153	678	654	350	250	325	250
December-17	3,053	2,661	1,526	1,331	762	665	375	325	400	350
January-18	3,109	2,726	1,554	1,363	789	680	375	350	400	325
February-18	2,874	2,529	1,437	1,264	727	642	350	300	350	325
March-18	2,564	2,240	1,282	1,120	641	552	325	275	325	300
April-18	2,324	1,985	1,162	992	572	497	300	250	300	250
May-18	2,392	1,984	1,196	992	590	493	300	250	300	250

*Volumes to be adjusted using the March 2016 expected load forecast, which shall also include newly approved energy efficiency programs.

Table 7-19: ComEd Spring Procurement, Delivery Year + 2 (2018-2019), Preliminary Volumes*

	Expected Load (MW)		25% of Expected Load (MW)		Current Contracted Supply (MW)		Anticipated Spring 2016 Purchases (MW)		Anticipated Fall. 2016 Purchases (MW)	
	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak
June-18	3,182	2,564	795	641	94	106	350	275	350	250
July-18	3,786	3,091	946	773	61	80	450	350	425	350
August-18	3,586	2,884	897	721	61	109	425	300	400	300
September-18	2,711	2,271	678	568	97	97	300	225	275	250
October-18	2,401	1,981	600	495	150	180	225	150	225	175
November-18	2,738	2,330	685	582	178	204	250	200	250	175
December-18	3,075	2,678	769	670	162	140	300	275	300	250
January-19	3,115	2,738	779	684	164	180	300	250	325	250
February-19	2,878	2,543	719	636	152	167	275	225	300	250
March-19	2,568	2,247	642	562	174	194	225	175	250	200
April-19	2,341	1,991	585	498	188	205	200	150	200	150
May-19	2,405	1,990	601	497	140	168	225	175	225	150

*Volumes to be adjusted using the March 2016 expected load forecast, which shall also include newly approved energy efficiency programs.

7.3.2.2 Delivery Year + 3 and Delivery Year + 4 (2019-2020 and 2020-2021)

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 these years in this Procurement Plan.

7.3.3 MidAmerican

7.3.3.1 MidAmerican Procurement Delivery Years 2016 – 2021

Table 7-20: MidAmerican Spring Procurement, Delivery Year 2016-2017, Preliminary Volumes*

	Expected Load (MW)		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		Current Contracted Supply (MW)		Anticipated Spring 2016 Purchases (MW)	
	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak
June-16	303	233	303	233	243	175	50	50
July-16	338	260	358	260	268	207	100	50
August-16	317	241	336	241	257	182	75	50
September-16	274	218	274	218	233	173	50	50
October-16	253	193	189	145	219	160	-	-
November-16	244	188	183	141	219	173	-	-
December-16	270	220	202	165	236	195	-	-
January-17	276	225	207	168	267	221	-	-
February-17	269	221	202	166	256	214	-	-
March-17	253	205	190	153	236	182	-	-
April-17	250	196	187	147	175	150	-	-
May-17	240	193	180	145	185	130	-	25

*Volumes to be adjusted using the March 2016 expected load forecast.

Table 7-21: MidAmerican Fall Procurement, October-May of Delivery Year 2016-2017, Preliminary Volumes*

	Expected Load (MW)		100% of Expected Load (MW)		Anticipated Contracted Supply (MW)**		Anticipated Fall 2016 Purchases (MW)	
	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak
October-16	253	193	253	193	219	160	25	25
November-16	244	188	244	188	219	173	25	25
December-16	270	220	270	220	236	195	25	25
January-17	276	225	276	225	267	221	-	-
February-17	269	221	269	221	256	214	-	-
March-17	253	205	253	205	236	182	25	25
April-17	250	196	250	196	175	150	75	50
May-17	240	193	240	193	185	155	50	50

*Volumes to be adjusted using the July 2016 expected load forecast, which shall also include newly approved energy efficiency programs.
**Including any purchases made in spring.

Table 7-22: MidAmerican Spring Procurement, Delivery Year +1 (2017-2018), Preliminary Volumes*

	Expected Load (MW)		50% of Expected Load (MW)		Current Contracted Supply (MW)		Anticipated Spring 2016 Purchases (MW)		Anticipated Fall 2016 Purchases (MW)	
	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak
June-17	300	238	150	119	243	177	-	-	-	-
July-17	341	259	170	130	259	195	-	-	-	-
August-17	315	245	158	123	261	186	-	-	-	-
September-17	276	221	138	111	235	176	-	-	-	-
October-17	252	193	126	96	211	156	-	-	-	-
November-17	249	186	124	93	215	170	-	-	-	-
December-17	273	222	136	111	248	190	-	-	-	-
January-18	276	224	138	112	266	215	-	-	-	-
February-18	270	221	135	111	249	198	-	-	-	-
March-18	255	206	127	103	231	179	-	-	-	-
April-18	250	195	125	97	177	144	-	-	-	-
May-18	241	193	120	97	185	131	-	-	-	-

*Volumes to be adjusted using the March 2016 expected load forecast, which shall also include newly approved energy efficiency programs.

Table 7-23: MidAmerican Spring Procurement, Delivery Year + 2 (2018-2019), Preliminary Volumes*

	Expected Load (MW)		25% of Expected Load (MW)		Current Contracted Supply (MW)		Anticipated Spring 2016 Purchases (MW)		Anticipated Fall 2016 Purchases (MW)	
	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak
June-18	304	239	76	60	245	180	-	-	-	-
July-18	338	261	84	65	270	198	-	-	-	-
August-18	317	245	79	61	254	183	-	-	-	-
September-18	279	222	70	55	236	176	-	-	-	-
October-18	253	192	63	48	208	156	-	-	-	-
November-18	250	187	62	47	213	170	-	-	-	-
December-18	272	224	68	56	234	185	-	-	-	-
January-19	279	223	70	56	266	214	-	-	-	-
February-19	271	222	68	56	258	202	-	-	-	-
March-19	257	209	64	52	168	137	-	-	-	-
April-19	250	194	63	49	149	140	-	-	-	-
May-19	242	195	60	49	217	164	-	-	-	-

*Volumes to be adjusted using the March 2016 expected load forecast, which shall also include newly approved energy efficiency programs.

7.3.3.2 Delivery Year + 3 and Delivery Year + 4 (2019-2020 and 2020-2021)

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 these years in this Procurement Plan.

7.4 Ancillary Services, Transmission Service and Capacity Purchases

7.4.1 Ancillary Services and Transmission Service

Ameren Illinois, MidAmerican, and ComEd purchase their ancillary services and transmission services from their respective RTOs, MISO and PJM. The utilities also manage their Financial Transmission Rights (FTR) processes 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.

7.4.2 Capacity Purchases

For ComEd, the IPA concludes that it does not need to include any extraordinary measures in the 2016 Procurement Plan to assure reliability over the planning horizon. The IPA recommends that ComEd continue to meet all of its capacity obligations through the PJM capacity market in which capacity is purchased in a three-year ahead forward market through mandatory capacity rules.

For Ameren Illinois, the IPA recommends the procurement of part of the capacity needs via forward hedging of at least a portion of the Ameren Illinois capacity needs through bilateral capacity purchases indicated in Table 7-9 (specific quantities to be finalized based on Ameren's forecast of July 2016). The remainder of the capacity needs will be procured from the MISO PRA. The Capacity Hedging Strategy for Ameren Illinois is reproduced in Table 7-24 below.

Table 7-24: Summary of Capacity Hedging Strategy for Ameren Illinois

June 2016-May 2017 (Upcoming Delivery Year)	June 2017-May 2018	June 2018-May 2019
50% RFP in Sep. 2015 50% MISO PRA*	25% RFP in Sep. 2015 50% RFP in fall 2016 25% MISO PRA**	25% RFP in fall 2016 50% RFP in fall 2017 25% MISO PRA***

* MISO Auction is expected to clear in April 2016.
** MISO Auction is expected to clear in April 2017.
***MISO Auction is expected to clear in April 2018.

For MidAmerican, the IPA concludes that, MidAmerican should obtain 100% of its forecast capacity shortfall for the 2016-2017 Planning Year from the MISO PRA. The IPA also requests that the ICC pre-approve the procurement of 100% of the 2017-2018 through 2021-2022 (five planning years) forecast capacity shortfall for MidAmerican, in a fall 2016 procurement event, as shown in the Table 7-25 using the updated capacity requirements in MidAmerican's July 2016 load forecast, and subject to the review of the IPA and consensus among the IPA, ICC Staff, MidAmerican, the and the Procurement Monitor. The IPA recommends consensus because the capacity requirements for the 2021-2022 delivery year will not be known until MidAmerican produces the July 2016 load forecast. The IPA recommends a five-year capacity procurement for MidAmerican for the reasons presented in Section 7.2.

Table 7-25: Summary of Capacity Hedging Strategy for MidAmerican

June 2016-May 2017 (Upcoming Delivery Year)	June 2017-May 2022
100% MISO PRA*	100% RFP in fall 2016

* MISO Auction is expected to clear in April 2016.

7.5 Demand Response Products

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

> 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.

ComEd provided information regarding its existing demand response programs for 2015 which include:

- Direct Load Control ("DLC"): ComEd's residential central air conditioning cycling program is a DLC program with 72,900 customers with a load reduction potential of 88 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 1,171 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.
- 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 commences with the 2015 Planning Year. ComEd sold 48 MW of capacity from the program into the PJM capacity auction for the 2017 Planning Year and 10 MW for the summer of 2015.

Ameren Illinois has implemented Voltage Optimization Program including, for example, Conservation Voltage Reduction ("CVR") Program, as well as Real Time Pricing ("RTP") and the associated Power Smart Pricing ("PSP") Program. Also, Ameren Illinois offers real time pricing options through its tariff (Ameren Rider RTP), and, pursuant to the Commission's Interim Order in Docket No. 13-0105, Ameren Illinois offers a Peak Time Rebate program (Rider PTR). 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 19.5 MW.

The IPA does not propose any procurement of demand response programs for the 2016-2017 delivery year. Under current market and regulatory conditions,[227] a new demand response procurement by the IPA would not meet the standards set forth in Section 16-111.5(b)(3) of the Public Utilities Act including, but not limited to, not being "cost effective," "satisfy[ing] the demand-response requirements of the regional transmission organization market in which the utility's service territory is located," or "provid[ing] for customers' participation in the stream of benefits produced by the demand-response products." 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 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.

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[227] In particular the pending Supreme Court case referenced in Section 2.7.

7.6 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.[228] As a part of the goal, the Plan must also include electricity generated from clean coal facilities.[229] While there is a broader definition of "clean coal facility" contained in the definition section of the IPA Act[230], Section 1-75(d) describes two special cases: the "initial clean coal facility"[231] 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").[232] 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.

7.6.1 FutureGen 2.0

In Docket No. 12-0544, the Commission approved inclusion of FutureGen 2.0 as a retrofit clean coal resource starting in the 2017 delivery year.[233] 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).[234]

However, 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. On May 26, 2015 the Illinois Senate adopted SR 232 which urges the U.S. DOE to continue funding Future Gen 2.0 and to extend the ARRA deadline for funding. At the time this draft Plan is being published for comment, the Agency is unaware of any change in status of the FutureGen 2.0 project, its underlying financing, and performance under the FutureGen 2.0 sourcing agreements.

7.6.2 Sargas

In preparation for its 2015 Plan, the Agency was approached by a team representing Sargas, Inc., a US subsidiary of Sargas AS, a Norwegian technology company, about its plans to develop a coal-fired power plant in Mattoon designed to burn Illinois coal with 90% post-combustion carbon capture, with captured carbon then used for local enhanced oil recovery. Sargas proposed that the IPA conduct a competitive procurement for clean coal facility sourcing agreements pursuant to its authority under Section 1-75(d)(1) of the IPA Act as a means to facilitate the project's development.

For reasons explained by the Agency in its 2015 Plan,[235] the IPA declined to adopt that proposal. In approving the IPA's 2015 Procurement Plan, the Commission approved that decision, stating that it was "not convinced that a proposal of the type presented by Sargas was contemplated by the Illinois General Assembly or is in the public interest."[236]

Based on a recent meeting with representatives from Sargas, the Agency understands that Sargas may make a similar proposal in comments on the IPA's draft 2016 Plan. The IPA will provide a response to the proposals made by Sargas, and any other parties providing comment on the Agency's draft Plan, through the Agency's 2016 Procurement Plan filed with the Illinois Commerce Commission.

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[228] 20 ILCS 3855/1-75(d).
[229] 20 ILCS 3855/1-75(d)(1).
[230] 20 ILCS 3855/1-10.
[231] Id.
[232] 20 ILCS 3855/1-75(d)(5).
[233] 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).
[234] Commonwealth Edison Co. v. Illinois Commerce Commission, et al., 2014 IL App (1st) 130544, July 22, 2014.
[235] See 2015 IPA Procurement Plan at 93-95.
[236] See Docket No. 14-0588, Final Order dated December 17, 2014 at 315.

7.7 Summary of Strategy for the 2015 Procurement Plan

Table 7-26 summarizes the recommendations of this Chapter.

Table 7-26: Summary of Procurement Plan Recommendations Based on July 15, 2015 Utility Load Forecast (Quantities to be Adjusted Based on the March and July 2016 Load Forecast):

	Delivery Year	Energy	Capacity	Renewable Resources	Ancillary Services
AMEREN ILLINOIS	**2016-2017**	Up to 675MW forecasted requirement (Spring Procurement) Up to 250MW additional forecasted requirement (Fall Procurement)	50% RFP in Sep. 2015 50% MISO PRA	One-year SRECs procurement up to 34.2GWh Five-year DG REC procurement up to 7.8GWh* No RPS procurement or sales for other resources, target exceeded	Will be purchased from MISO
	2017-2018	Up to 150MW forecasted requirement (Spring Procurement) Up to 125MW forecasted requirement (Fall Procurement)	25% RFP in Sep. 2015 50% RFP in Fall 2016 25% MISO PRA	No RPS procurement: shortage of 52.8 GWh, revisit next year	Will be purchased from MISO
	2018-2019	Up to 125MW forecasted requirement (Spring Procurement) Up to 150MW forecasted requirement (Fall Procurement)	25% RFP in Fall 2016 50% RFP in Fall 2017 25% MISO PRA	No RPS procurement: shortage of 413.4GWh, revisit next year	Will be purchased from MISO
	2019-2020	No energy procurement required	No further action at this time	No RPS procurement: shortage of 522.7GWh, revisit next year	Will be purchased from MISO
	2020-2021	No energy procurement required	No further action at this time.	No RPS procurement: shortage of 633.1GWh, revisit next year	Will be purchased from MISO
COMED	**2016-2017**	Up to 1,925MW forecasted requirement (Spring Procurement) Up to 725MW additional forecasted requirement (Fall Procurement)	100% PJM RPM Auctions	One-year SRECs procurement up to 69.9GWh Five- year DG REC procurement up to 16.3GWh* Total renewables are 68GWh short of target	Will be purchased from PJM
	2017-2018	Up to 475MW forecasted requirement (Spring Procurement) Up to 475MW forecasted requirement (Fall Procurement)	100% PJM RPM Auctions	No RPS procurement: shortage of 827.7GWh, revisit next year	Will be purchased from PJM
	2018-2019	Up to 450 MW forecasted requirement (Spring Procurement) Up to 425MW forecasted requirement (Fall Procurement)	100% PJM RPM Auctions	No RPS procurement: shortage of 1,616.6GWh, revisit next year	Will be purchased from PJM
	2019-2020	No energy procurement required	No further action at this time	No RPS procurement: shortage of 2,182.4GWh, revisit next year	Will be purchased from PJM
	2020-2021	No energy procurement required	No further action at this time	No RPS procurement: shortage of 2,527.7GWh, revisit next year	Will be purchased from PJM

MIDAMERICAN	**2016-2017**	Up to 100MW forecasted requirement (Spring Procurement) Up to 75MW additional forecasted requirement (Fall Procurement)	100% MISO PRA	One-year SRECs procurement up to 13.2GWh Five- year DG REC procurement up to 2.2GWh Total renewables are 220.4GWh short of target. Includes 165.3GWh of wind, 13.2GWh of solar and 2.2GWh of DG	Will be purchased from MISO
	2017-2018	No energy procurement required	100% RFP in Fall 2016**	No RPS procurement: shortage of 258.9GWh, revisit next year	Will be purchased from MISO
	2018-2019	No energy procurement required	100% RFP in Fall 2016**	No RPS procurement: shortage of 289.3GWh, revisit next year	Will be purchased from MISO
	2019-2020	No energy procurement required	100% RFP in Fall 2016**	No RPS procurement: shortage of 320.5GWh, revisit next year	Will be purchased from MISO
	2020-2021	No energy procurement required	100% RFP in Fall 2016**	No RPS procurement: shortage of 351.9GWh, revisit next year	Will be purchased from MISO

*The total DG RECs to be procured will be adjusted based on the results of the Fall 2015 DG procurement event.
** The fall 2016 capacity procurement will cover five planning years, starting with the 2017-18 Planning Year and ending with the 2021-2022 Planning Year.

8 Renewable Resources Availability and Procurement

This Chapter focuses on the procurement of renewable resources on behalf of eligible retail customers and also provides informational guidance on the IPA's considerations for the use of the Renewable Energy Resources Fund ("RERF") which contains payments made by ARES as part of their RPS compliance obligations. Procurement on behalf of eligible retail customers is subject to targets for purchase volumes and upper limits on customer bill impacts, which, based on the load forecast, creates a cap on the available budget for each utility.

From 2009 through 2012, the IPA's annual electricity procurement plans included purchase of renewable energy resources sufficient to meet the Renewable Portfolio Standard ("RPS") requirements applicable to the eligible load of ComEd and Ameren Illinois. In 2013 and 2014, the IPA determined that resources under contract were sufficient to meet the reduced eligible load, while in 2015 the IPA procured only Solar Renewable Energy Credits, and plans to procure resources from Distributed Generation this fall. For the 2016 Plan, in addition to any renewable energy credit procurements to meet the RPS targets for Ameren Illinois and ComEd, the IPA will seek to procure sufficient renewable energy credits to meet the renewable resources target for MidAmerican based on MidAmerican's total Illinois jurisdictional load.

MidAmerican's involvement in the 2016 Plan raises new questions about how to calculate the renewable resource target appropriate to it. Specifically, it is unclear whether renewable energy resources procurement targets should be calculated for <u>all</u> of Mid-American's eligible retail customer load, or <u>only</u> for <u>that portion</u> of 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."[237] While Section 16-111.5(a) defines "eligible retail customer" by customer status that would appear to include Mid-American's entire eligible retail customer load, this same section also expressly contemplates that Mid-American 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."[238]

In communications with the Agency, MidAmerican has stated that its interpretation of Section 16-111 of the PUA is that the amount of RECs to be procured by the IPA should be determined based on the incremental amount of energy and capacity planned to be procured by the IPA to serve MidAmerican's eligible Illinois customers, rather than the load for all of its eligible customers in Illinois. Under MidAmerican's viewpoint, because a small jurisdictional utility may elect for the IPA to procure only a portion of the energy and capacity required for its eligible customers, the IPA would likewise procure RECs to match the procurement of this incremental energy and capacity.

Alternatively, the IPA believes that the stronger argument may be that MidAmerican's renewable resource targets are determined based upon MidAmerican's "total supply to serve eligible retail customers"—in other words, its entire eligible retail customer load. While procurement may be requested by a small, multi-jurisdictional utility for only a portion of that load, the renewable energy procurement target itself is set through the more direct language contained in Section 1-75(c)(1) of the IPA Act ("a minimum percentage of each utility's total supply to serve the load of eligible retail customers"), and that language remains controlling regardless of whether the broader procurement is for only a portion of eligible retail customer load. Because the IPA believes that this may be the appropriate reading of the law, renewable energy resource procurement targets reported in this Chapter are calculated consistent with this approach. However, as these provisions are open to multiple interpretations, the IPA invites comments from interested stakeholders to aid with making its recommendation for its filed 2016 Procurement Plan.

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[237] 20 ILCS 3855/1-75(c)(1) (emphasis added).
[238] 220 ILCS 5/16-111.5(a).

After the Plan is filed, the Illinois Commerce Commission will make the final determination of whether the IPA's proposed procurement plan meets the requirements of Illinois law—including proposed renewable energy resources procurement proposals and targets. If the Commission determines that the MidAmerican renewable energy resource procurement should cover only the incremental portion of MidAmerican's eligible customer load, the quantity of RECs to be procured will be approximately 14% of the quantity that would be needed to cover the utility's total eligible customer load (as reported in this Chapter).

Section 1-75(c) 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, the following are the percentages of renewable energy resources required to be procured.[239] The renewable energy resources obligation for the utilities in the 2016-2017 delivery year is 11.5% to meet the June 1, 2016 target. This obligation increases by at least 1.5% each year thereafter to at least 25% by June 1, 2025.[240]

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."[241] Under this standard, if a procurement of RECs is scheduled to take place in Spring 2016 for delivery in the 2016-2017 delivery year, the most recently completed year (i.e., the year "ending immediately prior to the procurement") is the 2014-2015 delivery year, as the 2015-2016 delivery year would not have ended prior to the procurement. As a result, customer switching taking place in the fall of 2015 may not manifest itself in significant changes to renewable energy procurement targets until procurements take place in the spring of 2017 for the 2017-2018 delivery year. However, that switching will be reflected in the actual 2015-2016 delivery year load.[242]

In addition, the RPS mandate includes targets for specific resource types: 75% wind, 6% (by June 1, 2015 and thereafter) photovoltaics ("PV") and 1% (by June 1, 2015 and thereafter) distributed generation ("DG") which can be included within the PV and wind requirements. [243]

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 kilowatthour by those customers during the year ending May 31, 2007 or the incremental amount per kilowatthour paid for these resources in 2011.[244]

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' expected load forecasts as

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[239] 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.
[240] 20 ILCS 3855/1-75(c)(1).
[241] 20 ILCS 3855/1-75(c)(2).
[242] These quantities are updated with each Plan's load forecast and will change as those forecasts are updated. For example, comparing the ComEd total REC target for the 2016-2017 delivery year in the 2015 Plan to this Plan shows little change, but for the 2017-2018 delivery year the target is 20% higher, and for the following year 34% higher. This reflects the impact of revising the load forecast to account for the decrease in switching due to the expiration of municipal aggregation contracts. The changes are much less significant for Ameren Illinois.
[243] 20 ILCS 3855/1-75(c)(1).
[244] 20 ILCS 3855/1-75(c)(2)(E).

described in Chapter 3 and recommended by the IPA to be adopted by the ICC. If the ICC were to adopt a different load forecast, then the analysis which follows in this Chapter would have to be revised accordingly. In future procurement plans, load forecasts will be updated based on new data (particularly eligible retail customer switching rates). Therefore the renewable resource and related budget estimates presented in future plans could differ significantly from what is presented in this Plan.

In recent years, Ameren Illinois and ComEd have generally met their overall RECs procurement targets. However, some years since 2012 have seen the utilities fall short of their 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 and wind 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), Ameren Illinois and ComEd had met their overall RECs targets, but neither had procured sufficient SRECs to meet the solar PV requirements. The Commission approved the IPA's proposed 1-year SRECs procurement for ComEd and Ameren Illinois to meet the shortfalls. That SREC procurement was held in the spring of 2015.

Ameren Illinois and ComEd will be short SRECs and DG RECs for the 2016-2017 delivery year, and MidAmerican is short RECs for overall renewable energy resource compliance, wind RECs, SRECs, and DG RECs due to not having previously participated in the IPA procurement process. ComEd is short RECs for overall renewable energy resource compliance, but procuring its required SREC volume would be sufficient to fill that gap. To achieve statutory compliance, the IPA recommends a spring 2016 procurement of RECs to meet each utility's requirements (other than to meet the Distributed Generation sub-targets, as discussed below) for the 2016-2017 delivery year. The quantities to be procured will be based upon the "Remaining Targets" as calculated from the updated March 2016 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 2016 load forecasts be needed and not be reached, the quantities of RECs to be procured for the 2016-2017 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. To the extent practicable, the structure, process and contracts for the procurement will be based upon those used for the SREC procurement conducted by the IPA in 2015.

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 utilities total RECs target. Depending on the results of the planned fall 2015 DG procurement, the IPA proposes to schedule at least one DG procurement in 2016 to meet the utilities' remaining 2016-2017 delivery year DG REC targets. Details related to the structure of this procurement are discussed in Section 8.4.

Under the law, the procurement of DG resources to meet those requirements will require contracts of at least 5 years.[245] Because of continued volatility in the available Renewable Resources Budget present due to customer switching manifesting itself in the potential curtailment of the existing Ameren Illinois and ComEd LTPPAs from 2010, new multi-year contracts were entered into using funds collected from eligible retail customers carry a significant risk of future curtailments (and the resolution of competing curtailment provisions between distinct sets of long-term contracts). As a result, the IPA does not recommend use of the Renewable Resources Budget for Ameren Illinois or ComEd for contracts more than 1 year in length or extending beyond the 2016-2017 delivery year. 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

[245] 20 ILCS 3855/1-75(c)(1)

resources in Illinois. Absent legislative changes to the IPA Act and the PUA, this is the limit to what the IPA can propose for use of the Renewable Resources Budget

Because MidAmerican's service territory does not feature the same load volume volatility created by customer switching, and because MidAmerican is not a party to long-term contracts for renewable energy resources, the risk of needing to curtail contracts longer than 1 year appears to be very small for MidAmerican. As a result, the IPA believes that the use of the Renewable Resources Budget would be appropriate for contracts with MidAmerican extending beyond the delivery year.

The IPA notes that Section 1-56(i) of the IPA Act required the development of a supplemental photovoltaic ("SPV") procurement plan for the procurement of RECs from photovoltaic systems. The IPA's initial SPV procurement was held in June 2015 with two additional SPV procurements planned for November 2015 and March 2016. As these RECs are purchased by the Agency out of the Renewable Energy Resources Fund and not by the utilities, the SRECs procured under the SPV plan do not count towards the utilities' DG RECs or SRECs targets.

8.1 Current Utility Renewable Resource Supply and Procurement

8.1.1 Ameren Illinois

As shown in Table 8-1, Ameren Illinois' current renewable resource contracts will cover its total renewables targets for the 2016-2017 delivery year.[246] Assuming that no additional purchases of renewable energy resources are made, Ameren Illinois is projected to fall short of meeting its RPS requirements in the 2017-2018 delivery year by 6%. In the 2018-2019, 2019-2020 and 2020-2021 delivery years, the shortfall for total renewables is projected to reach 41%, 47% and 51%, respectively.

Table 8-1 also shows the targets and purchasing requirements for Ameren Illinois to meet the goals set by the Illinois Power Agency Act for wind, photovoltaics, and distributed generation based on the currently established fractions of the total renewables requirement.[247] Ameren Illinois is projected to meet its wind generation goals for the 2016-2017 and the 2017-2018 delivery years. Assuming that no additional purchases are made, Ameren Illinois is projected to fall short of the wind goal by 22%, 29% and 35% in the 2018-2019, 2019-2020, and 2020-2021 delivery years, respectively. Assuming that no additional purchases of PV and DG are made, Ameren Illinois is projected to fall short of the photovoltaic and distributed generation goals in each delivery year.

Additionally, Ameren Illinois is projected to have Renewable Resources Budget funds[248] with which to purchase renewables (Table 8-4).[249]

[246] This Table does not include the results of the upcoming DG procurement; as that procurement will feature 5-year contracts, it may impact these volumes.
[247] 20 ILCS 3855/1-75(c)(1).
[248] Available renewable resources budget funds for the upcoming year are a result of the higher load forecast relative to that utilized in last year's procurement plan. The RPS budget is a function of, among other things, forecasted eligible retail load. Relative to last year, forecasted eligible retail load is significantly higher as of this procurement plan due to the recent observation of communities opting to suspend their municipal aggregation programs and take supply from Ameren Illinois.
[249] In its comments on the Agency's draft 2015 Plan, Ameren asked the IPA to affirmatively state that Ameren Illinois' excess wind RECs not be sold back to the market, and instead recommended that these RECs be retired consistent with contractual procedures. The IPA has no plan or intention to sell the RECs from any existing utility contract back to the market, and thus has asked for no authority to this effect in its 2016 Procurement Plan.

Table 8-1: Ameren Illinois Existing RPS Contracts vs. RPS Requirements[250]

Delivery Year		Total Renewables	Wind	Photo-voltaics	Distributed Generation
2016-2017	Target (MWh)	776,681	582,510	46,601	7.767
	Purchased MWh	1,029,245	976,851	12,394	0
	Remaining Target (MWh)	--	--	34,207	7,767
2017-2018	Target (MWh)	907,169	680,377	54,430	9,072
	Purchased MWh	854,396	848,338	6,058	0
	Remaining Target (MWh)	52,773	--	48,372	9,072
2018-2019	Target (MWh)	1,013,368	760,026	60,802	10,134
	Purchased MWh	600,000	596,571	3,429	0
	Remaining Target (MWh)	413,368	163,455	57,373	10,134
2019-2020	Target (MWh)	1,122,680	842,010	67,361	11,227
	Purchased MWh	600,000	596,571	3,429	0
	Remaining Target (MWh)	522,680	245,439	63,932	11,227
2020-2021	Target (MWh)	1,233,082	924,812	73,985	12,331
	Purchased MWh	600,000	596,571	3,429	0
	Remaining Target (MWh)	633,082	328,241	70,556	12,331

8.1.1.1 Ameren Illinois SREC Procurement for 2015-16 Delivery Year

On April 16, 2015, the IPA held an SREC procurement pursuant to the procurement plan approved by the Commission in Docket No. 14-0588. A total of 30,212 SRECs were acquired to meet Ameren Illinois' procurement target for the 2015-16 delivery year. No SRECs were procured for subsequent delivery years. A procurement event for up to 6,518 DG RECs/year is planned for the fall of 2015; pursuant to the provisions of Section 1-75(c) of the IPA Act, this procurement will feature five-year contracts (extending into future delivery years).

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.[251] ComEd's forecast indicates that for the 2016-2017 delivery year total renewables are 67,960 RECs short of the target while enough renewables have been procured to meet its wind targets. In subsequent delivery years, ComEd is forecasted to fall short of its total renewables target by 35% in 2017-2018, 56% in 2018-2019, 63% in 2019-2020, and 67% in 2020-2021. ComEd is also forecasted to fall short of the photovoltaic and distributed generation targets in each of the five delivery years considered in this Plan and to fall short of the wind target in the 2017-2018 delivery year and beyond.

As with Ameren Illinois, ComEd is also projected to have Renewable Resources Budget funds[252] with which to purchase renewables (Table 8-5).

[250] Volumes are based on the July 2015 expected load forecast. The March 2016 load forecast will update the 2016-2017 volumes and the quantity of DG RECs purchased in the fall 2015 procurement, and future years' actual procurement targets will be based off of those future years' load forecasts. .
[251] This Table does not include the results of the upcoming DG procurement which will feature 5-year contracts and thus impact these volumes
[252]See prior footnote re: load migration.

Table 8-2: ComEd Existing RPS Contracts vs. RPS Requirements[253]

Delivery Year		Total Renewables	Wind[254]	Photo-voltaics[255]	Distributed Generation[256]
2016-2017	Target (MWh)	1,629,357	1,222,018	97,761	16,294
	Purchased MWh	1,561,397	1,340,016	27,895	0
	Remaining Target (MWh)	67,960	--	69,866	16,294
2017-2018	Target (MWh)	2,360,934	1,770,700	141,656	23,609
	Purchased MWh	1,533,198	1,233,838	27,887	0
	Remaining Target (MWh)	827,736	536,862	113,769	23,609
2018-2019	Target (MWh)	2,878,296	2,158,722	172,698	28,783
	Purchased MWh	1,261,725	1,233,838	27,887	0
	Remaining Target (MWh)	1,616,571	924,884	144,811	28,783
2019-2020	Target (MWh)	3,444,117	2,583,087	206,647	34,441
	Purchased MWh	1,261,725	1,233,838	27,887	0
	Remaining Target (MWh)	2,182,392	1,349,249	178,760	34,441
2020-2021	Target (MWh)	3,789,473	2,842,105	227,368	37,895
	Purchased MWh	1,261,725	1,233,838	27,887	0
	Remaining Target (MWh)	2,527,748	1,608,267	199,481	37,895

8.1.2.1 ComEd SREC Procurement for 2015-16 Delivery Year

On April 16, 2015, the IPA held an SREC procurement pursuant to the procurement plan approved by the Commission in Docket No. 14-0588. A total of 49,700 SRECs were acquired to meet ComEd's procurement target for the 2015-16 delivery year. No SRECs were procured for subsequent delivery years. A procurement event for up to 13,194 DG RECs/year is planned for the fall of 2015; pursuant to the provisions of Section 1-75(c) of the IPA Act, this procurement will feature five-year contracts (extending into future delivery years).

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. MidAmerican does not currently have any existing purchased RECs to meet these targets. If the IPA is directed to procure RECs based on only MidAmerican's incremental load in Illinois, then the REC quantities required would be approximately 14% of the quantities shown in the table

[253] Volumes are based on the July 2015 expected load forecast. The March 2016 load forecast will update the 2016-2017 volumes and the quantity of DG RECs purchased in the fall 2015 procurement, and future years' actual procurement targets will be based off of those future years' load forecasts.
[254] Wind RPS requirement is 75% of the annual RPS requirement. See 20 ILCS 3855/1-75(c)(1).
[255] PV RPS requirement is 6% of the annual RPS requirement. See 20 ILCS 3855/1-75(c)(1).
[256] Distributed Generation RPS requirement is 1% of the annual RPS requirement. See 20 ILCS 3855/1-75(c)(1).

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

Delivery Year		Total Renewables	Wind[257]	Photo-voltaics[258]	Distributed Generation[259]
2016-2017	Target (MWh)	220,418	165,313	13,225	2,204
	Purchased MWh	0	0	0	0
	Remaining Target (MWh)	220,418	165,313	13,225	2,204
2017-2018	Target (MWh)	258,864	194,148	15,532	2,589
	Purchased MWh	0	0	0	0
	Remaining Target (MWh)	258,864	194,148	15,532	2,589
2018-2019	Target (MWh)	289,334	217,000	17,360	2,893
	Purchased MWh	0	0	0	0
	Remaining Target (MWh)	289,334	217,000	17,360	2,893
2019-2020	Target (MWh)	320,477	240,358	19,229	3,205
	Purchased MWh	0	0	0	0
	Remaining Target (MWh)	320,477	240,358	19,229	3,205
2020-2021	Target (MWh)	351,859	263,894	21,112	3,519
	Purchased MWh	0	0	0	0
	Remaining Target (MWh)	351,859	263,894	21,112	3,519

8.2 Available Renewable Resources Budget and LTPPA Curtailment

In 2010, pursuant to an IPA procurement, ComEd and Ameren entered into long-term (20-year) contracts for renewable energy resources ("LTPPAs") from a series of wind and photovoltaic 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 risks being triggered by customers switching to alternative suppliers and consequently load shifting away from the utilities, thus reducing the available budget.

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. For the 2013-2014 and 2014-15 delivery years, in an effort to keep the cost of renewable energy resources below the statutory rate impact cap, the Commission pre-approved the curtailment of the 2010 LTPPAs based on the information contained in that subsequent March's updated load forecasts. Curtailment has been required of ComEd's LTPPAs, but has not yet been required for the Ameren Illinois contracts. Curtailments were not required in the 2015-2016 delivery year and, based on the load forecasts supplied by the utilities, are not currently anticipated over the five-year forecast horizon of the 2016 Procurement Plan.

For the 2016-2017 delivery year, the Ameren Illinois and ComEd load forecasts have grown significantly based largely on a significant number of municipalities suspending their municipal aggregation programs and returning to utility supplied service. Because the delivery year Renewable Resource Budget is a function of the amount of eligible utility load, which has increased relative to last year's load forecasts, it is forecasted that the delivery year Renewable Resource Budgets will 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

[257] Wind RPS requirement is 75% of the annual RPS requirement. See 20 ILCS 3855/1-75(c)(1).
[258] PV RPS requirement is 6% of the annual RPS requirement. See 20 ILCS 3855/1-75(c)(1).
[259] Distributed Generation RPS requirement is 1% of the annual RPS requirement. See 20 ILCS 3855/1-75(c)(1).

forecasted to have sufficient funds available in each of the five delivery years covered by this plan. MidAmerican does not hold any LTPPAs.

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

Delivery Year	Contractual REC Cost ($)	Delivery Year RPS Budget ($)	Available RPS Funds ($)	LTPPA Quantity Reduction (%)
2016-2017	10,403,861	12,617,481	2,213,620	0.0%
2017-2018	9,412,155	12,668,038	3,255,883	0.0%
2018-2019	8,000,000	12,721,183	4,721,183	0.0%
2019-2020	7,999,000	12,768,585	4,769,585	0.0%
2020-2021	7,753,000	12,768,585	5,015,585	0.0%

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

Delivery Year	Contractual REC Cost ($)	Delivery Year RPS Budget ($)	Available RPS Funds ($)	LTPPA Quantity Reduction (%)
2016-2017	23,502,192	37,550,843	14,048,651	0.0%
2017-2018	23,803,641	40,720,222	16,916,581	0.0%
2018-2019	23,438,590	40,963,118	17,524,528	0.0%
2019-2020	23,566,909	41,254,513	17,687,604	0.0%
2020-2021	23,178,932	41,280,076	18,101,144	0.0%

The contracted REC costs for the 2016-17 delivery year for Ameren Illinois and ComEd are respectively 82% and 63% of the current estimates of their respective 2016-17 RPS budget caps. Those budgets depend directly on eligible retail load, so it appears that as long as ComEd's March 2016 forecast for 2016-2017 load is close to 63% of its July 2015 forecast value, and as long as Ameren Illinois' is March 2016 forecast for 2016-2017 load is in turn close to 82% of its July 2015 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 forecasts that the Renewable Resources Budget would be exceeded and a partial curtailment of LTPPAs would be needed.

While it appears highly unlikely that curtailment of the LTPPAs would be required in the 2016-2017 delivery year, the IPA still recommends that a final determination be based upon the March 2016 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).[260] While it is again highly unlikely that curtailments will be required, as 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.

Table 8-6shows the budget available for MidAmerican. If the IPA is directed to procure RECs based on only MidAmerican's incremental load in Illinois, then the available budget would be approximately 14% of the quantities shown in the table

[260] In its Order on Rehearing, the Commission requested that, "what allocation method should be used will be reviewed again and determined in the IPA Procurement Plan case for the 2015-2016 year." (Docket No. 13-0546, Order on Rehearing at 56) due to the low probability of needing to curtail the LTPPA contracts in the 2015-16 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.

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

Delivery Year	Delivery Year RPS Budget ($)	Available RPS Funds ($)
2016-2017	2,477,311	2,477,311
2017-2018	2,486,717	2,486,717
2018-2019	2,496,201	2,496,201
2019-2020	2,507,235	2,507,235
2020-2021	2,518,768	2,518,768

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.[261] 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.[262] As required by the IPA Act, each utility has disclosed the amount of hourly customer ACP funds being held as of May 31, 2015: for Ameren Illinois, the balance is $10,040,276; for ComEd, the balance is $19,039,957.

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."[263] Starting with the 2013-2014 delivery year, the Commission approved the use of hourly ACP funds to purchase RECs from any curtailed LTPPAs, and the IPA recommends a continuation of that policy.

As previously discussed, the utilities have a current shortfall in meeting their statutory DG targets (although the extent of that shortfall will not be known until the completion of the Fall 2015 DG procurement). It therefore appears that utilizing the already collected, and otherwise unspent, hourly ACP funds to allow Ameren Illinois and ComEd to meet their DG targets would be appropriate to further an aspect of the utilities' RPS obligations. Additionally, as contracts for DG resources must be "no less than 5 years" in length,[264] 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, as detailed above) while ensuring that there are no impacts on customer rates. 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 is the first of its kind conducted by the IPA.

8.4 Distributed Generation Procurement

As part of the development of the 2015 Plan, after analysis and review of comments from stakeholders and additional consideration (including coordination, where possible, with the SPV procurement plan), the IPA settled on a distributed generation procurement model for the fall 2015 procurement. This model was based on the Agency's traditional procurement process involving the block procurement of renewable energy credits with competitive bids selected on the basis of price. As the Agency is proposing a distributed generation procurement to meet statutory DG targets, and not simply a solar photovoltaic REC procurement,

[261] See 20 ILCS 3855/1-75(c)(5).
[262] See id.
[263] Id.
[264] 20 ILCS 3855/1-75(c)(1).

the Agency also believes that this model left it best able to accommodate RECs from generating technologies beyond solar photovoltaics.

The IPA is proposing the model as implemented for the 2015 procurement as the starting point for a 2016 procurement of DG RECs beginning in the 2016-2017 delivery year. While the final results of this procurement event will still not be known by the filing of this Plan on September 28, 2015, more information will be available on the response to the procurement event. As a result, the IPA may make additional changes to this model in its September filed Plan, and specifically seeks comments on this DG procurement proposal from parties engaged in the development of and participation in that procurement process.

Unlike with the IPA's SPV procurement under Section 1-56(i) of the IPA Act, nothing in the law governing this DG procurement distinguishes between "new" or "existing" systems. As a result, the Agency's sole requirement regarding the system completion date is that all participating DG systems must successfully begin delivery of RECs generated in the 2016-2017 delivery year. Contracts will be for the five delivery years starting with 2016-2017 delivery year.

The IPA recognizes that given the limited amount of distributed generation currently in Illinois, this approach's success hinges on the ability of the Illinois DG market both to self-organize and to grow. Therefore the Agency will allow bids to contain DG systems of all qualifying sizes and resource types. Systems must be no larger than 2,000 kW. The technology types eligible to participate are defined by the IPA Act and include DG "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."[265] Benchmarks used by the Procurement Administrator to evaluate bids may depend on system size and/or technology. Bids that meet or beat the benchmarks will be evaluated first on the basis of price, and then on the basis of achieving 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, while maintaining winning bid sizes at a one megawatt threshold.

The IPA's planned DG renewable resource procurement will use hourly ACP funds for Ameren Illinois and ComEd, and use the Renewable Resources Budget for MidAmerican. Only hourly ACP funds that have been collected as of May 30, 2016 and not allocated to the purchase of either DG RECs from the five-year 2015 DG procurement contracts or curtailed RECs for the 2016-2017 delivery year may be used. 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, a municipal utility in Illinois, or a rural electric cooperative in Illinois. DG systems need not be in the service territory of the utility purchasing the RECs.

8.4.1 Procurement Process

The Agency's approach will be to procure DG RECs through a single procurement event in a competitive bid process in the Fall of 2016 with two categories of systems participating. The first category is for systems under 25 kW, the second for systems between 25 kW and 2 MW.

Bids must be at least one megawatt in size, but may feature a number of DG systems of all qualifying sizes and resource types. The bidder must identify the specific system(s) that will provide the RECs; "speculative bidding" of RECs from systems not specifically identified will not be permitted. Evidence regarding the systems may include, but is not limited to, letters of intent, signed contracts, interconnection or net metering applications, local permits, etc.

[265] 20 ILCS 3855/1-10.

Section 1-75(c)(1) of the IPA Act requires that aggregators "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 offered at a single blended price per REC. Subsequent blocks of DG systems must be bid at higher prices and must be at least 100 kW. Bidders may not designate different REC prices for the RECs generated from a single distributed generation system or for RECs associated with a given block. While block prices may differ, each bidder's resulting REC contract with the purchasing utility will be at a single blended price, encompassing all successful bids which have been assigned to that utility. A pre-determined capacity factor for each eligible technology will be used to calculate an annual number of RECs for each block to be delivered in each year of the contract except the first. The bid for a block may include a different number of RECs for the first year of the contract to the extent that some of the systems included in the block are not yet in operation. For the 2016-2017 delivery year RECs from any month in the delivery year will be eligible.

As required by law, the Agency must endeavor to ensure that, to the extent available, half of the total DG RECs procured by the Agency are from "devices of less than 25 kilowatts in nameplate capacity." Section 16-111.5(e) of the PUA requires that the Agency's procurement process be conducted through selecting competing bids "solely on the basis of price." The IPA believes these requirements can be properly balanced by procuring on the basis of price within each category (<25kW, and 25kW to 2 MW) while ensuring that the winning bid size remains at least one megawatt. If the target is met under the budget and one category is less than 50% of the target, then the next most competitive bid in that category would be selected and would replace DG RECs from a system in the other category (to the extent such a bid is available). This means that, for example, a sub-25kW system can be selected ahead of an above-25kW system with a lower price, but only if that selection is required to reach the target 50% of DG RECs from sub-25kW systems. The marginal bidder in the evaluation of bids could receive a contract that includes a portion of RECs from a particular system and the bidder will have the option of whether or not to accept the contract. As in other procurements conducted by the IPA, all winning bids must also be below "benchmarks" developed "for each product procured."

While each of the utilities has separate compliance targets and budgets, winning bids will be assigned to the utilities using as a guide each utility's pro-rata share of total RECs and minimizing the number of winning bidders that have contracts with more than one utility.[266] Each system covered by a contract awarded in this procurement must begin accumulating metered deliveries of renewable energy prior to the end of the 2016-2017 delivery year (May 31, 2017). Suppliers will be required to demonstrate that each system has generated electricity that was tracked by GATS or M-RETS by May 31, 2017. Should a system not comply with this requirement, the bidder's contract volume will be reduced accordingly by the amount allocated to that system.

Within 2 days after a procurement event featuring "sealed, binding commitment bidding" with bids selected "on the basis of price," reports on the procurement event are to be submitted by the procurement administrator and the Commission's procurement monitor to the Commission for review. These reports are to contain bidding results, a recommendation for the rejection or acceptance of bids, and the assignment of winning bids to each utility. The Commission will then issue a decision on whether to accept or reject the procurement results within 2 days after receiving the reports.

Within 3 days after the Commission's decision, "the utility shall enter into binding contractual arrangements with the winning suppliers using the standard form contracts."

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[266] 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 evenly be divided due to the size of the bids.

8.4.2 Key Contract Terms

Contracts under the DG procurements are between winning bidders and Ameren Illinois, ComEd, or MidAmerican; the IPA is not a contract party as it is for the procurements of solar photovoltaic RECs conducted pursuant to the Supplemental Photovoltaic Procurement Plan. Contracts will provide payment for RECs generated over a five year delivery years starting with the delivery year that commences on June 1, 2016. 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 with consent from the utility. Such consent will be automatic if the ownership of the system changes, if the assignment is to an affiliate of the counterparty, or is for financing purposes. The counterparty will be required to effect such assignment or transfer in the event of bankruptcy or dissolution.

8.4.3 Credit Requirements and Bidder/Supplier Fees

The IPA is required to recover the cost of conducting this procurement through bidder fees[267] and to develop "standard credit terms and instruments."[268] For this procurement, those are as follows:

- All bidders will pay a $500 non-refundable bid participation fee. This fee is non-refundable and will be assessed evenly across all bidders.
- Bidders will provide a deposit (in the form of a pre-bid letter of credit to the IPA) of $8/REC as part of the bidder registration process. Bidders whose bids are not selected will have their pre-bid letter of credit returned. For a bidder who only is successful for a portion of their bids, the return will be prorated based upon their winning bids.
- Winning bidders will be assessed a Supplier Fee that reflects the balance of the cost of conducting the procurement less the total of the bid participation fees. 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 days after the approval of the procurement results by the Commission to pay the Supplier Fee due to the IPA (and upon doing so will have their deposit – the pre-bid letter of credit - released).
- All winning bidders will also have seven days after the approval of the procurement results by the Commission to provide a post-bid letter of credit to the IPA in the amount of 10% of the total value of the contract(s) awarded.
- The IPA will return an adjusted letter of credit back to the winning bidder upon the bidder demonstrating to the IPA that each specific project has begun delivery of RECs from the 2016-2017 delivery year to the applicable utility.
- Any system that is not successfully developed will forfeit its deposit for those RECs.

In addition to the credit requirements described in this session, the REC delivery contract with the utility may also include an ongoing performance assurance credit requirement that begins with the start of REC delivery. REC delivery contract terms and conditions will be developed consistent with the contract development process and requirements set forth in Section 16-111.5(e)(2) of the PUA.

8.4.4 Aggregators

Unlike with the IPA's Supplemental Photovoltaic Procurement Plan developed pursuant to Section 1-56(i) of the IPA Act, which does not define aggregator size, Section 1-75(c)(1) requires that aggregators "aggregate

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[267] 20 ILCS 3855/1-75(h).
[268] 220 ILCS 5/16-111.5(e)(2).

distributed renewable energy into groups of no less than one megawatt in installed capacity." The IPA will allow for "self-aggregation" from system owners, so long as those bids are at least one megawatt. The bidder will serve 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 would both need to 1) have RECs available for procurement (i.e., not already under contract) and be willing to transfer available RECs;[269] and 2) have the knowledge and understanding necessary to participate through an aggregator in an IPA procurement event. In its 2015 Plan, in an attempt to allow the market sufficient time to organize, the IPA scheduled its DG procurement for the Fall of 2015. While this later procurement date risked more time spent out of compliance with statutory DG procurement goals during the 2015-16 delivery year, the IPA felt it necessary to allow aggregators and other interested parties sufficient time to organize systems and bids for its first DG procurement.

Keeping with that schedule, and in recognition of the proposed and scheduled SREC procurements due to take place under the SPV and the 2016 Procurement Plan during the Spring of 2016, the IPA again proposes that its DG procurement be held later in the year, in the Fall of 2016. The IPA will allow for the contract delivery of all RECs generated during the 2016-17 delivery year from winning bidders (and not only those RECs generated after the execution of contracts).

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

The RERF balance as of April 1, 2015 equals $30,550,341.21, the total amount received in the IPA's RERF attributable to ARES ACP payments less the cost of RECs purchased per the IPA's offer to use RERF funds to purchase curtailed RECs from the 2010 LTPPAs that were not purchased by ComEd using hourly ACP funds, and a $98 million transfer to the Illinois General Revenue Fund pursuant to Public Act 99-0002. Prior to 2015 the ICC has held that it did not have jurisdiction over the RERF, and as a result the IPA did not seek approval for procurement using the RERF in previous plan years.[270]

Section 1-56(i) of the IPA Act required the IPA to develop a supplemental photovoltaic ("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 first procurement event under that plan was held in June 2015 and successfully allocated the full $5 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.

[269] 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.

[270] Docket No. 12-0544, Final Order dated December 19, 2012 at 112-114.

9 Procurement Process Design

The procedural requirements for the procurement process are detailed in the Illinois Public Utilities Act at Section 16-111.5.[271] 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[272], 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.

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

[272] 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.

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

(4) Request for proposals competitive procurement process.

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

(5) A plan for implementing contingencies

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

9.1 Contract Forms

Of these five process components, the IPA has implemented changes related to item (2): development of standard contract forms and credit terms and instruments in order to achieve process efficiency improvements designed to lower the overall costs to ratepayers. 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 and 2015 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 2016 Procurement Plan would be the tenth iteration of IPA-run procurement events, when including the April 2015 procurement event, the Supplemental Photovoltaic Procurement, and the planned September 2015 procurement event. 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 and 2015 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.

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 2015 procurement events be the starting point for the contracts used in the energy, capacity and SREC 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.

9.2 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."[273] 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.[274]

The IPA has 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 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

[273] 20 ILCS 3855/1-75(h).
[274] 83 Ill. Admin. Code. 1200.110, 1200.220.

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 and 2015 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 2014 and 2015 procurement events be continued to support the procurement events recommended in this Plan. That approach is 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 2014 and 2015 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.

9.3 Second Procurement Event

The IPA recommends that procurement events be held in the spring and fall of 2016 for purchase of energy blocks, capacity and RECs under the 2016 Procurement Plan. All of 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
- 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, AIC and ComEd as well as a portion of the AIC capacity requirements and all of MidAmerican forecast capacity shortfall for the following five-planning years.

9.4 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 22, 2015 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 2014 and the spring of 2015. The summer 2014 event involved the repurchase of RECs following ComEd's partial curtailment of REC purchases under the terms of the 20-year renewable energy contracts that were executed in December 2010. A total of 85,891 RECs were repurchased for ComEd in the summer event, which took place following the Commission's June 17, 2014 Order on Rehearing in Docket No. 13-0546. The fall 2014 procurement involved the procurement of standard energy products to meet the requirements of ComEd's and AIC's eligible customers for November 2014 through May 2015. The spring 2015 procurement events included the purchase of a portion of the utilities' energy requirements to meet eligible customers' needs for the 2015-2016, 2016-2017 and 2017-2018 delivery years. The spring 2015 procurement events also included the purchase of SRECs for ComEd and AIC.

Initial comments, which were due to the Commission by June 29, 2015, were received from Boston Pacific Company, Inc. ("Boston Pacific").[275] Boston Pacific's comments focused on: a summary of the results of these procurement events; the effectiveness of holding spring and fall procurement events; observations regarding the locational preference and pre-bid security options for the SREC procurements; and, the potential impact that the introduction of a "Low Carbon Portfolio Standard" to support existing nuclear generation in the state would have on the IPA's procurement process. Boston Pacific suggested that, for the SREC procurements in particular, to meet pre-bid security requirements cash should be accepted in lieu of a pre-bid letter of credit which could alleviate the administrative problems that some small bidders can encounter in securing a letter of credit. While this may help some of the potential bidders, posting cash in lieu of a letter of credit does not easily fit the current procurement administrative process and the IPA does not recommend making this change. A reply comment was received on July 27, 2015 from Exelon Generation. It reiterated their past position in favor of a Full Requirements procurement approach.

The comments received in the informal hearings are available on the Commission's web site.

[275] Boston Pacific served as the Commission's procurement monitor for all of these procurement events.

Appendices

Appendices are available separately at:

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

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