2014

ILLINOIS
POWER AGENCY

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[ELECTRICITY PROCUREMENT PLAN]

Prepared in accordance with the Illinois Power Agency and Illinois Public Utilities Acts

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Illinois Power Agency

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1 Executive Summary

This is the sixth electricity and renewable resource procurement plan (the "Plan", "2014 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"). Section 2.1 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") and Commonwealth Edison ("ComEd") as defined in Section 16-111.5(a) of the PUA, who generally are residential and small commercial fixed price customers who have not chosen service from an alternate supplier. The Plan considers a 5-year planning horizon that begins with the 2014-2015 delivery year and lasts through the 2018-2019 delivery year.

The fifth plan developed by the IPA, and approved by the Commission in ICC Docket No. 12-0544, was the first plan that recommended no procurement of electricity or renewable resources for the utilities. It was also the first plan that included incremental energy efficiency programs as mandated by Section 16-111.5B of the PUA. The decision not to conduct any procurement of electricity in calendar year 2013 was a reflection of the monumental changes in the Illinois electricity markets brought about by the rapid increase in customer switching due to retail competition and municipal aggregation.

Although switching led the portfolio considered in last year's plan to be long and thus without procurement needs, this plan recommends a return to electricity procurements to address supply shortfalls and switching risk (Chapter 7). This conclusion is based on the IPA's analysis of the load forecast scenarios (Chapter 3), the expiration of existing supply contracts (Chapter 4), and the IPA's analysis of the risks associated with serving electric load and the various factors of power procurement (Chapter 6). The Plan continues to recommend no procurement of renewable resources for the utilities because current targets are being exceeded and the statutory rate caps preclude any additional procurement and the Plan also continues to recommend no sale of renewable resources for existing quantities in excess of targets (Chapter 8) The accelerated switching of load to competitive supply associated with governmental aggregation (which led to no procurement in 2013) is unlikely to continue at the same accelerated pace as has been seen since roughly 2011. Market saturation coupled with decreased headroom for competitive suppliers will drive any slowing or reversal of municipal aggregation gains. Most, though not all, of the large blocks of load that could switch have now done so and any likely additional load switching will come from ongoing retail marketing. The available headroom has diminished as a consequence of the utilities' current supply portfolio's lower price relative to market; it is now significantly closer to market price. As a consequence of these factors, the supply strategy presented in this plan takes the cautious view that expiring municipal aggregation contracts provide switching risk that the IPA must account for when considering what procurements to propose for eligible retail customers. To mitigate that risk, the IPA proposes a second procurement event to be held in September 2014 unless ComEd's load drops significantly below current projections and other factors determine that a second procurement is not cost-effective. In the event a second procurement is held, the parties shall rely on the same contracts and letter of credit forms used for the initial procurement in April 2014.

1.1 Power Procurement Plan

This Procurement Plan proposes to continue using the 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 investigated alternative strategies such as full requirement contracts or use of options, the IPA believes the continuation of the IPA's past strategy at this time to be the most prudent and the most likely to produce 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]

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, the Plan makes several recommendations for procurements for delivery year 2014-2015. The Plan recommends decreasing the size of procurement blocks from 50MW to 25MW. The hedging strategy is revised to bifurcate the first delivery year into two periods with different hedging levels. The summer would be "fully hedged" at the time of the April procurement and the balance of the year 75% hedged. The IPA recommends the Commission pre-approve a supplemental September procurement, which would bring the hedging level for the rest of the first delivery year to the "fully hedged" level. Approval would be based on factors intended to ensure that the benefits of the September procurement outweigh the costs of running the procurement. The strategy for years two (delivery year 2015-2016) and three (delivery year 2016-2017) reflects lower forward hedging strategies when compared to prior Plans. The proposed overall strategy 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.

The IPA continues to recommend that capacity, ancillary services, load balancing services, and transmission services be purchased, as they are now, by Ameren from the MISO marketplace and by ComEd from PJM.

1.2 Renewable Energy Resources

The load forecasts supplied by the utilities on July 15, 2013 indicate that existing renewable energy resources under contract exceed the Renewable Portfolio Standard obligations for eligible retail customers. Separately, the statutorily mandated rate caps also lead the IPA to recommend that the Commission approve a curtailment of the long-term power purchase agreements that were entered into as part of the 2010 procurement plan based on utility load forecast updates in Spring 2014. This is essentially the same as was adopted in last year's plan. To mitigate the impact of those curtailments the IPA also recommends the use of Alternative Compliance Payments collected from customers on hourly pricing to purchase some or all of the curtailed Renewable Energy Credits ("RECs"). While not subject to ICC jurisdiction, the IPA will also plan to use funds from the RERF to purchase any remaining curtailed RECs.

The following tables summarize the IPA's proposed hedging strategy and the IPA's proposed 2014 procurements:

Table 1-1 Summary of 2014 Illinois Agency Hedging Strategy

Mid-April 2014 Procurement			Mid-Sept 2014 Procurement
June 2014-May 2015 (Upcoming Delivery Year)	**Upcoming Delivery Year+1**	**Upcoming Delivery Year+2**	**November 2014-May 2015**
106% (June-Oct.) 75% (Nov.-May)	50%	25%	100%

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

Table 1-2 Summary of 2014 Illinois Power Agency Procurement Plan Recommendations based on July 15, 2013 Utility Load Forecasts:

	Delivery Year	Energy	Capacity	Renewable Resources	Ancillary Services
AMEREN	2014-15	Up to 175MW forecasted requirement (April Procurement)	Direct purchase from MISO capacity market	No RPS procurement: target exceeded (except solar and DG), budget cap exceeded	Will be purchased from MISO
	2015-16	Up to 150MW forecasted requirement (April Procurement)	Direct purchase from MISO capacity market	No RPS procurement: target exceeded (except for solar and DG) and budget cap exceeded	Will be purchased from MISO
	2016-17	Up to 150MW forecasted requirement (April Procurement)	Direct purchase from MISO capacity market	No RPS procurement: target exceeded (except for solar and DG) and budget cap exceeded	Will be purchased from MISO
	2017-18	No energy procurement required	Direct purchase from MISO capacity market	No RPS procurement: target exceeded (except for solar and DG) and budget cap exceeded	Will be purchased from MISO
	2018-19	No energy procurement required	Direct purchase from MISO capacity market	Shortage of 10GWh but budget cap exceeded: no RPS procurement	Will be purchased from MISO
	Delivery Year	**Energy**	**Capacity**	**Renewable Resources**	**Ancillary Services**
COMED	2014-15	Up to 1,175MW forecasted requirement (April Procurement) Up to 350MW additional forecasted requirement (September Procurement)	Direct purchase from PJM capacity market	Shortage of 116GWh but budget cap exceeded: no RPS procurement	Will be purchased from PJM
	2015-16	Up to 375MW forecasted requirement (April Procurement)	Direct purchase from PJM capacity market	No RPS procurement: target met and budget cap exceeded.	Will be purchased from PJM
	2016-17	No energy procurement required	Direct purchase from PJM capacity market	No RPS procurement: target met and budget cap exceeded.	Will be purchased from PJM
	2017-18	No energy procurement required	Direct purchase from PJM capacity market	No RPS procurement: target met and budget cap exceeded.	Will be purchased from PJM
	2018-19	No energy procurement required	Direct purchase from PJM capacity market	Shortage of 178GWh but budget cap exceeded: no RPS procurement	Will be purchased from PJM

1.3 Incremental Energy Efficiency

This plan is the second year of 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 Test. The IPA further suggests consideration be given to issues relating to other third party programs that the utilities did not include in their savings goals but that the IPA believes should be presented by the IPA to the Commission.

Finally the IPA recommends that the Commission adopt the recommended policies laid out by the IPA in Section 7.1 to address open questions involving incremental energy efficiency procurement, including adoption of certain consensus items from recent workshops relevant to the Section 16-111.5B procurement process.

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 and Ameren as submitted in July 2013.
2. Require the utilities to provide an updated March 2014 forecast which will be pre-approved by the ICC in this docket subject to the March 2014 consensus of each utility, the IPA, ICC Staff, the Procurement Administrator(s) and the Procurement Monitor.
3. Approve two energy procurements. The first in April 2014, the second in September 2014. The September procurement will be held subject to a July 2014 forecast indicating a hedging shortfall exists for the prompt year, a determination that the estimated hedging benefit exceeds the cost of the procurement, and other conditions as specified by the Commission.
4. Require the utilities to expand the July 2014 forecast to include the November 2014 to May 2015 period. The addition of the November 2014 through May 2015 forecast will be used solely in determining the quantity of energy to be solicited, if applicable, in the September 2014 procurement event and will have no bearing on the renewable curtailment.
5. Approve continued procurement by ComEd and Ameren of capacity, network transmission service and ancillary services from their respective RTO for the 2014-2015 delivery year.
6. Approve pro-rata curtailment of ComEd and Ameren's Long-Term Power Purchase Agreements for renewable energy, subject to the updated March 2014 forecast. This forecast will form the basis for pro-rata curtailment of long term renewable contracts assuming consensus is reached among the aforementioned parties. Otherwise, the July 2013 forecast will form the basis for curtailment.
7. Approve the use of hourly ACP funds to buy curtailed RECs.
8. Approve the Section 16-111.5B incremental energy efficiency programs submitted by the utilities. The IPA also identified additional energy efficiency programs which were not included in the savings goal for the ICC to consider and approve as appropriate.
9. Approve and adopt the solutions to open Section 16-111.5B energy efficiency procurement issues recommended by the IPA, or as modified in response to stakeholder input. These recommendations include which programs the IPA must provide to the Commission, and then which programs the Commission may or should not approve.

The Illinois Power Agency respectfully submits this Procurement Plan, which the IPA believes is compliant with all applicable laws, to the Illinois Commerce Commission for review and approval.

2 Legislative/Regulatory Requirements of the Plan

This section of the 2014 Procurement Plan describes the legislative and regulatory requirements applicable to this Procurement Plan. This includes 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 customers, particularly customers in service classes that have not been declared competitive and who take service from the utility's bundled rate ("eligible retail customers"),[2] benefit from retail and wholesale competition. This objective of the Act was to improve the process to procure electricity for those customers.[3] 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."[4] The General Assembly also stated "investment in energy efficiency and demand-response measures, and to support development of clean coal technologies and renewable resources" as additional goals.[5]

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").[6] 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").[7] 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" and "Procurement Administrator."[8] The Illinois Commerce Commission ("Commission" or "ICC") is tasked with approval of the plan and monitoring of the procurement events through a Commission-hired "Procurement Monitor."[9]

2.2 Procurement Plan Development and Approval Process

Although the procurement planning process is ongoing and incorporates party input and lessons from past proceedings, the statutory timeline for this 2014 Procurement Plan began on July 15, 2013. On that date, each Illinois utility that procures electricity through the IPA submitted load forecasts. These forecasts – which form the backbone of the Procurement Plan and which are covered in Sections 3.2 and 3.3 in greater detail – cover the five-year planning period for the next procurement plan. The forecasts include hourly data representing high, low and expected scenarios for the load of the eligible retail customers.

Next, the IPA prepared a draft Procurement Plan and on August 15 made it available for public comment. The Public Utilities Act provides for a 30-day comment period starting on the day the IPA released the plan. Because the 30th day was on a Saturday, the comment period closed on Monday, September 16, 2013. During the thirty-day comment period, the IPA held one public hearing within each utility's service area for the purpose of receiving public comment on the procurement plan; those public hearings were on September 4

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[2] 220 ILCS 5/16-111.5(a).
[3] 20 ILCS 3855/1-5(2); 3855 /1-5(3); 3855/1-5(4).
[4] 20 ILCS 3855/1-5(1).
[5] 20 ILCS 3855/1-5(4).
[6] 20 ILCS 3855/1-20(a)(2), 3855/1-75(a).
[7] ICC Docket 11-0660, Final Order of December 21, 2011 at 1. Although the IPA must create a procurement plan for ComEd and Ameren, the IPA must also create a procurement plan for MidAmerican Energy Company ("MidAm") if MidAm elects to opt into the IPA procurement process. (*See* 20 ILCS 3855/1-20(a)(1).) MidAm has not made such an election at this time.
[8] 20 ILCS 3855/1-75(a)(1), 3855/1-75(a)(2).
[9] 220 ILCS 5/16-111.5(b), (c)(2).

and 10, 2013 in Chicago and Springfield, respectively. Fourteen days following the end of the 30-day review period (*i.e.*, September 30, 2013), the IPA filed this revised Procurement Plan with the Commission for approval. Objections must be filed with the Commission within five days after the filing of the Plan;[10] typically the Administrative Law Judge sets the dates for Responses and Replies to Objections by Ruling 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, which this year will be Sunday, December 29, 2013 (leading to a Monday, December 30, 2013 deadline). The current ICC calendar indicates the last scheduled meeting prior to that deadline is on Wednesday, December 18, 2013.

The Commission approves the Plan, including the load forecast used in the procurement plan, if the Commission determines that it meets the requirements of the PUA.

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.[11] 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.[12] Based on that 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,[13] 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.[14]
- 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.[15] Such standard wholesale products include, but are not limited to, monthly 5 x 16 peak period block energy, monthly off-peak wrap energy, monthly 7 x 24 energy, annual 5 x 16 energy, annual off-peak wrap energy, annual 7 x 24 energy, monthly capacity, annual capacity, peak load capacity obligations, capacity purchase plan, and ancillary services.
- Detail the proposed term structures for each wholesale product type included in the portfolio of products.[16]
- 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.[17] For those portfolio measures that are identified as having significant price risk, the Plan shall identify alternatives to those measures.

[10] 220 ILCS 5/16-111.5(d)(3).
[11] 220 ILCS 5/16-111.5(b)(1)(i)-(iv).
[12] 220 ILCS 5/16-111.5(b)(2), (b)(2)(i).
[13] 220 ILCS 5/16-111.5(b)(3).
[14] 220 ILCS 5/16-111.5(b)(i), 220 ILCS 5/16-111.5(b)(iii).
[15] 220 ILCS 5/16-111.5(b)(3)(iv).
[16] 220 ILCS 5/16-111.5(b)(3)(v).
[17] 220 ILCS 5/16-111.5(b)(3)(vi).

- 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. [18]
- 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 products."[19] Reading Subsection 16-111.5(b)(3)(vi) in conjunction with Subsection 16-111.5(e) and reviewing past IPA practice, the IPA believes that the definition of "standard product" may be broad enough to include wholesale load-following products (including full requirements or partial requirements) as long as the procurement is standardized such that bids may be judged solely on price.[20] The IPA understands that the legal question of the IPA's authority to procure full requirements products was litigated in ICC Docket No. 11-0660, but the Commission did not reach the legal issue in that docket.[21] The IPA anticipates that the question will be re-litigated in this docket to the extent that ICEA's proposal for a full requirements procurement is litigated as well.

2.5 Renewable Portfolio Standard

The General Assembly has acknowledged the importance of including cost-effective renewable resources in a diverse electricity portfolio.[22] "Renewable energy resources" is defined in the Illinois Power Agency Act, and means (1) energy and its associated renewable energy credit or (2) credits alone from qualifying sources such as wind, solar thermal energy, photovoltaic cells and panels, biodiesel, and others as identified in the IPA Act.[23] 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, 2014, at least 9% of each utility's total supply should be generated from renewable energy resources.[24] For the current (2014) 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, 3% from photovoltaics, and 0.75% from distributed renewable energy generation devices.[25] Renewable energy resources procured from distributed generation devices to meet this requirement may also count towards the required percentages for wind and solar photovoltaics.[26] In other words, if the IPA procures 0.75% distributed renewable energy that is solar-generated, that 0.75% counts against the 3% solar guideline, leaving 2.25% solar to be procured from other sources.

The IPA Act defines "cost effective" in two ways: first, for different renewable resources the Procurement Administrator creates a "market benchmark" against which all bids are measured. Second, and in addition to the market 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.[27]

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[18] 220 ILCS 5/16-111.5(b)(4).
[19] 220 ILCS 5/16-111.5(b)(3)(vi).
[20] *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"); ICC 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).
[21] *See* ICC Docket No. 11-0660, Final Order dated December 21, 2011 at 174.
[22] 20 ILCS 3855/1-5(5), 3855/1-5(6).
[23] 20 ILCS 3855/1-10.
[24] 20 ILCS 3855/1-75(c)(1).
[25] Id.
[26] 20 ILCS 3866/1-75(c)(1).
[27] 20 ILCS 3855/1-75(c)(2)(E).

These values are now fixed, and the greater of the two is 0.18054 ¢/kWh for Ameren and 0.18917 ¢/kWh for ComEd.

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.[28] If cost-effective renewable energy resources are not available in Illinois or adjoining states, the IPA must instead seek cost-effective renewable energy resources from "elsewhere."[29]

In addition to the funds available from eligible retail customers, the alternative compliance payments collected by the utility from the utility's 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."[30] In the IPA's 2013 Procurement Plan approval docket, the Commission authorized these funds 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.[31]

Also in the IPA's 2013 Procurement Plan, the Commission pre-authorized a curtailment of long-term renewable PPAs, pursuant to the language of the contract. The Commission ordered that if a March, 2013 load forecast (not yet drafted at the time of the Commission's Final Order) showed that the eligible retail customer rate cap would be exceeded under the expected load forecast, the long-term renewable PPAs would be curtailed *pro rata* in order to reduce volumes to a level that would not exceed the rate cap under the expected load forecast.[32]

2.6 Distributed Generation Resources Standard

Effective beginning in the 2013 Procurement Plan, a distributed generation resource requirement was added by the General Assembly. 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.[33]

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.[34]

To the extent available, half of the renewable energy resources procured from distributed renewable energy generation shall come from devices of less than 25kW in nameplate capacity.[35]

In the Commission proceeding to approve the 2012 Electricity Procurement Plan, the Illinois Power Agency committed to holding workshops in the spring of 2012 to assist with the development of a future distributed generation renewable resource procurement plan (at this time no such procurement is planned).[36] The IPA

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[28] 20 ILCS 3855/1-75(c)(3).
[29] *Id.*
[30] 20 ILCS 3855/1-75(c)(5).
[31] ICC Docket No. 12-0544, Final Order dated December 19, 2012 at 111; *see also id.* at 114-115 (discussing mechanics of application of hourly ACP payments to curtailed RECs).
[32] *See* ICC Docket No. 12-0544, Final Order dated December 19, 2012 at 67-69, 110.
[33] 20 ILCS 3855/1-75(c)(1).
[34] 20 ILCS 3855/1-10.
[35] Id.
[36] ICC Docket No. 11-0660, Final Order dated December 21, 2011 at 117.

discussed best practices for meeting the obligations of the distributed generation portfolio requirement with stakeholders on February 24th and April 2nd 2012. Meeting materials are available on the IPA website.[37]

Further development of a distributed generation purchase program also impacts the IPA's use of the Renewable Energy Resources Fund. Although not subject to Commission jurisdiction,[38] the Renewable Energy Resources Fund may be used to procure distributed renewable energy resources, and the IPA believes it would be desirable to have a uniform purchasing program, especially if Renewable Energy Resources Fund procurements are held "in conjunction with" eligible retail customer procurements.[39]

2.7 Energy Efficiency Resources

Section 16-111.5B of the PUA, as amended by PA 97-0824 effective July 18, 2012, outlines the requirements for the consideration of energy efficiency in the Procurement Plan. The Procurement Plan must include the impact of energy efficiency building codes or appliance standards, both current and projected, and an assessment of opportunities to expand the programs promoting energy efficiency measures that have been offered by the utilities' Commission-approved energy efficiency plans or to implement additional cost-effective energy efficiency programs or measures. 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. Both Ameren and ComEd have provided this information, which is included in the Appendices to this Procurement Plan along with their load forecast information. This information includes an analysis of new or expanded programs that demonstrates their cost-effectiveness as defined in the PUA, and information sufficient to demonstrate the impacts of the assessed incremental programs on the overall cost to the utility of providing electric service, including how the cost of procuring these measures compares over the life of the measures to the prevailing costs of comparable supply, along with estimated supply quantity reductions should the IPA recommend to include them in the proposed resource portfolio. Programs come from two sources: expansion of existing utility programs authorized by the Commission pursuant to Section 8-103 of the Public Utilities Act, or new programs bid pursuant to a request for proposals undertaken annually by the utilities.

The PUA requires the Agency to include in its Procurement Plan 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. 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. 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:

> *"Total resource cost test" or "TRC test" means a standard that is met if, for an investment in energy efficiency or demand-response measures, the benefit-cost ratio is greater than one. The benefit-cost ratio is the ratio of the net present value of the total benefits of the program to the net present value of the total costs as calculated over the lifetime of the measures. A total resource cost test compares the sum of avoided electric utility costs, representing the benefits that accrue to the system and the participant in the delivery of those efficiency measures, as well as other quantifiable societal benefits, including avoided natural gas utility costs, to the sum of all incremental costs of end-use measures that are implemented due to the program (including both utility and participant contributions), plus costs to administer, deliver, and evaluate each demand-side program, to quantify the net savings obtained by substituting the demand-side program or supply resources. In calculating avoided costs of power and energy that an electric utility would otherwise have had to acquire, reasonable estimates shall be included of financial costs likely to be imposed by future regulations and legislation on emissions of greenhouse gases.*[40]

[37] http://www2.illinois.gov/ipa/Pages/CurrentEvents.aspx.
[38] *See* ICC Docket No. 12-0544, Final Order dated December 19, 2012 at 112-113.
[39] *See* 20 ILCS 3855/1-56(c) (current law requiring purchases "in conjunction with" utility procurement).
[40] 20 ILCS 3855/1-10.

Since the 2013 Procurement Plan, the IPA has engaged in significant discussions with stakeholders, including in Commission Staff-led workshops that have taken place since the Final Order in ICC Docket No. 12-0544.[41] These workshops have resulted in several "consensus" points regarding the utility-led efficiency portfolio standard required under Section 16-111.5B of the PUA. However, the IPA notes that the workshop process, while helpful, did not result in a formal agreement and therefore may not represent the formal opinions of participating parties. Further, the parties sought to, and at times did, reach consensus based on then-current, prevailing information and policy at that time of the discussions. Parties' positions were therefore subject to change based on changes in information and policy.

A list of "consensus items" is available as part of an ICC Staff report,[42] but the IPA respectfully requests that the Commission address those consensus items below that pertain directly to the Plan: [43]

1. Both new and expanded programs may be approved for up to three-year increments.
2. DCEO may bid programs into the utility-run RFPs and should pass the TRC test as indicated in the legislation.
3. 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.
4. Utilities should provide the IPA with all bids to the RFP (on a confidential basis) so the IPA may independently evaluate the bids.
5. 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 IPA further notes that parties may advocate additional items beyond the scope of the consensus items listed in the Staff Report. In that vein, the IPA raises and addresses four additional issues specific to the Procurement Plan in Section 7.1.3:

- Feedback mechanisms between the utility potential study and programs proposed (Section 7.1.3.1);
- How to undertake expansion of Section 8-103 efficiency programs in a year where the utilities' Section 8-103 efficiency plan is up for approval (Section 7.1.3.2);
- How DCEO may or should participate in the process (Section 7.1.3.3), given the consensus that DCEO programs should be considered under Section 16-111.5B; and
- How and at what stage in the process to eliminate third-party bids that are duplicative of or in competition with utility energy efficiency programs (Section 7.1.3.4).

The IPA has provided its take on addressing these issues in the subsections cited above, and looks forward to stakeholder input on the IPA's proposed resolutions.

The IPA wishes to elaborate on one item on which consensus was not achieved in the workshop but which will be relevant in this proceeding: which programs *must* be proposed (as opposed to permissively may be proposed).[44] According to statute, the Procurement Plan "shall include . . . energy efficiency programs and measures it determines are cost-effective and the associated annual energy savings goal included in the annual solicitation process and assessment [of new and expanded plans by the utilities]."[45] Meanwhile, the Commission "shall also 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

[41] *See* ICC Docket No. 12-0544, Final Order dated December 19, 2012 at 271 (directing Staff to convene workshops and requesting the IPA and other interested parties participate).
[42] *See* http://www.icc.illinois.gov/downloads/public/ICC Staff Report Summary of Section 16-111.5B EE Workshops 2013-08-02.pdf.
[43] Several additional consensus items touch on items relevant to execution of the 16-111.5B-approved programs, highlighted by evaluation of the programs, but those items are not directly relevant to approval of the programs in this proceeding.
[44] The IPA views the issues in Section 7.1.3.4 as a subset of this more general issue.
[45] 220 ILCS 5/16-111.5B(a)(4).

for all achievable cost-effective savings, to the extent practicable, and otherwise satisfy the requirements of Section 8-103 of this Act."[46]

While the IPA shall include in the Procurement Plan energy efficiency programs and measures "it determines are cost-effective" that were submitted by the utilities, the IPA or other stakeholders may point out reasons that the utilities and Commission may consider rejecting a particular cost-effective program and the utilities and Commission may consider those reasons in its submission and approval process. Some examples include:

1. If a bid appears to be from a grossly undercapitalized and understaffed bidder that the IPA, or the utilities, concludes will be unable to execute the program, the IPA believes that the IPA, utilities and Commission should consider rejecting the affected program. Such information would help determine whether the proposed savings are "achievable cost-effective savings." The IPA, as described in Section 7.1.3.4 does not believe there should be a "bright-line" test with these, or other factors, but rather a multi-factor analysis.
2. In the event similar or duplicative cost-effective programs are bid, the TRC is calculated with the assumption that the program is not being implemented simultaneously with such similar or duplicative programs and thus if both programs were implemented simultaneously both programs may be cost-ineffective.
3. To the extent that the standard in Section 16-111.5(d)(4) is applied directly to Section 16-111.5B energy efficiency procurements, the Commission has broader discretion to consider a variety of factors, including "lowest total cost over time," "price stability" and the inclusion of savings "to the extent practicable."[47] The IPA appreciated comments and looks forward to stakeholder discussion as part of the approval docket.

2.8 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."[48] 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.[49] 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[50];
- 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.[51]; 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.[52]

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[46] 220 ILCS 5/16-111.5B(a)(5).
[47] 220 ILCS 5/16-111.5(d)(4); *see, e.g.*, ICC Docket No. 12-0544, Final Order dated December 19, 2012 at 234-235 (applying 16-111.5(d)(4) to Procurement Plan as a whole, not individual components of the plan such as FutureGen).
[48] 220 ILCS 5/16-111.5(b)(3)(ii).
[49] 220 ILCS 5/16-111.5(b)(3)(ii).
[50] 16-111.5(b)(3)(ii)(A); 16-111.5(b)(3)(ii)(B).
[51] *Id.* at 16-111.5(b)(3)(ii)(C); 16-111.5(b)(3)(ii)(D).
[52] *Id.* at 16-111.5(b)(3)(ii)(E).

Public Act 97-0616, the Energy Infrastructure Modernization Act (EIMA), requires ComEd and Ameren to file tariffs instituting an opt-in market-based peak time rebate (PTR) program with the Commission within 60 days after the Commission has approved the utility's AMI Plan.[53] ComEd's PTR program was provisionally approved in ICC Docket No. 12-0484 and Ameren's PTR program is pending approval in ICC Docket No. 13-0105; both programs have operational and implementation issues being discussed at Staff-led workshops.[54] These programs are discussed further in Section 7.5, where demand response resource choices are examined.

2.9 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.[55] As a part of the goal, the Plan must also include electricity generated from clean coal facilities.[56] While there is a broader definition of "clean coal facility" contained in the definition section of the IPA Act[57], Section 1-75(d) describes two special cases: the "initial clean coal facility"[58] 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").[59] 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 ICC Docket No. 12-0544, the Commission approved inclusion of FutureGen 2.0 as a clean coal resource starting in the 2017 delivery year.[60] The IPA is not aware of any additional retrofit clean coal facilities seeking inclusion in the Procurement Plan. Aside from a pending appeal of the Commission's Final Order in ICC Docket No. 12-0544 regarding inclusion of FutureGen, the IPA is not aware of any change in status since approval of the 2013 Procurement Plan to FutureGen's ability to deliver clean coal electricity as anticipated.

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[53] 220 ILCS 5-16-108.6(g).
[54] *See, e.g.,* ICC Docket No. 12-0484, Interim Order dated February 21, 2013 at 32.
[55] 20 ILCS 3855/1-75(d).
[56] 20 ILCS 3855/1-75(d)(1).
[57] 20 ILCS 3855/1-10.
[58] Id.
[59] 20 ILCS 3855/1-75(d)(5).
[60] *See* ICC Docket No. 12-0544, Final Order dated December 19, 2012 at 228-237; *see also* ICC Docket No. 13-0034, Final Order dated June 26, 2013 ("Phase II" approving sourcing agreement as required in ICC Docket No. 12-0544).

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."[61] The plan has to 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.[62]

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.*[63]

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. In doing so the Agency first reviewed the forecasts from July 2012, to determine if the form and content of those forecasts support the analyses the Agency plans to undertake this year. The Agency and its consultant put a series of questions to the utilities. A similar process was then applied to the July 2013 forecasts.

This chapter contains a summary of the load forecasts for Ameren and ComEd, 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 and PJM for ComEd).

3.2 Summary of Information Provided by Ameren

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

- Ameren Illinois Company ("AIC") Load Forecast for the period June 1, 2014 – May 31, 2019 (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 Appendix 6 [Third Party Bids] and 7 [Detailed Analysis] were marked confidential and are not included in Appendix B.)

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[61] 220 ILCS 5/16-111.5(a).
[62] 220 ILCS 5/16-111.5(b)(1).
[63] 220 ILCS 5/16-111.5(d)(1).

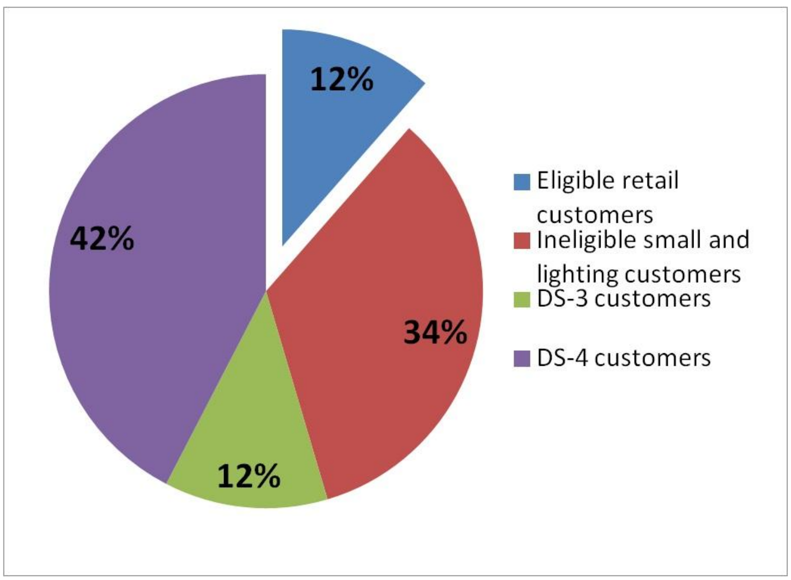
- Spreadsheets of the expected, high, and low forecasts. Supplemental spreadsheets detailed the renewable portfolio standard targets and budgets under each scenario, capacity needs under each scenario, and the impact on the expected load forecast of incremental energy efficiency programs. (Summarized in Appendix D)

Ameren 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.

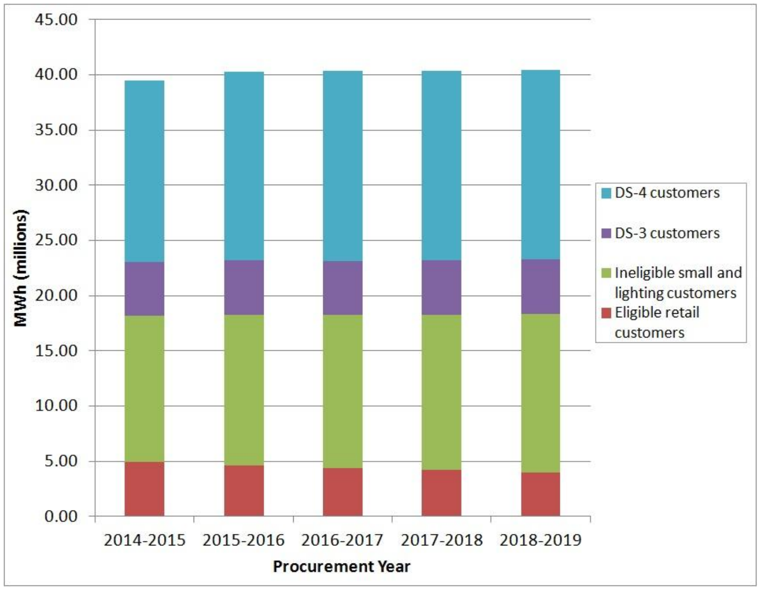
Figure 3-1 shows the annual breakdown of usage by customer class, and separates out the eligible from ineligible small and lighting customers.

Figure 3-1 Ameren Load Breakdown, Procurement Year 2014-2015



Ameren forecasts are performed on the total Ameren 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 5-year forecast by customer group.

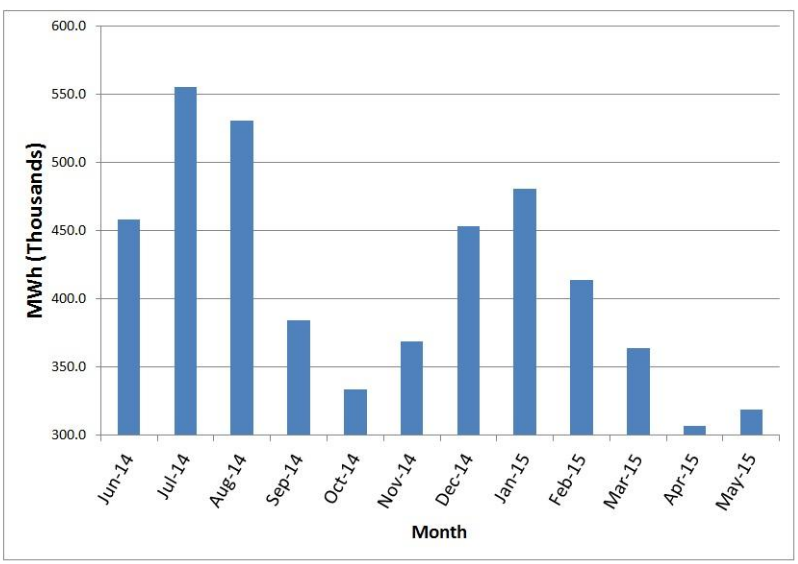
Figure 3-2 Ameren Load by Procurement Year



Ameren 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 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.

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

Figure 3-3 Ameren Eligible Retail Load* by Month, Procurement Year 2014-2015



*Total load, prior to netting QF supply

Ameren 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 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 did not define "high" and "low" cases by varying the econometric (or other) variables. Instead Ameren looked at the statistics of the residual from the model fit; the high case is somewhere between the 90% and 95% confidence level and the low case is between the 5% and 10% confidence level.

Ameren's "high" and "low" forecasts are uniform modifications of the expected case, excluding incremental energy efficiency, by rate class.[64] Specifically, in each case, a single multiplier is defined for each of the five 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 Excursion Cases

Rate Class	Low Case	High Case
DS1	0.935	1.060
DS2	0.900	1.100
DS3	0.900	1.100
DS4	0.930	1.070
DS5	0.930	1.070

Because the excursion cases are based on the statistics of the residuals, they reflect the influence of unmodeled variables. 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.

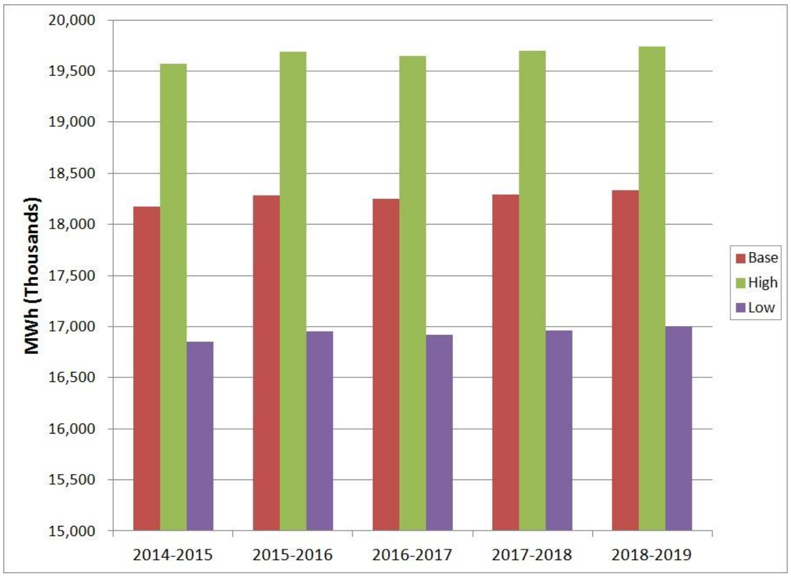
3.2.2 Weather

Ameren includes "high weather" and "low weather" in its characterization of the high and low cases. Ameren 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's total delivery service load, assuming no switching, for the non-competitive classes DS1, DS2, and DS5. The difference between the high, low and base cases show the variation Ameren attributes to macroeconomics and weather. It is about +/-9%.

[64] Ameren provided four forecast cases: an expected case, a high case, a low case, and a version of expected case that also included incremental energy efficiency not yet approved (cf. Section 7.1). While the IPA's analysis has in general been based on this fourth case, the high and low cases were computed without incremental energy efficiency.

Figure 3-4 Ameren Annual Load by Procurement Year



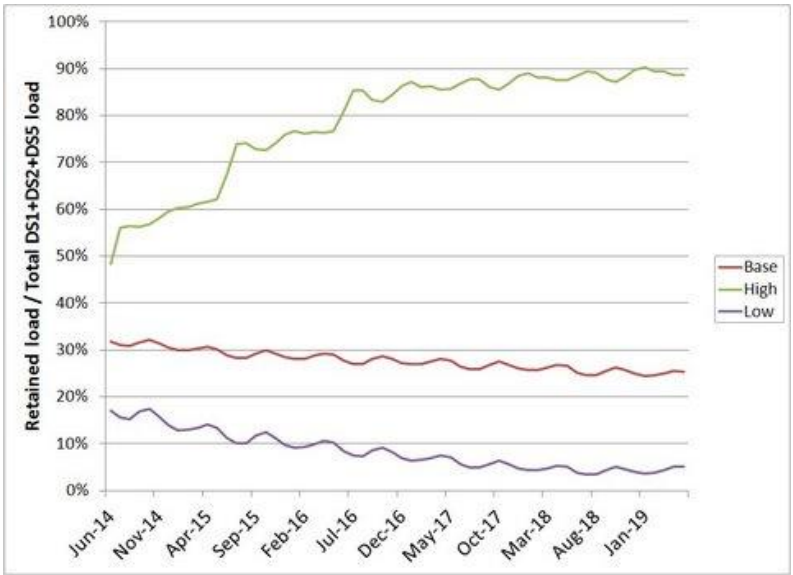
3.2.3 Switching

According to Ameren, switching, in particular municipal aggregation, is the greatest driver of load uncertainty. A wave of switching is expected in the summer and early autumn of 2013, driving the switched load to about 65-70% of residential and small commercial load. A low-load scenario would involve a higher level of switching, possibly a fourth wave of referenda leading to 95% or higher switching, so that Ameren would retain only 5% or less of the residential and small commercial customers by the end of the Plan horizon.

On the other hand, a large portion of the initial set of municipal aggregation contracts will be expiring in mid-2014. The price for utility energy supply lags the market price of energy, because the IPA's portfolios are laddered (bought over a period of several years). As the market price fell, the utility price lagged and was above market; but if the market price of energy rises, new aggregation contracts could appear more expensive than utility supply. Rising market prices could motivate a significant return to utility service beginning with the 2014-2015 procurement year.

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.

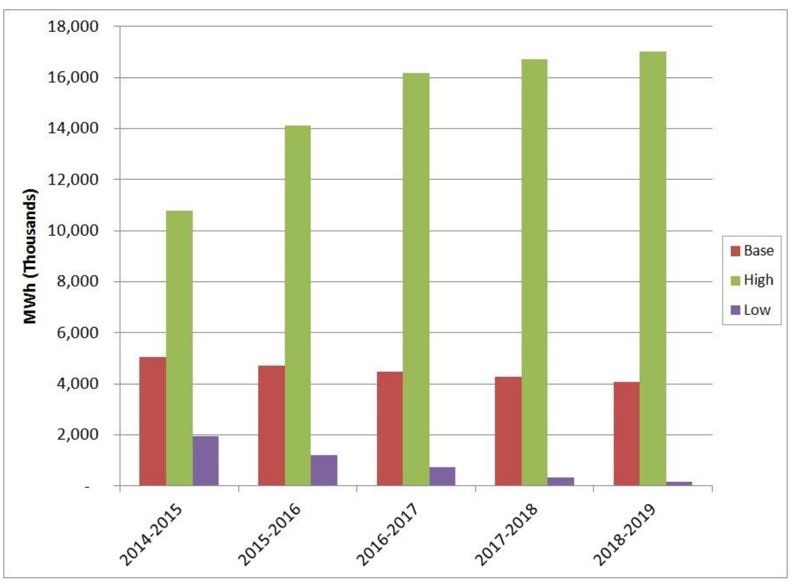
Figure 3-5 Utility Load Retention in Ameren Forecasts



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.

The load to be met by Ameren is the retained load, minus the expected supply under legacy PURPA qualifying facility (QF) contracts. Late in the forecast horizon, the hourly retained load in the low case is projected to be less than the QF deliveries, for a minority of hours implying that the utility's supply obligation could be negative in a worst case scenario. This is an indication of the extreme nature of the switching scenarios. Figure 3-6 shows the forecasted Ameren supply obligation in each case.

Figure 3-6 Utility Supply Obligation by Procurement Year in Ameren Forecasts



3.2.4 Load Shape and Load Factor

Figure 3-7 and Figure 3-8 display the hourly profile of Ameren's supply obligation in each case (relative to the daily maximum load). Figure 3-7 illustrates a 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 and base cases, although the high case is a bit peakier. 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 low-load case is definitely less peaky than the base case, especially on the lower-load day.

Figure 3-7 Sample Daily Load Shape, Summer 2014 in Ameren Forecasts

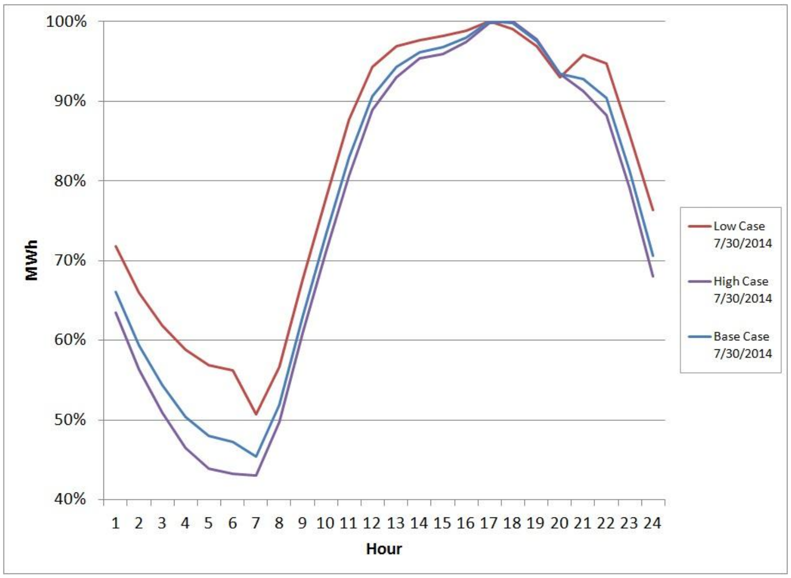
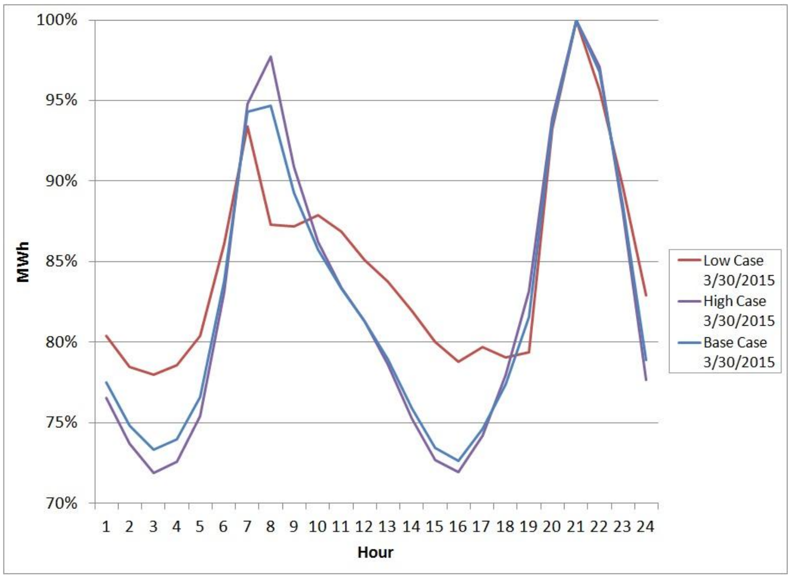


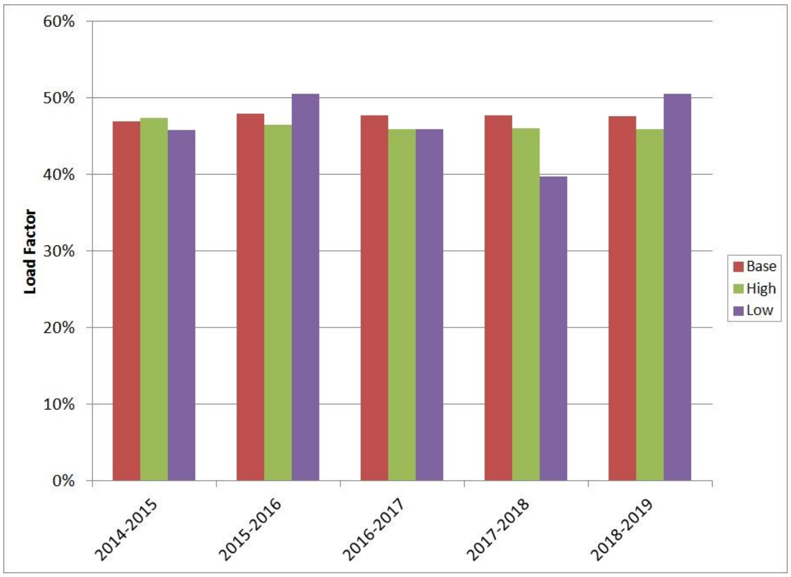
Figure 3-8 Sample Daily Load Shape, Spring 2015 in Ameren Forecasts



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. Peaky load curves have low load factors.

However, the comparison of Figure 3-9 with Figure 3-7 and Figure 3-8 does not reflect this trend: in 2014-2015 the low case is less peaky than the other cases while it has the lowest load factors. This may reflect a difference in weather assumptions between the low case and the other two cases.

Figure 3-9 Utility Load Factor by Procurement Year in Ameren Forecasts



3.3 Summary of Information Provided by ComEd

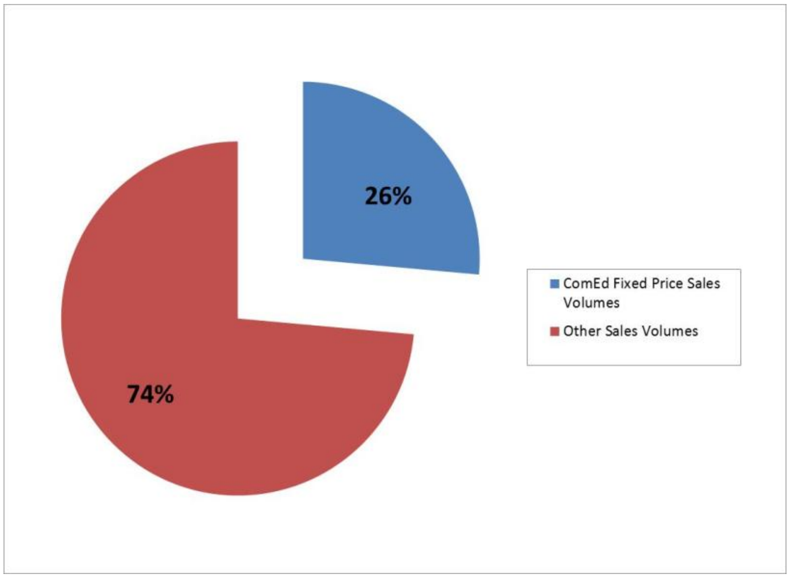
In compliance with Section 16-111-5(d)(1) of the Public Utilities Act, ComEd provided the IPA the following documents for use in preparation of this plan:

- *Load Forecast for Five-Year Planning Period June 2014 – May 2019.* 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 programs was included as four additional separate documents. (See Appendix C. Note, ComEd also provided an additional document entitled, *2013 Third Party Efficiency Program Summary of Vendor Scoring Process* which was marked confidential and is not included in Appendix C.)
- Spreadsheets of load profiles, hourly load strips, model inputs, procurement blocks, and scenario models for the base, high and low forecasts. (Summarized in Appendix E)

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 annual breakdown of usage by eligible and ineligible small and lighting load.

Figure 3-10 ComEd Composition of Eligible Customers Weather Normal Sales Volumes, Procurement Year 2014-2015



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 Composition of Eligible Customers Weather Normal Sales Volumes by Procurement Year

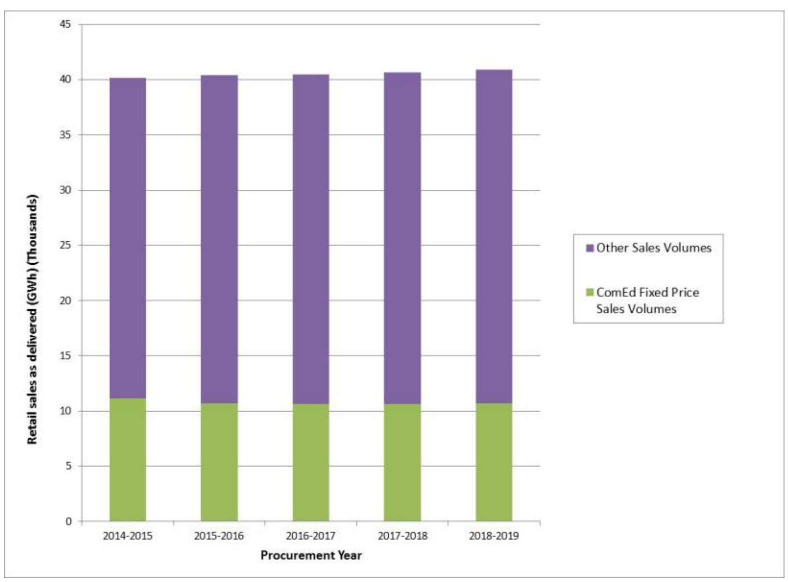
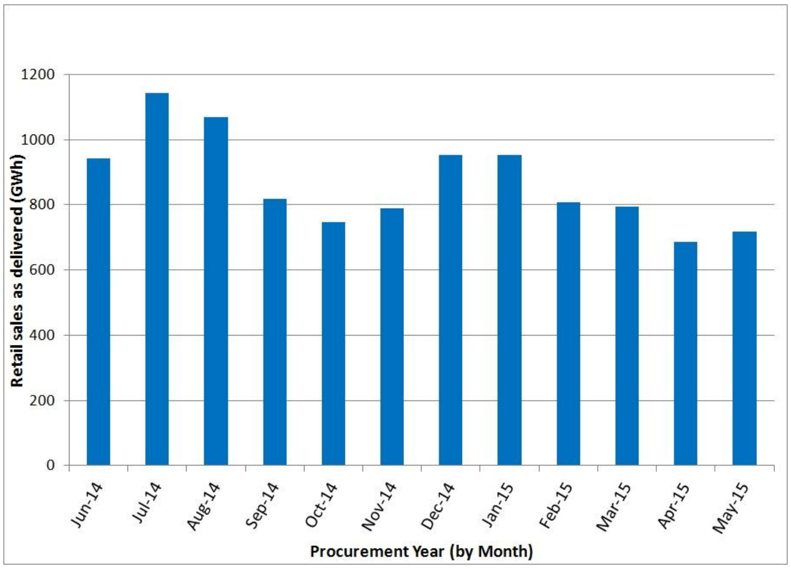


Figure 3-12 provides a monthly breakdown of the expected or base-case forecast of ComEd's eligible retail load, that is, the load of customers who are eligible for bundled supply procured under this procurement plan.

Figure 3-12 ComEd Eligible Load by Month, Procurement Year 2014-2015



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

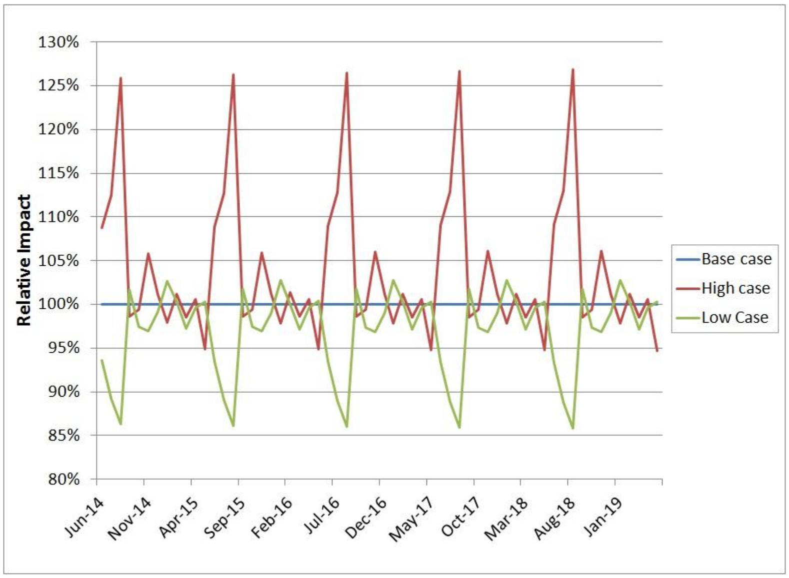
ComEd's base case load forecast is driven by a Zone Model that includes both macroeconomic variables (Gross Metropolitan Product for Chicago and Rockford, household income) and demographics (household counts). ComEd did not use this model to define "high" and "low" cases. ComEd modified the service area 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). ComEd has informed the Agency that, in its assessment, the high load case is near the bottom of the top quartile of the load growth distribution (75th to 80th percentile) and the low load case is conversely near the top of the lowest quartile of the load growth distribution (20th to 25th percentile).

3.3.2 Weather

ComEd includes "high weather" and "low weather" in its characterization of the high and low cases. The high weather case is based on observed temperatures in 1995, and the low weather case on observed temperatures in 2004. These years represent the 90th to 95th percentile and 5th to 10th percentile of weather impacts on load respectively.

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.

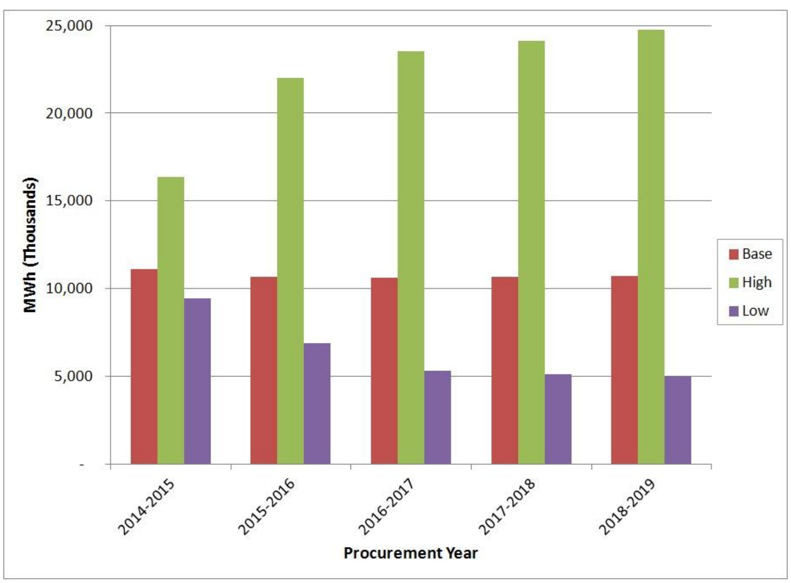
Figure 3-13 Weather Impacts in ComEd Forecasts



3.3.3 Switching

ComEd's high and low switching cases are not as extreme as Ameren's, and are based on specific event-related assumptions. The high switching (low load) case assumes an additional round of municipal aggregation referenda resulting in the departure of an additional 10% of load, and additional switching to ARES. Figure 3-14 shows the forecasted utility supply obligation in each case.

Figure 3-14 Utility Supply Obligation in ComEd Forecasts



3.3.4 Load Shape and Load Factor

Figure 3-15 and Figure 3-16 display the hourly profile of the utility supply obligation in each case (relative to the daily maximum load). Figure 3-15 illustrates a summer day, and Figure 3-16 a low-load spring day. The high case is definitely peakier on a summer day than the base case, and the low case is flatter. ComEd has not explicitly indicated QF supply in its forecast.

There is not a great deal of difference between the profiles of the high and base cases, although the high case is a bit less peaky. The low-load case is definitely peakier than the base case, especially on the lower-load day.

Figure 3-15 Sample Daily Load Shape, Summer 2014 in ComEd Forecasts

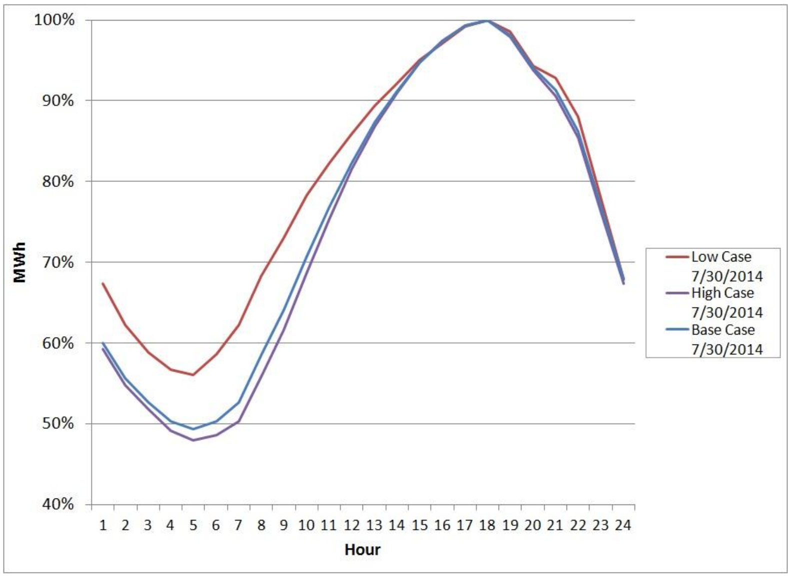
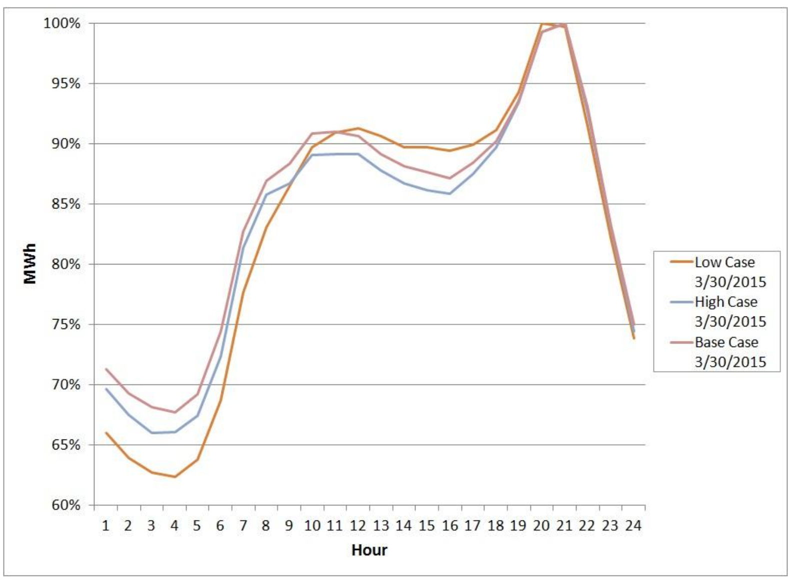
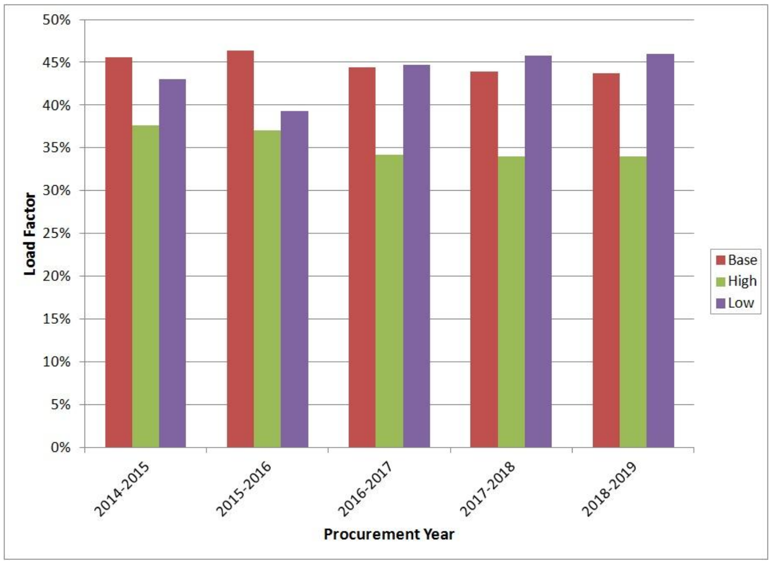


Figure 3-16 Sample Daily Load Forecast, Spring 2015 in ComEd Forecasts



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 forecast was based on an over-averaged temperature pattern (normal every day).

Figure 3-17 Utility Load Factor in ComEd



3.4 Sources of Uncertainty in the Load Forecasts

In the past, the Agency has procured or hedged power for the utilities to meet a 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 should 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 3.4.3). 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.

3.4.1 Overall Load Growth

Both utilities 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.

Ameren 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's 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 a good range of uncertainty.

3.4.2 Weather

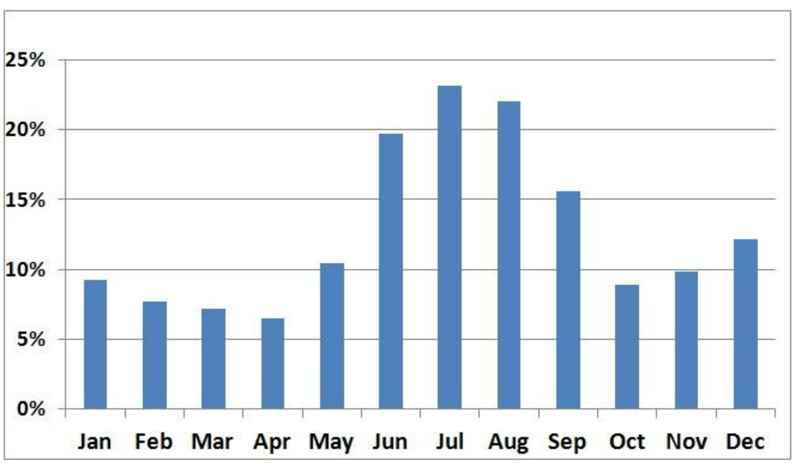
On a short-term basis, weather fluctuations are a key driver of the uncertainty in load forecasts, and in the daily variation of load forecasts around an average-day forecast. The discussion of high and low scenarios, Sections 3.2.2 and 3.3.2, notes the way that Ameren and ComEd have incorporated weather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

3.4.3 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 lower loads. More important, 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, 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.

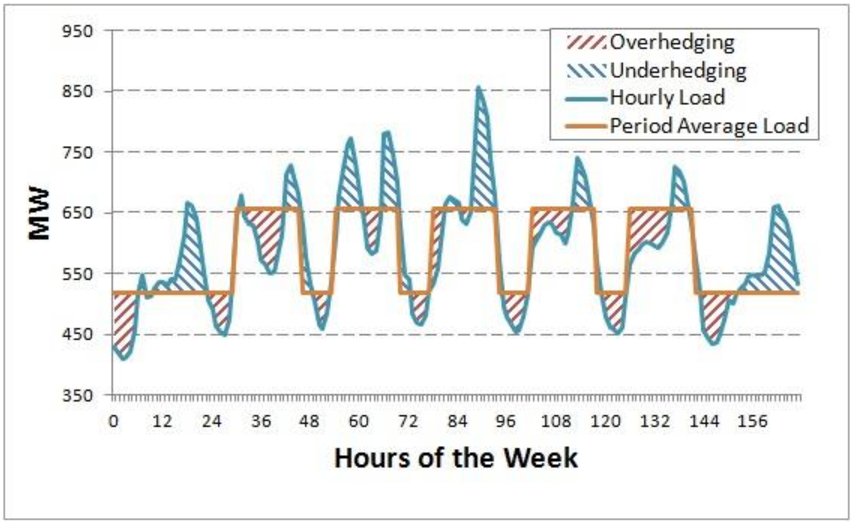
Figure 3-18 illustrates this by showing, for each month, the average historical "daily coefficient of variation" for peak period loads. It is based on historical ComEd loads from June 2002 through 2011, normalized to the monthly base case forecasts in the first procurement year. The variances of loads within each day's peak period are averaged to get an expected daily variance. That variance is 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 3-18 Coefficient of Variation of Daily Peak-Period Loads



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. 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 3-19 below:

Figure 3-19 Example of Over- and Under-Hedging of Hourly Load



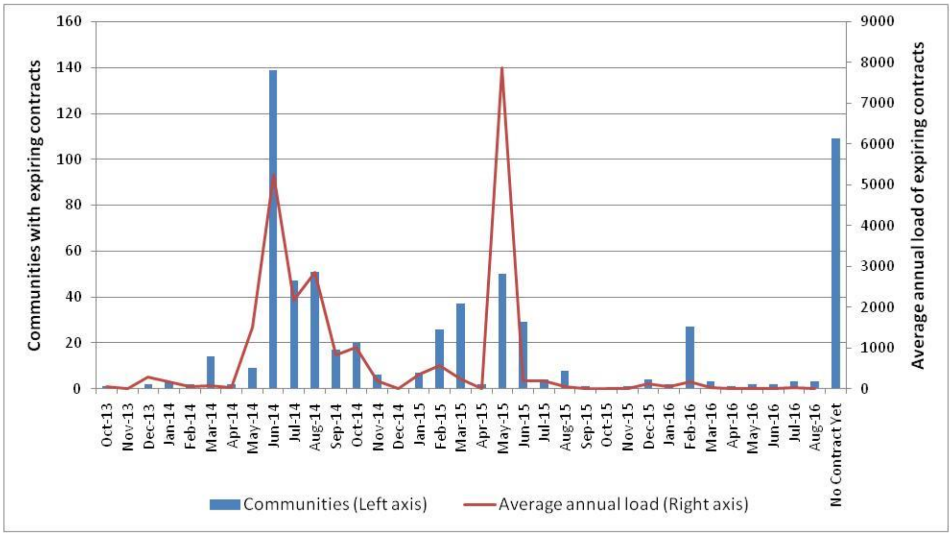
3.4.4 Municipal Aggregation

In their base cases, Ameren projects 73.0% switching by eligible retail customers by the end of the 2014-5 procurement year and ComEd projects about 74.7%. This may be approaching a saturation level; switching levels are so high that there is not much "headroom" for upwards uncertainty, and www.pluginillinois.org/MunicipalAggregationList.aspx does not, as of the date of this document, list any aggregation referenda scheduled for November 2013.

At this point the uncertainty around municipal aggregation and switching may be more related to the chance that utility load will increase from return to service or opt-out. In July 2012, ComEd assumed a 4% opt-out rate but later in the year, based on experience, they raised their assumption to 8% for single-family residential customers and 12% for multi-family customers (still 4% for non-residential customers). Ameren assumed a 10% opt-out rate in their load forecast computations.

As shown in Figure 3-20 over half the current supply contracts for municipal aggregation will expire in the 2014-2015 procurement year. It is a possibility that many of the renewal offers made by the suppliers to municipal aggregations may be out of the money 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 those hedges are above market prices, the remaining load taking bundled utility service would be subject to higher bundled rates. Both Ameren 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). The IPA notes that some multi-year municipal aggregation contracts may have early termination clauses if the supplier cannot match or beat the utility-offered supply price.

Figure 3-20 Distribution of Municipal Aggregation Contract Expirations



3.4.5 Impact of Wholesale Pricing and Market Arrangements on Switching Behavior

Customer migration behavior is particularly important because of its linkage with market prices. Utility retail tariff prices tend to lag prices in the power market for two reasons.

1. First, the IPA's procurement strategy has been to buy power in a "laddered" fashion. A large fraction of the power consumed by retail customers would have been bought forward one to two years earlier. In a period of rising prices, those forward purchases would have been priced below the current spot price (and below the current forward price), and therefore the blended price of IPA supply would be less than the current price of a new contract, e.g., a renewed municipal aggregation contract.

   The reverse is true in a period of falling power prices, as has been experienced over the last several years: the blended price of IPA supply would be higher than the contemporary price of power, or the price of new contracts. That would motivate rational consumers to depart from utility service for the price of a new contract either with an ARES or through municipal aggregation. If the market is moving into an environment of rising power prices it is equally true that consumers would be motivated to return to utility service. The forward contracts in the utilities' portfolios for 2014-2015 are currently above the forward curve (out of market).

2. Second, there are regulatory lags involved in utility rate setting. Even if the IPA supply were purchased entirely at the spot price, the monthly retail price would have been set in advance and reconciled after the fact. In a rising market the tariffs will be below the actual supply cost. Customers do eventually pay those higher prices, through a delayed balancing account mechanism. Price caps, such as the ceiling on ComEd's Purchased Energy Adjustment, introduce further delays. A customer who aggressively exercises his or her switching options would leave utility service when spot prices begin to fall, to obtain a more immediate benefit from the price reduction, and return to utility service when prices begin to rise, since he or she would be insulated from that rise for at least several months. Of course, customers may not be so aggressive in switching, and that aggressiveness may also be mitigated by regulatory and legal barriers, such as the prospect that they may have to stay on utility service for 12 months if they do not select a new supplier within two billings periods of returning to utility service.

Although it is not yet clear how governments running municipal aggregation programs and individual customers who may opt out or leave a program will act, it is likely that customers would return to utility service in periods of rising prices.[65] The Agency and the utilities would have to arrange for additional supply to cover the returning load, at a price higher than was paid for the originally forecasted load and higher than would be built into utility tariffs. Therefore, load whose return is correlated with high prices (and whose departure is correlated with low prices) represents not only load uncertainty but also an absolute price risk.

Finally, independent of market pricing, there may be other market arrangements that motivate customers to switch from or return to utility service. Some customers, or customers in some locations, may be inherently less expensive to serve and will see a benefit from moving to a retailer that can provide them a differentiated price. Others, who may find they are more expensive to serve, will be motivated to return to the uniform tariff. Customers may not have realized these differences when the initial municipal aggregation referenda were held; the costs may actually be utility delivery charges that only become visible when customers leave bundled service. For example, ComEd's current practice uses four different PLCs – one for each of the four sub-classes of residential customers. Each of these constant PLCs is the same for all customers within the sub-class, regardless of other measures of the customer's "size." Low-usage customers or aggregation groups dominated by low-usage customers will find that they are disadvantaged by ARES or municipal aggregation service, relative to bundled service. The IPA is interested in stakeholder feedback on the effect and magnitude of non-market price factors leading to government and individual decision-making.[66]

3.4.6 Individual Switching

Although switching from the utility to ARES by individual customers has some impact, Ameren and ComEd switching forecasts have been dominated by municipal aggregation. The most desirable customers to ARES would be medium and large commercial and industrial customers. Since their load has been declared competitive they are not eligible for IPA-procured default rate service. Although the IPA recognizes that many ARES do focus on individual residential switching, the IPA is not aware of a way to model or predict how many customers will leave default service for a non-municipal aggregation ARES. In the absence of such a model, it is reasonable to assume that switching behavior by individual customers 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.

3.4.7 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 obligation and the IPA does not have to procure energy for them. Ameren 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.

3.4.8 Energy Efficiency

Public Act 95-0481 also created a requirement for ComEd and Ameren to offer cost-effective energy efficiency and demand response measures to all customers.[67] Both Ameren and ComEd have incorporated the impacts of these statutory and spending-capped efficiency goals, as applied to eligible retail customers, as well as achieved and projected savings in the forecasts that are included with this Procurement Plan. 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.

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[65] The necessary timeframe or magnitude of rising prices (or, more accurately, the spread between the bundled utility rate and the best price a municipal aggregation supplier will offer) for customers to engage in this behavior is unknown, and the IPA is interested in feedback from stakeholders as to expected quantitative or qualitative parameters.

[66] The IPA believes that any proposed changes to PLCs are outside the scope of this proceeding; the IPA is simply interested in the effect of current PLCs on switching decisions.

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

3.4.9 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 this Procurement Plan contains the IPA's discussion and recommendations for demand response resources.

3.4.10 Emerging Technologies

A number of emerging technologies were described in the 2013 procurement plan. That material will not be repeated here. This plan will comment on the likely effect of two technologies on load forecast uncertainty during the projection horizon, and particularly in the first half of the projection horizon.

3.4.10.1 Advanced Metering Infrastructure

Many of the most effective emerging technologies and rate options depend on the installation of "smart meters." When the 2013 Procurement Plan was produced, the ICC had not yet approved the AMI deployment plans for Ameren and ComEd. The ICC approved a revised deployment plan for Ameren in December 2012 in which 15% of its meters will be upgraded to AMI by the end of 2015[68] and a revised AMI deployment plan for ComEd in June 2013 in which 900,000 AMI meters (out of 4.03 million, about 22%) will be installed by the end of 2015.[69] Given the necessary lag between the time that meters are installed and the point at which customers are able to make use of them with new technologies or rates, it is likely that less than 22% of ComEd customers, and less than 15% of Ameren customers, will be able to make use of smart meters by the end of the 2015-2016 procurement year. The load uncertainty associated with AMI meters and related technologies should be low for the first half of the projection horizon.

3.4.10.2 Electric Vehicles

Electric vehicles (EVs) have the potential to significantly impact electricity demand. However, while their prices have been declining, they remain expensive, and of limited range. One promising spur to adoption was battery-swapping technology. The main proponent of that technology, Better Place, went bankrupt in 2013, but the market leader in electric vehicles, Tesla Motors, subsequently demonstrated its own battery-swapping. Still, optimism about EVs must be tempered by the price of EVs, the difficulties that have faced some manufacturers (such as Fisker) and supply limitations (Tesla Motors is currently producing at a rate of only 20,000 cars per year).

The 2013 procurement plan included estimates from Ameren and ComEd totaling no more than 536,000 EVs on the road in Illinois by 2020 (the projection horizon for this plan extends to 2019) and a second estimate of 300,000 MWh of additional load per 100,000 electric vehicles. The plan forecasted an increase of 1.6 TWh of annual load by a year after the end of the projection horizon. Actual EV load will probably be much lower. This figure should be compared with the total residential and small commercial load in Ameren and ComEd service territory, which is forecasted to be over 82 TWh in the 2018 procurement year. Although EVs are a promising technology they do not appear to significantly contribute to load forecast uncertainty during the projection horizon of this procurement plan.

3.5 Recommended Load Forecasts

3.5.1 Base Cases

The IPA recommends adoption of the Ameren and ComEd base case load forecasts, both of which include incremental energy efficiency programs. The IPA's recommendation that the Commission approve the incremental energy efficiency is presented in Section 7.1.4.

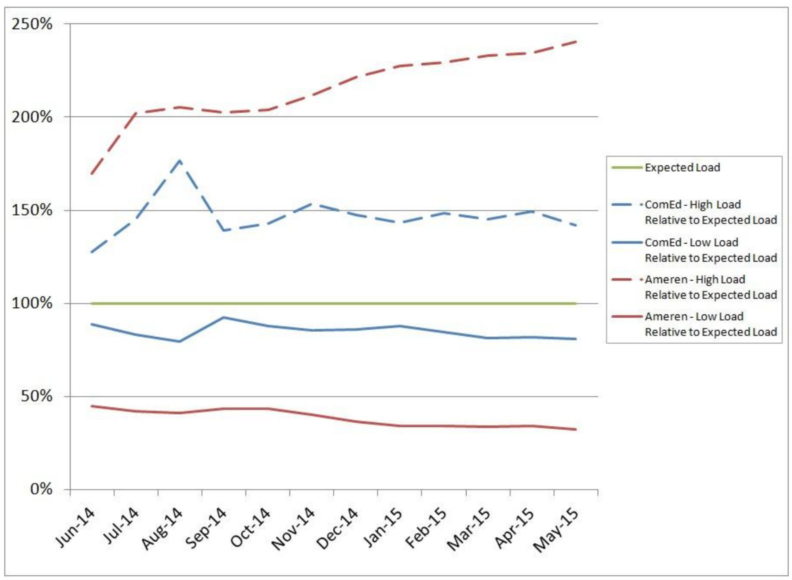
[68] Illinois Commerce Commission Order on Rehearing in docket 12-0244, December 5, 2012; also Ameren Illinois Advanced Metering Infrastructure Plan filed as Exhibit 2.1RH attached to the Corrected Petition for Rehearing in ICC Docket No. 12-0244, June 28, 2012.
[69] Illinois Commerce Commission Final Order in Docket No. 13-0285, June 26, 2013.

3.5.2 High and Low Excursion Cases

The high and low cases represent useful examples of the extent to which load can vary. Although they are primarily driven by variation in switching, Ameren correctly notes that this is the major uncertainty in its outlook. The switching variability, especially in Ameren's 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 3-21, Ameren low and high load forecasts are on average 63% lower and 117% higher during the 2014-2015 Delivery Year relative to the expected, base forecast. Comparatively, ComEd low and high load forecasts are 15% lower and 47% higher than the expected, base forecast. This reflects the differences in switching assumptions used by the two utilities.

Figure 3-21 Comparison of Ameren and ComEd High and Low Forecasts for Delivery Year 2014 - 2015



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

ComEd informed the IPA that they assessed the variation in delivery service load (before considering switching) in the high and low cases as representing the 75th to 80th percentile and 20th to 25th percentile, respectively. In its probabilistic analysis the IPA treated ComEd's high and low forecasts of retained load as representing the 95th and 5th percentile points of an underlying load distribution. Ameren had described the high and low delivery service forecasts as being the 80th to 90th and 10th to 20th percentiles respectively, and the associated switching forecasts were also more extreme, so the IPA treated Ameren's high and low forecasts of retained load as the 97.5th and 2.5th percentiles of an underlying distribution.[70]

[70] As a technical note, the "percentiles" are not the same as the probabilities one would assign in constructing a discrete distribution for probabilistic analyses. For example, if one were to construct a discrete distribution using the mean and the 10th and 90th percentile points of a normal distribution, and assign probabilities in such a way as to match the mean and variance of the (original) normal distribution, then the probability weight on the mean would be 39.1% and the weights on the extremes would each be 30.45%.

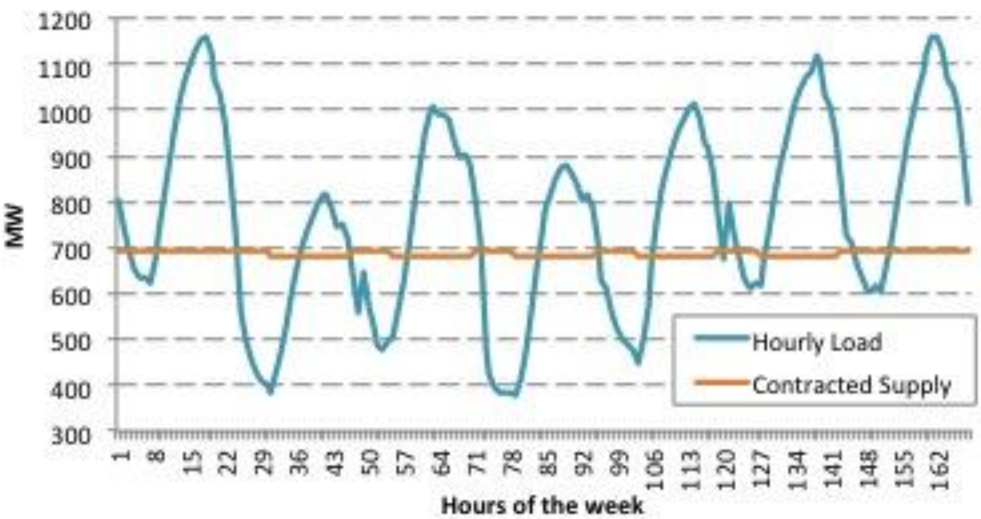
4 Existing Resource Portfolio and Supply Gap

The IPA has historically purchased supply in standard 50MW on-peak, off-peak, and around-the-clock blocks. The history of the IPA energy purchases is available on the IPA website[71].

These purchases are driven by the supply requirements outlined in the current year procurement plan and are executed through a competitive procurement process. This procurement process is administered and monitored for the Commission by independent third parties.

In addition to purchasing block contracts, Ameren and ComEd rely on the operation of their RTOs (MISO and PJM respectively) to balance their loads and consequently incur additional costs. During on-peak hours, purchased energy blocks may not fully cover the load therefore triggering the need for spot energy purchases from the RTO. Similarly, during off-peak hours over-supply may occur, prompting the utilities to sell their excess-energy to the RTOs at a low off-peak hour price. This is illustrated in Figure 4-1 where Ameren's hourly load oscillates between 377MW (minimum off-peak hour load) and 1162MW (maximum peak hour load) for the first full week of August 2014 while the hedge portfolio varies only between 682MW and 698MW. Note that ComEd is currently under hedged in every hour of the June 2014 to May 2019 period relative to the expected forecast and (absent additional purchases) would be expected to rely on the operation of PJM in every hour to meet its load.

Figure 4-1 Ameren Hourly Supply Gap - First Full Week of August 2014



The IPA procurement plans are based on a supply strategy designed, among other things, to manage 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.

Prior to the 2013 Procurement Plan, the first year of the 3-year procurement plan was hedged at 100% (meaning that energy contracts would fully cover the demand) while the second and third years would only be hedged at 70% and 35% respectively. As part of the 2013 Procurement Plan and based on suggestions from the Commission staff, the IPA considered a revision to this strategy (for the energy products only[72]) to account for declining market prices and accelerating customer switching. This proposal was the first year

[71] http://www2.illinois.gov/ipa/Pages/Prior_Approved_Plans.aspx.

[72] In the 2013 Procurement Plan, the IPA recommended retaining the 100%/70%/35% hedging strategy for purposes of Ameren's capacity requirements until such time as MISO demonstrates a robust FERC-approved capacity auction.

would be hedged at 75% while the second and third year would be hedged at 50% and 25% respectively. However, because no procurement was required, the IPA recommended that the hedging strategy be revisited in future Plans.

Because of the lack of visibility and liquidity of the energy markets and to limit the ratepayers' exposure to unnecessary price risk and cost, the IPA has not purchased any energy beyond a 3-year term horizon, except for long-term procurements which were mandated by the Legislature. These include:

- A 20-year bundled REC and energy purchase, starting in June 2012, made by Ameren and ComEd in December 2010.
- The February 2012 "Rate Stability" procurements mandated by Public Act 97-0616 for block energy products covering the period June 2013 through December 2017; there were also associated REC procurements but they do not impact the (energy) resource portfolio.

Due to the reductions in rate revenue attributable to customer switching, ComEd has been obliged to curtail its existing long-term renewable contracts in order to keep the cost of renewable energy resource under the statutory cap for the 2013-2014 delivery year (i.e., the year commencing June 1, 2013 and ending May 31, 2014). Possible curtailment for the 2014-2015 delivery year for both ComEd and Ameren is addressed in Section 8.2 of this plan.

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 address these gaps is described in Chapter 7.

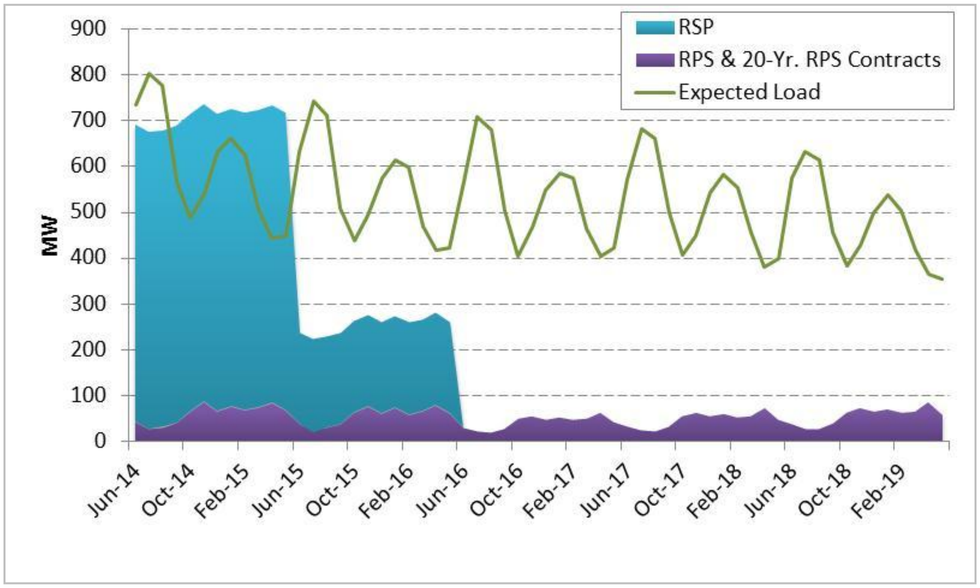
4.1 Ameren Resource Portfolio

Figure 4-2, Figure 4-3, and Figure 4-4 show the current gap in the Ameren supply portfolio for the June 2014-May 2019 planning period, using the average, high and low load on-peak forecast described in Section 3.2.

The Rate Stability Procurements (RSP) mandated by SB1652, and Ameren's existing contract portfolio, including long-term renewable resource contracts (assuming no curtailments), should cover the projected load for the 2014-2015 delivery period, with the exception of the months of June, July and August. However, additional energy will be required in 2015-2016 and beyond.

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

Figure 4-2 Ameren's On-Peak Supply Gap - June 2014-May 2019 Period - Expected Load Forecast, No Curtailment of Renewable PPAs



Under the high load forecast scenario, Ameren will be consistently short starting as early as June 2014. The average supply gap for peak hours of the 2014-2015 delivery period is estimated to be 586MW.

Under the low load forecast scenario, Ameren would not require any additional energy procurement until June 2016 and Ameren's supply portfolio would actually be in excess during the peak hours of the 2016-2017 period in average by 11MW (shortfalls would only occur during the summer of 2016).

Figure 4-3 Ameren's On-Peak Supply Gap - June 2014-May 2019 Period - High Load Forecast, No Curtailment of Renewable PPAs

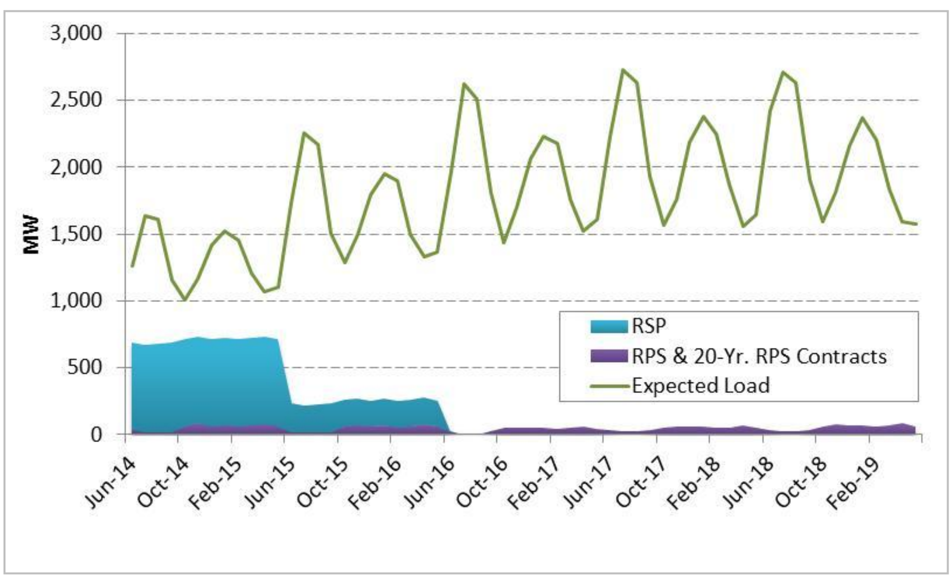
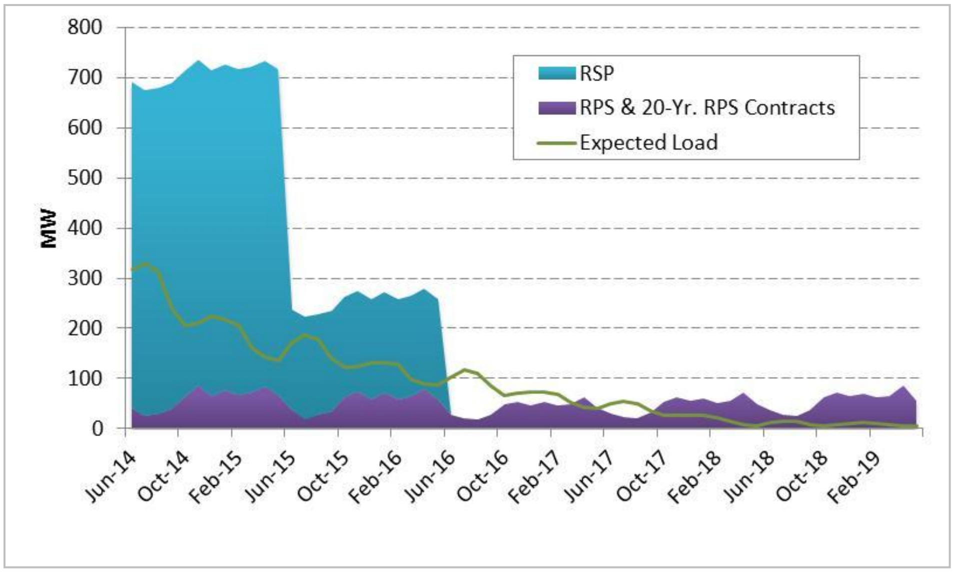


Figure 4-4 Ameren's On-Peak Supply Gap - June 2014-May 2019 Period - Low Load Forecast, No Curtailment of Renewable PPAs

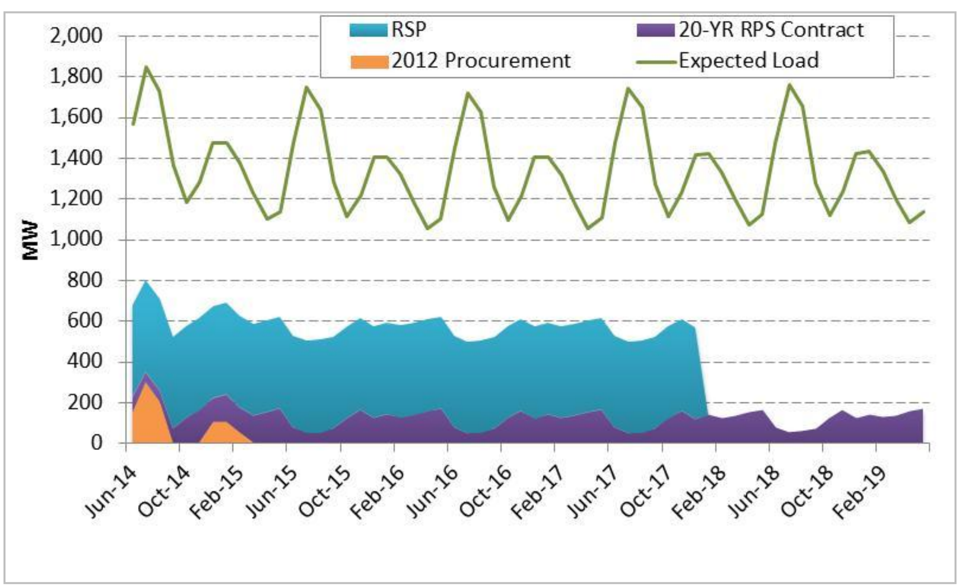


4.2 ComEd Resource Portfolio

Figure 4-5, Figure 4-6, and Figure 4-7, show the current gap in the ComEd supply portfolio for the June 2014-May 2019 planning period, using the average, high and low load on-peak forecast described in Section 3.3.

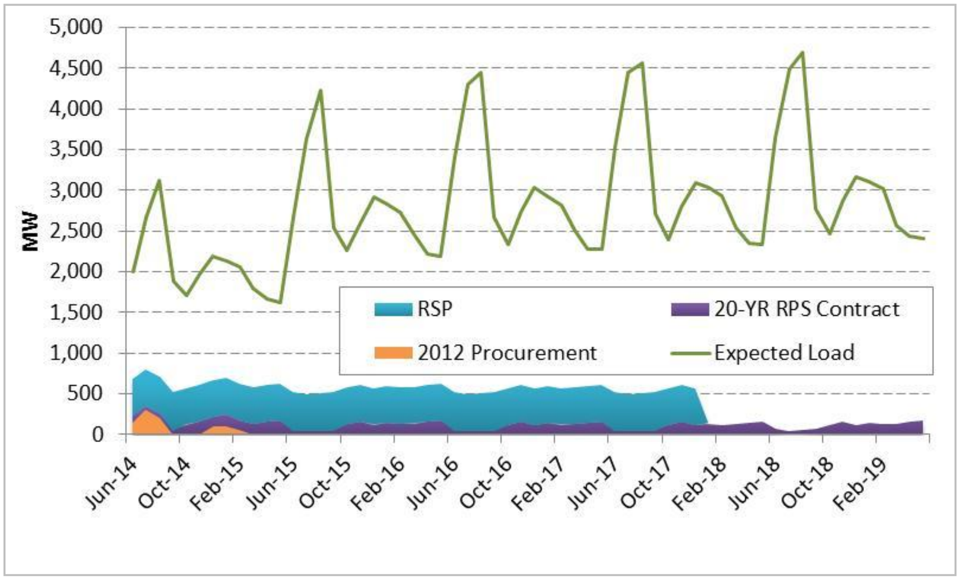
ComEd's current energy resources will not cover load starting in June 2014. The average supply gap during peak hours for the 2014-2015 delivery year is estimated to be 771MW. The 2013 Procurement Plan explicitly stated a change in the hedging plan, so that only 50% of expected 2014/2015 load would be hedged a year ahead. This gap is expected to remain relatively constant until the Rate Stability Procurement (RSP) contracts terminate in January 2018.

Figure 4-5 ComEd's On-Peak Supply Gap - June 2014-May 2019 period - Expected Load Forecast, No Curtailment of Renewable PPAs



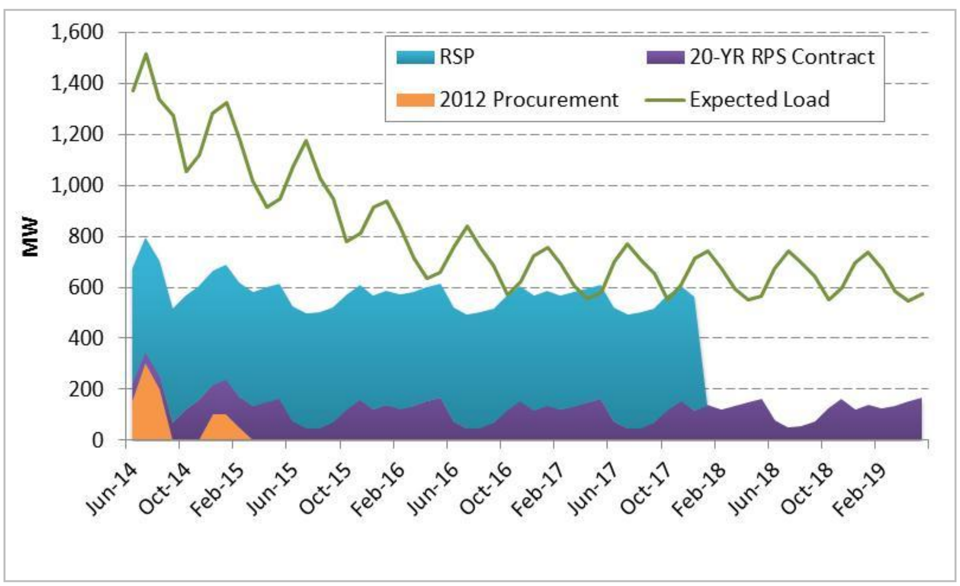
Under the high load forecast scenario, ComEd will be consistently short during the whole study period. The average supply gap for peak hours of the 2014-2015 delivery period is estimated at 1429MW.

Figure 4-6 ComEd's On-Peak Supply Gap - June 2014-May 2019 Period - High Load Forecast, No Curtailment of Renewable PPAs



Under the low load forecast scenario, ComEd will also be consistently short during the study period except for the months of April, May and October 2017.

Figure 4-7 ComEd's On-Peak Supply Gap - June 2014-May 2019 Period - Low Load Forecast, No Curtailment of Renewable PPAs



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, in order for the Illinois market to properly function, the overall RTO markets (e.g. MISO and PJM) must provide sufficient resources to satisfy the load of all customers. This section reviews the likely load/resource outcomes over the planning horizon to determine if the current system is highly likely to provide the necessary resources such that customers will be served with adequate and 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.

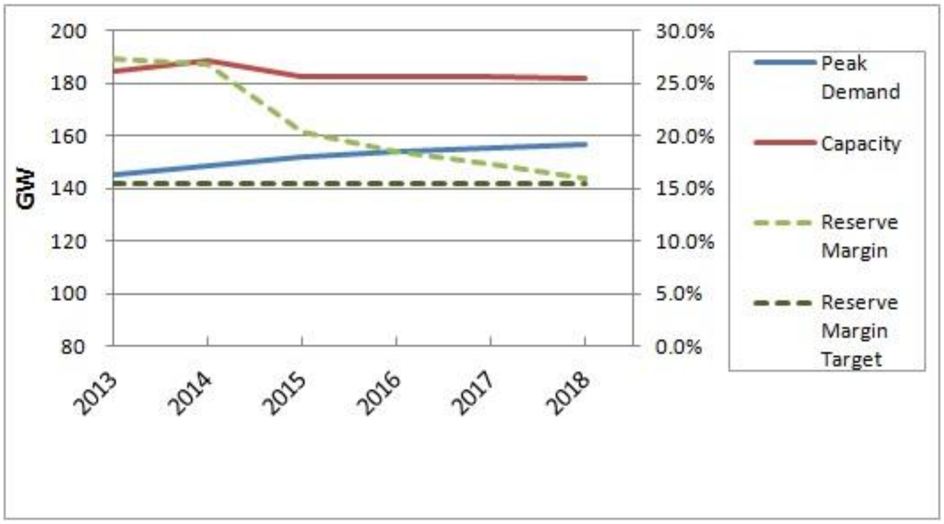
From review of these entities' most recent documentation, it is clear that over the planning horizon both PJM and MISO will maintain adequate resources to meet the collective needs of customers in those regions.

5.1 Resource Adequacy Projections

In PJM, capacity is largely procured through PJM's capacity market, Reliability Pricing Model ("RPM"), which was approved by FERC in December 2006. RPM is a forward capacity auction through which generation offers 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. The commitment period is also referred to as a delivery year ("DY").[73] In addition to the BRAs, up to three incremental auctions are held, at intervals 23, 13, and 3 months prior to the DY.[74] As outlined in Figure 5-1, PJM is projected to have sufficient resources to meet load plus required reserve margins from 2013-2018, with projected reserve margins averaging over 20% during this time frame. This is approximately 5% above the 15.6% reserve margin requirement.

[73] A DY is June 1 through May 31 of the following year.
[74] To the extent the 1st and 3rd incremental auctions are not needed, they may be cancelled by PJM. The 2nd incremental auction is held to procure capacity to meet the deferred short-term resource procurement.

Figure 5-1 PJM NERC Projected Supply and Demand



MISO's capacity market construct, Module E-1, creates a framework for electric utilities and capacity resources to enter into bilateral agreements for capacity. Specifically, Module E-1 is a resource adequacy program that requires the region's load-serving entities to procure sufficient capacity resources to meet their peak load plus target reserve margin.[75] Under Module E-1, a load-serving entity can procure resources to meet its resource adequacy requirements by offering or self-scheduling resources in the annual auction or by submitting a Fixed Resource Adequacy Plan ("FRAP") to demonstrate sufficient resources have already been procured. As outlined in Figure 5-2, MISO is projected to have sufficient resources to meet load plus required reserve margins from 2013-2018, with reserve margins averaging over 22% during this time. This is approximately 5% above the 17.5% reserve margin requirement.

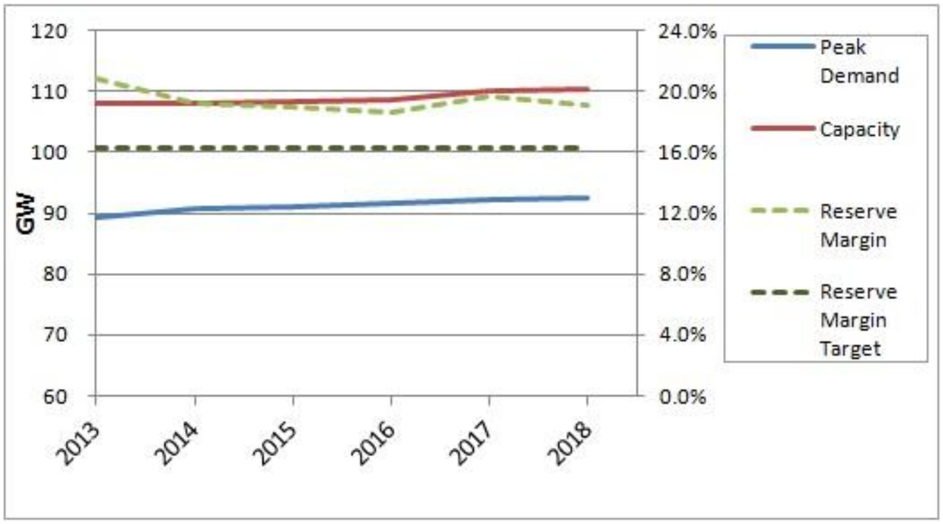
5.2 Locational Resource Adequacy Needs

The RTO-based reliability assessments examined above are important measures of resource reliability in Illinois because the Illinois electric grid operates within the control of these two RTOs. While changes are projected to occur in the RTOs, as outlined below, the IPA concludes that it does not need to include any extraordinary measures in the 2013 Procurement Plan to assure reliability over the planning horizon.

The integration of Entergy into MISO, which will create the MISO Southern Region and is planned for December 2013, will provide more generation to be dispatched and bid into the MISO markets (the load/resource balance associated with the Southern Region is not reflected in Figure 5-2 as it has yet to be incorporated in NERC projections).

[75] An LSE's reliability requirement is based on either planning reserve margins (PRM) determined by MISO, based on a loss of load expectation of one day in ten years, or state-specific standards.

Figure 5-2 MISO NERC Projected Supply and Demand



An increase in capacity resources exporting into PJM (7,500 MW in total representing an incremental 4,000 MW from the previous year's auction) is reported in the 2016/17 Base Residual Auction.[76] This substantial increase in imports for PJM is a positive development with respect to PJM's capacity market, but may also indicate less confidence in MISO's Module E-1 anticipated pricing and/or liquidity to the extent imports are coming from this region.

5.3 Operational Adequacy

MISO has discussed setting requirements for upward and downward ramping capacity. The concept is that at least a specified fraction of the resource adequacy would have to be met by capacity capable of meeting a flexible ramping standard. To date, no such requirement has been incorporated into Module E-1.

[76] Of the 7,500 MW of total net imports, approximately 4,800 had firm transmission service into PJM. The remaining 2,700 have submitted requests for firm transmission service, but have yet to receive it. This situation adds some uncertainty regarding the ability of those capacity resources without firm transmission rights into PJM to meet their capacity obligations for the 2016/17 delivery year.

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."[77]

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.*[78]

This chapter discusses and assesses risk in the supply portfolio, as well as tools and strategies for mitigating them. Developing a strategy requires knowledge of the risk factors associated with energy procurement and delivery and of the tools available to manage those risks. The first section describes the risk factors themselves. These include some risk factors identified in the previous sections. The balance of the chapter identifies and analyzes the tools available to manage those 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.

Sections 6.4 through 6.7 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 is based on estimates and cost differences are trued up after the fact through the Purchased Energy Adjustment (PEA). Section 6.4 provides a historical summary of PEA rates as a guide to the historical impact of risk factors. Section 6.5 includes estimates of the cost impacts of risk factors based on a Monte Carlo simulation model, and compares several forward hedging strategies. Section 6.7 focuses on full requirements tranche contracts. Tranche contracts can eliminate the uncertainty in supply cost, and the Monte Carlo model is used to estimate the associated price premium.

Finally, Section 6.8 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 impact volume risk. Accurate customer consumption profiles, load growth projections, and weather forecasts impact both the total energy requirement and the shape of the load curve. Sections 3.2 and 3.3 describe the load forecasting processes undertaken by Ameren and ComEd respectively. This section discusses the risk factors associated with those forecasts.

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[77] 20 ILCS 3855/1-20(a)(1).
[78] 220 ILCS 5/16-111.5(b)(3)(vi).

6.1.1.1 Load Profiles

The load forecasts of both utilities start by developing a system-wide forecast. Multipliers are applied to eliminate load that has switched to ARES service or municipal aggregation. Customer groups that have been declared competitive – medium and large commercial and industrial customers – are removed entirely. The use of a multiplier assumes the profile of non-switched load and switched load are equivalent. If the switched loads have different load shapes from the retained loads then the profiles that are the basis for the forecast do not represent actual load shapes.

6.1.1.2 Load Growth Projections

Ameren does not explicitly separate uncertainty in load growth from customer migration and weather uncertainty, all three of which are combined in the definition of high and low scenarios. The high and low cases represent a variation of ±9% in service area load.

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.

6.1.1.3 Weather Forecast

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. Ameren and ComEd have incorporated weather variation into their high and low load forecasts. Ameren treats weather uncertainty together with load growth uncertainty. ComEd's high and low forecasts are built around two sample years and the historical weather affects impacting forecasted load variability within the year.

6.1.1.4 Technology Impacts

The deployment of smart meters can provide customers with a better understanding of the relationship between consumption and pricing. This knowledge may lead to changes in consumption patterns. It also may allow ARES to target specific customers. For example, ARES may be able to identify and target customers with flatter or more predictable loads.

Energy efficiency programs and the introduction of customer generation can also impact consumption patterns. Weatherization and efficient appliances will reduce the total volume of energy required. The intermittent character of small-scale wind and roof-top solar will impact both the total volume and load shape.

6.1.1.5 Customer Switching

Ameren and ComEd forecast the load to be served by subtracting from the retail load, in classes that have not been declared competitive, the fraction of load expected to be served by ARES directly or through municipal aggregation.

In their base cases, Ameren projects 73.0% switching among eligible retail customers by the end of the 2014-2015 delivery year; ComEd projects about 74.7%. No additional municipal aggregation activities are forecast. At these high migration values, switching may be approaching saturation.

The uncertainty around customer switching appears to be more related to the chance that utility load will increase from return to service. Over half the current supply contracts for municipal aggregation will expire in the 2014-2015 procurement year. If ARES and municipal renewal offers are more expensive relative to utility bundled supply prices, there may be a considerable amount of return to utility service. On the other hand, switching could be higher than expected resulting in an over-hedged position. Expanding on the hypothetical, assuming that those hedges are above market prices, the remaining load taking bundled utility service would be subject to higher bundled rates.

6.1.2 Price Risk

The price the Ameren and ComEd supply customer pays for electricity consists primarily of the price of energy procured in the forward and spot markets (Sections 6.1.2.1 and 6.1.2.2 as well as 6.1.2.7) the cost of capacity to meet resource adequacy requirements (Section 6.1.2.3), and the cost of delivery (Sections 6.1.2.4 through 6.1.2.6), plus additional charges related to RPS compliance.

6.1.2.1 Energy

Spot market electricity prices are volatile. Purchasing electricity in forward markets can reduce price risk. On-peak, off-peak, and around-the clock products are offered for various time periods from next day through several years. The price of the hedges to be bought in each subsequent year is unknown because the future price cannot be known in the present.

6.1.2.2 Real-Time Balancing

Forward contracts are based on the procurement of a block of energy over multiple hours. Customer consumption changes hourly. For example, the portion of an energy block that is not consumed during the hour starting at 10 AM cannot be moved to the hour starting 2 PM when consumption is greater than the energy block. The day ahead forecast excess energy for the hour starting at 10 AM is sold first into the RTO's day-ahead market and any imbalance due to actual load deviations is settled in the real-time balancing market. Likewise the shortfall of energy required for the hour starting at 2 PM is purchased from the day-ahead market and any imbalance due to actual load deviations is settled in the real-time balancing market. The volume and price sold at 10 AM do not necessarily match the volume and price purchased at 2 PM.

6.1.2.3 Capacity

ComEd is a member of PJM. PJM holds annual auctions to procure capacity through its Base Residual Auction (which occurs three years and one month prior to the delivery period) and all subsequent Incremental Auctions. The clearing price for the capacity purchased through these auctions is the Final Zonal Capacity Price that PJM uses to price ComEd's Daily Unforced Capacity (UCAP) Obligation. ComEd, like nearly all PJM Load Serving Entities, fulfills its capacity obligation through relatively passive participation in the PJM Reliability Pricing Model as a price taker. Specifically, ComEd pays PJM the resulting Final Zonal Capacity Price times ComEd's daily UCAP Obligation.

Ameren is a member of MISO. MISO also has a capacity requirement and has instituted its own Planning Resource Auction (PRA). The PRA covers the prompt year. The 2013-14 delivery year was the first year in which Ameren fulfilled its Planning Reserve Margin Requirement (PRMR) by participating in the auction. Although the bulk of Ameren's Zonal Resource Credits (ZRCs) were purchased in the 2012 procurement event, Ameren participated in the auction by offering to sell into the PRA all ZRCs acquired by Ameren through previous IPA procurement events as a price taker and receive the auction clearing price. Ameren will pay the same auction clearing price for its entire PRMR, which is updated on a daily basis to take into account retail switching.

6.1.2.4 Ancillary Services

Ancillary services consist of regulation to correct short-term load changes, and energy reserves to protect services from unexpected shortages. They support reliable delivery of energy. A load serving entity's (LSE's) obligation for these services can be met by self-provision, by contracting with another party, or through the RTO's reserve market. Bilateral contracting for ancillary services is not very liquid; therefore most LSEs are exposed to the RTO's ancillary service pricing.

6.1.2.5 Transmission

The delivery of procured energy resources requires the reservation of adequate transmission capacity to transport the energy to customer locations. LSEs generally use network transmission service. Transmission service is purchased on a first-come first-serve basis. Energy contracts that call for delivery at the customer location shift transmission price risk to the seller. The pricing of transmission service is FERC regulated and tends to be transparent.

6.1.2.6 Congestion

Transmission congestion occurs when the desired flow of power on a transmission path exceeds the path's capacity. The RTO runs a day-ahead market to identify and reschedule flows. The cost of this service is charged to entities scheduling delivery into a congested load zone. Financial Transmission Rights (FTRs) are hedging instruments used to mitigate congestion risk and Auction Revenue Rights (ARRs) allocate to transmission customers (both firm and network) the revenues resulting from the auction of FTRs. LSEs can use these revenues to offset congestion charges.

6.1.2.7 Correlation Between Volume and Price Risk Factors

Customer switching decisions may be influenced by the difference between utility and third party provider pricing. Customer switching behavior impacts volume risk. Variability in utility customer volume impacts price risk.

IPA's historic procurement strategy has been to buy power in a "laddered" fashion. A large fraction of the power consumed by retail customers was bought forward one to two years earlier. In a period of rising prices, those forward purchases may be priced below market. Therefore the blended price of utility supply may be less than the current price of an ARES or municipal aggregation offer. This price difference may result in increased migration back to the utility. The reverse is also true: higher utility supply costs may increase switching away from the utilities.

These trends may be intensified if there is a lag in reflecting the utility's energy costs in customer rates. Slowly rising rates will increase switching to the utility. Slowly dropping rates may increase migration from the utility.

Volume changes resulting from these pricing differences may result in additional price risks.

6.1.3 Hedging Imperfections

6.1.3.1 Procurement Supply Shape

The standard on-peak and off-peak block energy products do not reflect each hour's load. These products provide a constant volume and hourly price across a fixed number of hours. Hourly energy prices vary across the day and within each of the peak and off-peak periods. Load also varies within those periods and a great deal of that variation is predictable. Energy costs more when demand is high and less when low. Therefore, fixed volume and price purchases by themselves give an inaccurate forecast of the cost of energy to serve load and provide only a partial price hedge.

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 risk will still exist because the actual load is usually greater or less than the average.

6.1.3.2 Procurement Location versus Customer Location

Hedge contracts for energy located remotely from the load location have transmission access and congestion risks. This is unlikely to be a problem with hedge contracts that deliver to the LSE's load zone, as is the case with existing hedges for which the IPA has procured.

6.1.3.3 Renewable Energy

Renewable energy procurement requirements met through the purchase of generation output are subject to intermittency. The cost to cover this intermittency may not be hedgeable, because the IPA procures renewable products (such as RECs or energy on an as-generated, rather than as pre-scheduled, basis) that are not comparable to standard block energy products. This risk factor was discussed at length in the Agency's 2013 report on the cost and benefits of renewables.[79]

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 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 PPAs (Power Purchase Agreements) are structured as Contracts for Differences. The utilities do not purchase and take title to electricity. The utilities' supply positions, other than RTO spot energy, are price hedges.

Physical electricity supply and load balancing for ComEd and Ameren are coordinated by the respective RTOs (PJM and MISO respectively). ComEd and Ameren are considered Load Serving Entities (LSE) by the RTOs. Each RTO provides day-ahead and real-time electricity "spot pricing". 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

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

Unit-specific hedges are contracts for the output of a specific generator. Contractually they are sometimes structured as financially-settled swaps. The selling counterparty (i.e., generator) pays the hourly spot LMP to the buyer (i.e., LSE), and receives from the buyer either a fixed payment per MWh or a payment computed from a floating index (as in the case of a contract indexed to the price of fuel). The amount of the payment for each hour is the difference between these two $/MWh values and a notional energy quantity, which equals the volume of energy dispatched by a specific generating unit or a fixed fraction of the dispatched volume. Unit-specific hedges may be categorized based on the control that the buyer has over the unit's dispatch.

- <u>As-available.</u> In this case the buyer cannot instruct the unit to generate, although in some cases the buyer has a limited right to curtail the generation. As-available hedges usually involve intermittent renewable generators that have an uncontrollable energy source, or which depend on the availability of energy as a byproduct of an economically independent industrial process (e.g., cogenerators that

[79] Illinois Power Agency, Annual Report: The Costs and Benefits of Renewable Resource Procurement in Illinois Under the Illinois Power Agency and Illinois Public Utilities Acts, Submitted to the Illinois General Assembly and the Illinois Commerce Commission Pursuant to PA 97-0658, March 29, 2013.

are QFs). In an as-available hedge the payment received by the generator is usually a fixed amount per MWh. The 20-year renewables contracts entered into by ComEd and Ameren in 2010 are examples of unit-specific, as-available energy hedges. Actually they are unit-specific as-available combinations of energy hedges and REC supply contracts.

- Baseload. In this case the generator is assumed to operate around the clock except for outages. There can be notice provisions or performance standards that are intended to limit the impact of forced outages and provide certainty around the timing of maintenance outages. The payment received by the generator may be a fixed amount per MWh or an amount indexed to a fuel price.
- Dispatchable. In a dispatchable contract the buyer has the right to schedule the generator's operation, except for outages. They are like options exercised each hour, subject to physical constraints on the unit's ability to modify its generation level. The payment received by a dispatchable generator will often be indexed to a fuel price, in which case the dispatchable contract is similar to a physical tolling contract. There is usually an initial cost to the buyer to enter into a dispatchable contract, equivalent to an option premium. As-available or baseload contracts often have no initial cost or option value.

6.2.1.2 Unit-Independent Hedges.

Other available hedges do not depend on the production of any generating unit or combination or units. From the standpoint of a generation owner selling such a hedge it is "portfolio-based" rather than unit-specific because it depends on the owner's entire portfolio.

- Standard forward hedges. A forward contract for energy is a contract for the delivery of energy at a future date, or over a fixed period of time in the future, at a predetermined fixed price. A financial forward hedge is a fixed-for-floating swap where the selling counterparty receives a fixed payment for energy in each hour, and pays the RTO LMP to the buyer. A notional hourly energy volume multiplier is used to determine the payments. The period of time and the notional volume are defined in the contract. Standard wholesale forward contracts cover one or more months. A typical contract sold in the winter for summer delivery would cover July and August, or the third calendar quarter. While in May, one would be more likely to find separate contracts for the following July and August. A "7x24" contract has a constant notional amount in each hour. A "5x16 peak" contract has a constant notional amount in each hour from the hour ending ("HE") 7 AM to HE 10 PM (prevailing time) on weekdays except for holidays,[80] and zero in other hours. An "off-peak" contract has a constant notional amount in the hours in which a peak contract has a zero notional amount.
- Shaped forward hedges. A shaped forward hedge is similar to a standard forward hedge except that the notional volume can vary across the hours of the delivery period. For example, the notional volume could be proportional to the average expected customer load in each hour, to hedge against the correlation of price risk with load. Alternatively a shaped forward hedge could be based on a different time period. For example, there could be a fixed notional volume only in weekday afternoon hours, or on weekends and holidays from HE 7 AM to HE 10 PM but not other off-peak hours. Trading in shaped hedges is much less liquid than trading in standard forward hedges. So one could expect shaped hedges to be priced at a premium to expected LMP prices, or, at a higher premium than standard forwards.
- Futures contracts. Futures contracts are purely financial instruments that are not subject to delivery requirements such as day-ahead scheduling with the RTOs. They are otherwise similar to forward contracts except for collateral and margining requirements. Futures contracts generally require both parties to deposit cash with an exchange, and as the contract price moves each day this "margin" is moved between the parties' accounts to reflect their gains and losses. In this way, futures contracts are settled incrementally up to the expiration date (end of the delivery period). Forward contracts

[80] A standard set of holidays is defined by NERC: New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day.

are settled entirely on the expiration date, or monthly if the term is longer than one month. Instead of margin, forward hedges often require parties to post collateral with each other as a guarantee of settlement. Both the NYMEX and the Intercontinental Exchange ("ICE") list futures contracts corresponding to the standard forward hedges described above, at both the PJM Northern Illinois Hub (ComEd) and the MISO Illinois Hub (Ameren).

- Options. 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. A call option, for example, can help hedge against price increases but provides no hedge against price decreases. A price decrease is a risk to the utilities, passed through to their customers, if it is accompanied by increases in municipal aggregation or other forms of switching that leave the utility expensive hedges it no longer needs. Options on forward or futures contracts are much less expensive than the contract themselves, because they only convey the right to spend the money to buy the contract.
- Swing options. A swing option is a forward hedge that gives the buyer the right, but not the obligation to change the volume in some subset of hours. Generally, the buyer can either zero out the volume in hours in which it was previously nonzero (curtail), or increase the volume from zero to the full notional volume (dispatch). A contract can include multiple "swings", that is, multiple points at which the decision can be made. A dispatchable option is essentially the same as a swing option with one swing each hour, and unit-contingent volumes. Swing option contracts are generally customized. An exception is a unit-specific dispatchable contract, which is a standard concept.
- Full requirements hedges. A full-requirements or "tranche" contract covers a fixed fraction of an LSE's load, rather than a fixed volume. For example, a 1% one-month tranche contract is a swap contract under which the selling counterparty receives an amount for each hour in the month equal to a fixed price per MWh multiplied by 1% of the LSE's total supply requirement for that hour (load plus losses), and would pay to the LSE an amount equal to the LMP multiplied by 1% of the LSE's total supply requirement for that hour. All these hourly amounts are netted for the entire month. One hundred such tranche contracts will fully hedge the LSE's energy supply for the month, at a fixed price.

  Full requirements hedge contracts differ significantly from the other examples above. Forward hedges and futures require specification of the notional energy volumes. This makes them convenient for suppliers, who can for example sell a forward contract to achieve a precise effect on their portfolio. For example they can be used to take a short position, flatten the portfolio, reduce overall risk, etc. They are not as convenient for an LSE with a varying and uncertain load, who may wish to have a perfectly hedged portfolio. Forward block hedges cannot perfectly cover a load that is 1,900 MW in HE 10 AM and 2,900 MW in HE 4 PM. And, forward hedges cannot perfectly cover a load at HE 4PM that can be either 2,900 MW or 2,000 MW, depending on the weather. Full requirements hedges are useful in addressing load-related risks. Full requirements hedges can also be used in combination with other standard products in a supply portfolio to reduce, but not completely eliminate price risk.

  Full requirements hedges have been used in other states to provide the utility its entire supply requirement at a known fixed price for a specific term. They are not traded products and had to be specifically defined (standardized) for the purpose, through regulatory processes. Auctions were defined in which the utilities would procure them. Information sharing and multiple workshops were needed to ensure that the auctions would attract significant supplier participation and produce competitive prices.

  Section 6.7.1 includes a summary of other states' experience with full requirements hedges and Section 6.7.2 provides an estimate of the cost premium associated with them.

6.2.2 Suitability of Supply Hedges

Not all of the types of hedges described in Section 6.2.1 are suitable for use in this procurement plan and all may not be readily available in electricity markets. Illinois 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 process must satisfy, and mandates that the results be accepted by the ICC.[81] Among the specific requirements, the procurement administrator must be able to create a market price benchmark for the process; the bidding must be competitive; and the procurement administrator is required to report on bidder behavior. 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 product with liquid markets, a bidder can control its own 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. In its previous procurement plans the IPA has generally restricted its hedging to the use of standard forward hedges in 50 MW increments. 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 Chapter 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 a result, the IPA's authority to procure other products, including shaped forward contracts and option contracts, could end up litigated in this proceeding. For any discussion about authority and policy regarding full requirements purchases, the IPA notes that the markets will likely not be as transparent, which in turn results in challenges for the benchmarking and approval process that are central to the IPA's procurement structure.

Futures contracts at the PJM Northern Illinois Hub and the MISO Illinois Hub are traded in reasonably deep 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 ought to be able to obtain competitive pricing on such contracts if it were to want to incorporate them in its portfolio. However, it may be difficult or impossible to conduct the statutory RFP process for futures contracts; for example, it is unclear how the margin requirements would fit within the current regulatory framework.

Even if the utilities cannot procure futures contracts directly, the IPA does take account of them in the development of its procurement strategy. For example, in the past the Agency has procured forward contracts in 50 MW increments. NYMEX futures are 5 MW contracts. This means that both price discovery and supplier hedging are available for smaller quantities. The Agency should be able to conduct its procurements in smaller units too, such as 25 MW blocks.

6.3 Tools for Managing Surpluses and Portfolio Rebalancing

Chapter 4 illustrated that under its expected and low load scenarios. Ameren will be overhedged and will have forward contracts in excess of expected load for most or all of the 2014-2015 delivery year. ComEd appears not to be overhedged in 2014-2015, but under a low load growth, high switching scenario will be overhedged later in the projection horizon. Furthermore, if the Agency continues to use a "laddering approach" it is quite possible that in future years one or both utilities will find that it over-procured in the early years of the ladder and became overhedged.

[81] 220 ILCS 5/16-111.5(b), (e), (f).

The Illinois Power Agency Act specified that the procurement plan "shall include … the criteria for portfolio re-balancing in the event of significant shifts in load."[82] Such re-balancing may be necessary this year, in the case of Ameren. 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.

1. 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. Since these contracts provide renewable energy (energy plus RECs), curtailing them has reduced ComEd's forward position. Still, this is a small effect compared to the potential re-balancing need, especially for Ameren. Ameren has not previously curtailed renewable contracts but expects to beginning with the 2014-2015 delivery year.
2. For the last few years the utilities have rebalanced their portfolios in the RTOs' day-ahead markets. This has been the dominant mode of portfolio rebalancing. Revenues from the sale of excess energy in the day-ahead market helps to offset the overall cost of the hedges already procured.
3. 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 would have to verify that these kind of events fall within its authority to "conduct competitive procurement processes" under 20 ILCS 3855/1-20(a)(2) and that the utilities whose contracts are to be sold or who would be selling an offsetting position are amenable. The utilities' amenability will probably flow from ICC approval of a procurement plan including such reverse RFPs. Finally the risk associated with the volume to be re-balanced would have to be large enough to justify the expense of a procurement event.
4. Assuming the Agency had the requisite authority, it could also 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 contractual difficulties associated with selling forward hedge contracts, if those contracts are not freely assignable. However, this approach will require the utilities to ensure they had regulatory approval to exercise the options after purchasing them.

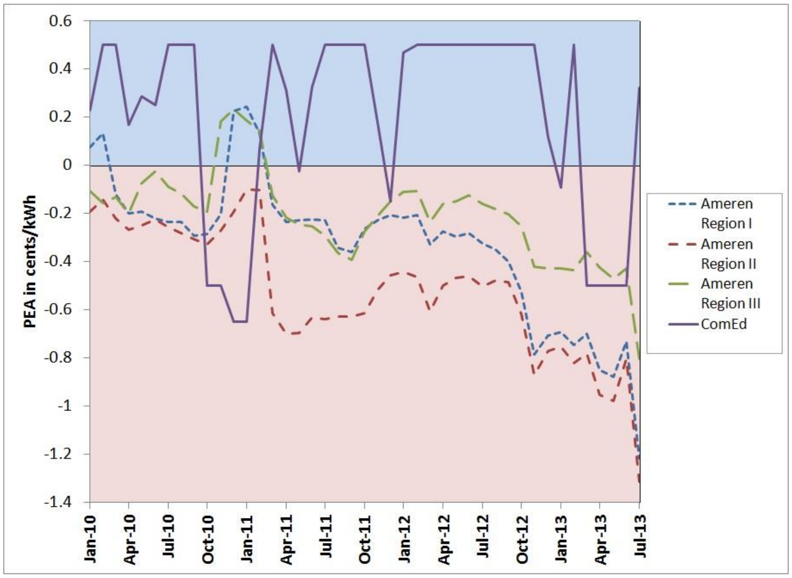
6.4 Comparison to the Purchased Electricity Adjustment

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 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 three years. While Ameren's PEAs have been generally negative, ComEd's have been more often than not positive, but quite volatile. 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 July 2013 the absolute value of Ameren PEAs increased significantly. The IPA understands this decrease to be temporary in nature as Ameren approaches the final months of transitioning to a uniform PEA applicable to all zones, and that the Ameren PEA is likely to return to a smaller adjustment in coming months.

[82] 220 ILCS 5/16-111.5(b)(4).

Figure 6-1 Purchased Energy Adjustments in Cents/kWh



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

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 (the Long-term Renewables Contracts), along with RTO load balancing services to serve load. In other words, energy delivery has been coordinated by the RTOs and the Agency has arranged a portfolio of long-term contracts and standard forward hedges, in multiples of 50 MW, for each utility. Ancillary services have been purchased from the RTO spot markets. The utilities have used Financial Transmission Rights and Auction Revenue Rights to mitigate transmission congestion risk.

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. Procurements have 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 (in 50MW increments) as close as possible to 35% of the monthly average peak and off-peak load forecasts for the 2012-2013 procurement year. In the Spring of 2011, the Agency procured forward hedge volumes (in 50MW increments) 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 procurement year. And in the Spring of 2012, the Agency procured forward hedge volumes (in 50MW increments) 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 procurement 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%. A formal request of the ICC was not made and a decision was deferred as no procurements were held in the plan, a formal request of the ICC was not made and a decision was deferred until future Plans. Under this example, 25% of the 2013-2014 delivery years' expected load would be left unhedged. This would be consistent with a view that over-forecasting would be more costly than under-forecasting, or that forward hedges were priced at a premium to the expected spot price. 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 long-term renewable PPAs) 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 Risk Factors

Section 6.1 enumerated a number of risks in power procurement, some of which have mitigated by the Agency's historic procurement strategy. The IPA used a Monte Carlo model to evaluate the potential cost and uncertainty impacts of various risks. "Uncertainty impact" refers to the fact that uncontrollable changes in variables such as forward and spot prices or customer loads can affect the total cost as well as the cost per MWh of a portfolio. A simple measure of the uncertainty impact is the standard deviation of the distribution of possible cost outcomes. The Monte Carlo model simulates random values of forward and spot costs, and of load growth, weather and switching, and estimates the distribution of cost outcomes. The standard deviation of cost is estimated by the sample standard deviation of the simulation cost distribution. It is quite difficult to estimate the probabilities of price and load scenarios for the next several years, so one must use these results carefully. Strategic choices with a three-year horizon should not be based solely on small differences in simulated outcomes.

The Monte Carlo model is described in Appendix F. The model was run separately for Ameren and ComEd, with different parameters: the Ameren model utilizes the Ameren load forecasts, the MISO Illinois Hub forward price curve and a model of price uncertainty based on historic MISO day-ahead prices; the ComEd model utilizes the ComEd load forecasts, the PJM Northern Illinois Hub forward price curve and an model of price uncertainty based on historic day-ahead prices.

The model ran in two different modes: single year and three-year. The single year mode assumes an existing hedge portfolio from purchases over the previous two years and includes only the hedges acquired for the prompt year, that is, the year beginning on the next June 1. The three-year mode includes the implementation of the chosen hedging strategy.

While the simulation model's parameters are based on statistics drawn from historical price and load distributions, the model was not precisely calibrated. Its results should not be taken as cost forecasts, but as estimates of the cost under different assumptions whose differences can be used as relative indicators of the impacts of various risk factors.

6.5.2.1 Shaping

"Shaping" represents the impact of the correlation of load and price, both of which vary during the period of time hedged by a standard product. In order to determine the impact of the shaping risk factor, the Monte Carlo model was run for each utility for a single year. The forward price was not an important factor, only the forward volume. The assumed granularity or contract size of forward hedges was important. To evaluate shaping, the IPA used a granularity of 0.001 MW (1 kW). This very fine granularity implied that for all practical purposes the model could perfectly hedge the average hourly load in the monthly peak and off-peak periods. The only variability would be due to the difference between average and hourly loads. Load forecast error or variation was suppressed. The runs each assumed the expected load forecast matched actual loads.

The impact of shaping is the difference between the unit (per-MWh) cost of the hedges, and the total unit cost of the hedged portfolio, including hourly energy purchases or sales at spot due to the imperfection of the hedges. The costs are shown in Table 6-1.

Table 6-1 Impact of Shaping

	Ameren	ComEd
Hedge Cost ($/MWh)	$29.63	$29.53
Total Cost ($/MWh)	$31.37	$31.29
Cost Impact of Shaping ($/MWh)	$1.74	$1.76
Cost Impact of Shaping (Relative)	5.9%	6.0%

6.5.2.2 Spot Price Uncertainty

The IPA separately estimated the impacts of forward and spot price uncertainty. The impact of forward price uncertainty depends on the strategy chosen, and is addressed in the following section.

"Spot price uncertainty" means the variation in prices during the delivery month itself, relative to the closing price of the forward contract at the end of the prompt (previous) month. A one-year model was used to consider the impact of spot price uncertainty, assuming no variation or uncertainty in the hedge prices. Similar to shaping, the load forecast error was suppressed and the each run assumed the load would match the expected load forecast.

The representation of spot price uncertainty is explained in Appendix F. The impact of spot price uncertainty is the difference between the total cost in a run with uncertain spot prices, and the total cost in the model runs described in 6.5.2.1 above. The real impact of uncertainty is shown by the sample standard deviation of that difference, as given in Table 6-2.

Table 6-2 Cost Impact of Spot Price Uncertainty

		Ameren	**ComEd**
Total Cost with Spot Price Certainty ($/MWh)	Sample Mean	$31.37	$31.29
Total Cost with Uncertain Spot Prices ($/MWh)	Sample Mean	$31.37	$31.29
	Sample Std. Deviation	$0.09	$0.08
Impact of Spot Price Uncertainty – Std. Deviation ($/MWh)		$0.09	$0.08
Impact of Spot Price Uncertainty– Std. Deviation (Relative)		0.3%	0.3%

By comparing Table 6-2 with Table 6-1, the analysis demonstrates that for the time period examined, spot price uncertainty is a much less significant risk factor than shaping. Not only is it smaller numerically, it also represents a typical variation in prices – positive or negative – rather than an expected change in one direction. A forward price immediately prior to the delivery month generally provides a good forecast of the average spot price for that month.

The IPA's procurement schedule makes it impossible to limit price risk to spot price uncertainty. Uncertainty in this case is the difference between the average monthly spot price and the price of that month's forward price at the end of the previous month. In other words, even though the IPA has historically purchased its forward hedges in April or May for the full year beginning June 1, the estimation of the impact of "spot price uncertainty" ignores variation in the forward price between the purchase date and the beginning of each contract's delivery month. This variation is considered to be part of the forward price risk factor. Also, each month's spot price uncertainty is assumed to be uncorrelated with every other month's spot price. This seems reasonable because it implies medium- to long-term trends would have been detected in the forward market.

6.5.2.3 Forward Price Uncertainty

The representation of forward price uncertainty is explained in Appendix F. The greatest impact of forward price uncertainty will be seen in an "all-spot" portfolio, that is, a portfolio with no forward hedges at all. The spot price is assumed to fluctuate around the forward price as of the beginning of the month; in other word, accumulated variability in the forward price for each month also affects the spot price. On the other hand, if a portfolio includes forward contracts, then from the point those forwards are purchased, that fraction of the portfolio will accumulate no more price variability.

Table 6-3 presents the variability or uncertainty in the average cost of energy over the year for each utility, as represented by its standard deviation. The uncertainty is shown with a one-year look-ahead, in other words, the possible error in a spring forecast of the coming year's energy cost, and with a three-year look-ahead, appropriate to the IPA's historical "laddering" of energy purchases over a three-year horizon. The standard deviation metrics are also presented relative to the expected costs, to account for the cost differences both between regions and between 2014-2015 and 2016-2017 delivery years.

Table 6-3 Cost Impact of Forward Price Uncertainty

Impact of Forward Price Uncertainty (Std. Deviation of All-Spot Cost)	Ameren	ComEd
Over the Upcoming Year (Prompt Year), $/MWh	$6.65	$6.65
Over the Upcoming Year (Prompt Year), Relative	20.3%	20.5%
Over Three Years, $/MWh	$10.48	$10.08
Over Three Years, Relative	28.9%	27.8%

Forward price uncertainty can be mitigated, to some extent, by hedging. The effectiveness of hedging depends on hedge laddering strategy. If load uncertainty is ignored, then the differences among the cost distributions associated with the different strategies should reflect only the impact of forward price uncertainty and the strategies' effectiveness in mitigating it.

The IPA evaluated eight different laddering strategies using a 3-year model. All but three attempted to enter the delivery year 100% hedged. The eight strategies, and their hedging targets, are:

Table 6-4 Laddering Strategies

Strategy	Cumulative Hedge Target		
	Upcoming Year	Upcoming Year + 1	Upcoming Year + 2
Base Case	75%	50%	25%
Base Case with 100% Hedging	100%	50%	25%
Flat Strategy	100%	66%	33%
Back-Loaded	100%	20%	10%
Front-Loaded	100%	90%	80%
No First Year	100%	33%	0%
Spot-Dominant	60%	30%	10%
No Additional Hedges	0%	0%	0%

The "no additional hedges" scenario demonstrates the impact of the current portfolio. It only includes the hedges that the utilities already have in place, which increase the mean cost and reduce the cost variation – significantly so in the case of ComEd.

Again the IPA simulated strategies with a 0.001 MW granularity in forward contracts, and assumed that the expected load forecast would be achieved. Table 6-5 shows the different strategies' effectiveness in mitigating forward price uncertainty, which is represented by the standard deviation of supply cost in $/MWh relative to the expected cost forecast. The "All-spot" strategy is included as a basis for comparison.

Table 6-5 Impact of Forward Price Uncertainty Under Various 3-year Strategies

Strategy	Ameren	ComEd
Base Case	16.8%	10.9%
Base Case with 100% Hedging	16.4%	10.9%
Flat strategy	14.5%	9.9%
Back loaded	19.8%	13.2%
Front-loaded	9.8%	6.6%
No First Year	20.1%	13.5%
Spot-dominant	19.7%	12.9%
No Additional Hedges	24.9%	15.8%
All-spot	28.3%	27.8%

This price forecast was made on August 1, 2013 and it envisioned forward purchases April 15. The forecast is still exposed to some uncertainty in pricing, namely the uncertain price changes until April 15. But, the hedging strategies all reduce risk relative to full reliance on the spot market, as shown by the difference between their standard deviations and that of an "All-spot" strategy.

The "no additional hedges" scenario in Table 6-5 demonstrates the impact of the current portfolio. It only includes the hedges that the utilities already have in place for 2016-2017. Ameren has only the long-term renewable PPAs. ComEd's portfolio for that year includes 450 MW of RSP contracts. Table 6-5 indicates that there is significant benefit, in terms of price certainty, to additional hedging.

For both utilities, it appears to be most effective to put hedges in place quickly (the Front-loaded strategies). Leaving some load unhedged, as in the Spot-dominant strategy, adversely affects pricing certainty. The same effect is seen by comparing the Base Case strategy to the Base Case with 100% Hedging for Ameren. But it is quite muted since the additional hedging occurs in the last year, after much of the random evolution of forward prices has already occurred. Note however that the purpose of leaving some load unhedged is to hedge against load uncertainty, which was recognized in these simulations but will be addressed in section 6.5.2.4.

Figure 6-1 and Figure 6-2 illustrate the simulated probability distributions (frequency distributions) of the cost of a hedged strategy and compare with the costs of All-spot procurement. The out-of-market (higher priced than the forward curve) legacy hedges make the all-spot strategy less costly. But what are important to note is its greater risk and uncertainty (wider distribution, flatter peak) and higher maximum cost despite its lower average cost (the effect is particularly pronounced in Figure 6-3). That risk is the impact of forward price uncertainty. The hedged distributions are shifted to the right. Again this is more pronounced in Figure 6-3, which shows that hedging can serve to increase costs. In this case because the hedges that are already in place are now out-of-market.

Figure 6-2 Impact of Forward Price Uncertainty Seen in the Frequency Distribution of Costs of Hedged and Unhedged Strategies, Ameren

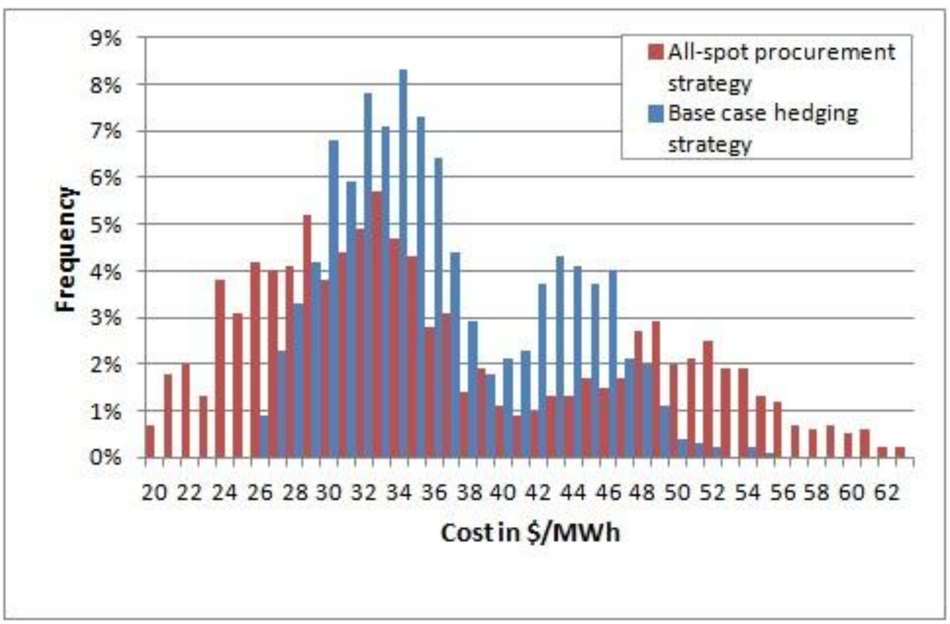
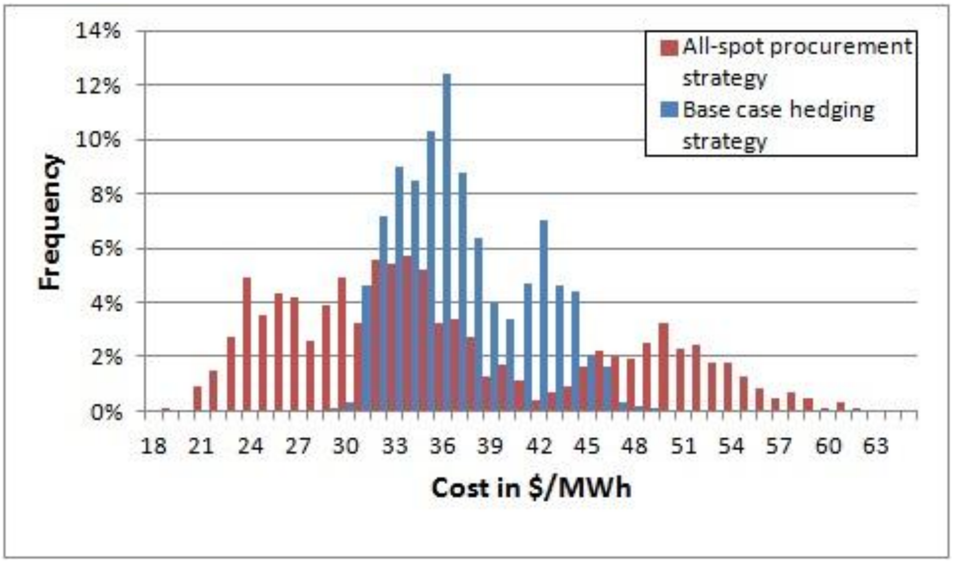


Figure 6-3 Impact of Forward Price Uncertainty Seen in the Frequency Distribution of Costs of Hedged and Unhedged Strategies, ComEd



6.5.2.4 Load Uncertainty

As described in Appendix F, the three load scenarios provided by each utility are used as proxies for load uncertainty. In a simulation of load uncertainty, the three scenarios are modeled as occurring with specific probability weights, such as 20% for a low or high scenario and 60% for an expected scenario.[83] In addition, the simulation assumes that the "actual" load scenario is revealed gradually. That is, the forward strategy is implemented assuming each year that the load will be somewhere between the expected scenario and the simulated actual load.

The metrics in Table 6-6 reflect the impact of load uncertainty. It compares the results from using the base (75/50/25) strategy in the presence of load uncertainty, to the results from Table 6-5 in Section 6.5.2.3. The Monte Carlo model, discussed in Section 6.5.2.3, was modified to use the expected load forecast in every iteration.

Table 6-6 Impact of Load Uncertainty as Seen in the Total Cost of the Base Strategies

Scenario	Statistic of Total Cost in $/MWh	Ameren	ComEd
Load Always Equals Expected Forecast	Sample Mean	$36.44	$37.13
	Relative Std. Deviation	16.8%	10.9%
With Load Uncertainty	Sample Mean	$38.02	$38.09
	Relative Std. Deviation	18.2%	11.8%
Impact of Load Uncertainty	**Relative Increase in Expected Cost**	4.3%	2.6%
	Relative Std. Deviation of Cost Difference	20.2%	12.6%

The last row in Table 6-6 is the standard deviation of the difference in cost with and without load uncertainty (with identical draws for the other random variables in the simulation), relative to the mean cost including load uncertainty. Load uncertainty is more significant with the Ameren forecast, probably because Ameren's

[83] 20% and 60% are purely illustrative values. The computation of the probability weights is described in the last paragraph of Section 3.5.2, and note 70.

high and low load scenarios are more extreme. But in either case it is clear that load variability increases cost risk both in the sense of absolute cost and of uncertainty.

6.5.2.5 Comparison of Hedging Strategies

As a guide to the selection of a hedging strategy, the IPA simulated the effects of multiple hedging strategies, described in Section 6.5.2.3, including all uncertainties. These simulations also assumed that the IPA would hedge in multiples of 25 MW; slightly more granular than the 50 MW hedges it has historically used. The results of this analysis are in Figure 6-4 and Figure 6-5. There is one figure for each utility illustrating the range of possible cost outcomes, as a two-headed arrow from the 10th percentile to the 90th. The horizontal lines indicated the expected cost. The widths are quite similar, and for Ameren they are very significant.

The IPA also simulated an all-spot strategy. Under this strategy, the IPA and utilities would not use any hedges. For ComEd, this strategy appears almost twice as risky as the hedged strategies, as represented by the wider cost distribution. All-spot is also riskier for Ameren than any of the hedging strategies although the difference is less. Note also that the costs of hedging strategies are slightly understated for this comparison, because they include only commodity costs and not transaction costs or the administrative costs of IPA procurements.

Based on these graphs the front-loaded strategy appears the least risky. It is quite an aggressive hedging strategy, though, and it may be premature to make such a switch until there is a better understanding of switching behavior. The flat, base case and base case with 100% hedging strategies all appear to have similar risk-cost properties.

Figure 6-4 Range of Costs for 2016-2017 Under Different Hedging Strategies, Ameren

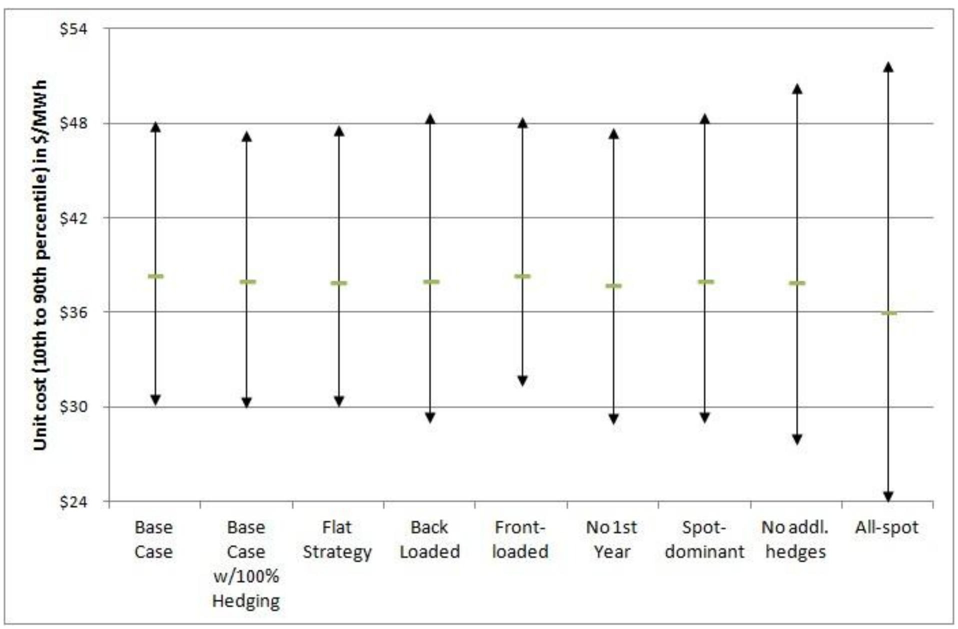
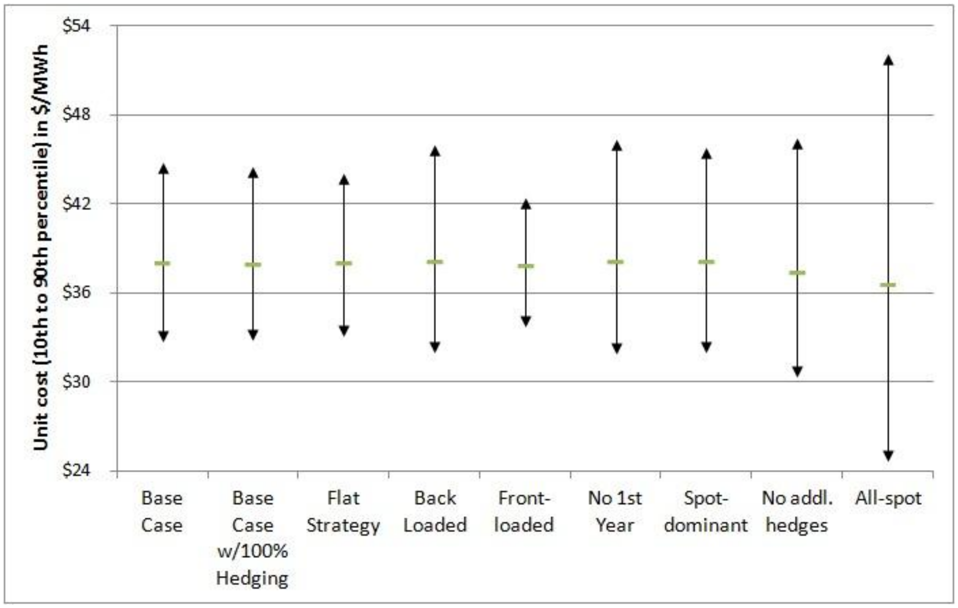


Figure 6-5 Range of Costs for 2016-2017 Under Different Hedging Strategies, ComEd



6.6 Prompt-Year Concerns

There are a couple of issues specific to the first Plan year (the year for which this Plan represents the last opportunity to implement strategy), namely to address shaping risk and reduce value at risk (VAR) associated with Ameren's out-of-market open long position.

6.6.1 Addressing Shaping Risk

According to Table 6-1, the load shape and its correlation with prices adds about 6% to the average cost of supplying energy to retail customers. In other words, if the total load is 500 MWh, and the average hourly power price is $20/MWh, the product of load and average price is $10,000 but the actual cost of energy to serve load will be $10,600. A 500 MWh hedge will cost $10,000. If the average price rises to $30/MWh, the value of the hedge will rise to $15,000, a $5,000 increase. But the actual cost to serve load will rise to $15,900 – an increase of $5,900 of which $900 is unhedged. To actually hedge costs, one would have to buy 530 MWh of hedges – 106% of load. Note that this would not really be a perfect hedge, as not all hourly prices move in proportion to the average.

On the other hand, being "fully hedged" increases the exposure to load risk, and specifically to the risk that load reduction will be coupled with a fall in prices. The load decrease leads to overhedging (some hedges are not offsetting energy purchases to meet load), while the price decrease creates a loss on the hedge portfolio. A reasonable tradeoff would be to complete the hedge later, when there is more certainty about load. At least the short-term fluctuations in pricing will be hedged.

The three-year model used to create Figure 6-4 and Figure 6-5 does not really provide good guidance on strategy for 2014-2015. The great amount of change possible in macroeconomic and local market conditions over the next two years may overshadow the value of purchasing hedges in April for the following June-May. The IPA used additional simulations, limited to the delivery year 2014-2015.

The IPA simulated the four strategies shown in Table 6-7. Note that the model also simulates what the load forecast would be in April 2014 and in September 2014 for the "105/75" strategy. The "105/75" illustrates overhedging to account for shaping costs; it is based on a 105% hedge rather than 106% simply because it is a "rounder" figure.

Table 6-7 Prompt-Year Strategies Tested

Strategy	Description
50% Hedged	Purchase 25 MW forward contracts on April 15 to get the forward peak and off-peak positions for each month as close as possible to 50% of the forecast, without going over*
75% Hedged	Purchase 25 MW forward contracts on April 15 to get the forward peak and off-peak positions for each month as close as possible to 75% of the forecast, without going over*
100% Hedged	Purchase 25 MW forward contracts on April 15 to get the forward peak and off-peak positions for each month as close as possible to 100% of the forecast, without going over*
105%/75% Hedged	Purchase 25 MW forward contracts on April 15 to get the forward peak and off-peak positions for June-October as close as possible to 105% of the forecast, and the positions for November-May as close as possible to 75%, without going over. Purchase additional 25 MW forward contracts on September 15 to get the forward peak and off-peak positions for November-May as close as possible to 105% of the then-current forecast, without going over*

* If a hedge position is already over the target, no purchases are made for that month and period, but excess hedges are not sold.

Figure 6-6 and Figure 6-7 illustrate the range of simulated costs for these hedging strategies. They are similar to Figure 6-4 and Figure 6-5, showing the range of possible cost outcomes for each strategy as a two-headed arrow from the 10th percentile to the 90th, with a horizontal line indicating the expected cost. Because it can be difficult to visually distinguish the price levels, the arrowheads and mean lines are labeled with the corresponding cost values.

Figure 6-6 Range of Costs for Prompt-Year Hedging Strategies, Ameren

Figure 6-7 Range of Costs for Prompt-Year Hedging Strategies, ComEd

Based on Figure 6-6, the four hedging strategies are quite similar for Ameren. The reason is that based on either its expected load forecast or its high load scenario, Ameren is already overhedged for 2014-2015 (see for example Figure 4-2) and would be making almost no purchases under any of the hedging strategies. The same holds for the high load scenario.

Figure 6-7 indicates that the "fully hedged" strategy (105/75) reduces ComEd's price risk: the 90th percentile Value at Risk (difference between 90th percentile and mean) decreases by about $0.26/MWh, or 0.026 cents/kWh, relative to the 75%/50%/25% strategy. This is not a large amount per customer: according to data in the 2012 EIA form 826 database, a typical Commonwealth Edison customer uses about 700 kWh/month so the VAR represents about 18 cents/month on a typical bill of $84 – small but not insignificant. But over the expected load forecast as a whole, the VAR reduction is $2.92 million.

The caution against making decisions based on small differences between scenarios, found in the introductory paragraph of Section 6.5.2, is not as applicable to prompt-year strategy as to three-year strategy. Purchases in April 2014 will have the benefit of a much reduced level of uncertainty in switching estimates for the delivery year, and of greater confidence in the general trend of market prices. In general, therefore, there is less potential for error in the estimation of probability distributions.

6.6.2 Hedge Rebalancing Through Sales

The previous section referred to Figure 4-2 as showing Ameren's currently over hedged position for 2014-2015. Table 7-4 in Chapter 7 demonstrates in greater detail that Ameren will be over hedged in each month from September 2014 through May 2015, even relative to 106% of the expected load.

The "fully hedged" (105/75) strategy includes two possible procurement events, in April and September. Expanding those events to include the sale as well as purchase of 25 MW contracts, if load forecasts made for those events are sufficiently low, would reduce the value at risk from loss of load. Figure 6-8 is a revision of Figure 6-6 to include a version of the 105/75 strategy in which sales is allowed. There is a very slight improvement in expected cost but it appears that this strategy has the lowest risk of unexpected cost increases. Along with the $0.06/MWh reduction in the expected cost, the 90th percentile VAR improves by $0.30/MWh relative to the 105/75 strategy with no sales. In an actual sale, the improvement may be reduced significantly, due to the cost of selling and the bid-ask spread (the model ignores the cost of selling and assumes sales at the mid-mark, that is the average of the bid and the ask prices, while buyers may only offer the bid price or less).

Figure 6-8 Range of Costs for Prompt-Year Hedging Strategies (Including Forward Rebalancing Strategy), Ameren

6.7 The Risks of Spot Markets and Full Requirements Supply

The current supply portfolios of Ameren and ComEd, by chosen strategy/portfolio design, do not perfectly hedge their load, primarily due to load uncertainty, the mismatch of demand and hedge profiles, and the correlation between price and load, as explained in Section 6.1.2.7. Currently the utilities' supply customers absorb the residual risk resulting from the utilities' portfolio design. In other words, customers self-insure the residual risk. The effect of this risk becomes apparent in the application of the PEA discussed above. (ComEd mitigates this impact by voluntarily limiting the PEA to ±0.5 cents per kWh each month.) On the other hand, if the goal of the supply strategy/portfolio design were to provide customers power at a fixed flat price over a multi-month period (one to three years) similar to ARES products offered directly or through municipal aggregation, a full requirements product may be a reasonable alternative. Full requirements contracts provide a form of insurance by outsourcing supply risk to a third party. Full requirements solicitations are used in several jurisdictions as a source of supply for "default service" load. There are several different justifications brought forth for the use of full requirements procurement:

- Full requirements procurement provides customers price insurance. One function of a competitive retail supplier is to provide price certainty. This justification presumes a policy choice that the default provider should take on that role. An alternative policy choice is to have price insurance be provided only to ARES customers, by ARES. The policy choice should also be informed by a judgment of a reasonable level of the insurance premium, as some customers may prefer to forego such insurance. This Section provides some guidance into the price premium one can expect to pay for such insurance, as well as the effectiveness of that insurance in removing price uncertainty, to facilitate discussion and form an opinion as to whether customers would perceive the insurance as valuable enough to justify the premium. The estimates in this Section are only illustrative and are compared with estimates of the level of uncertainty in prices.
- Full requirements supply more appropriately represents the Price to Compare, since it includes a valuation of the uncertainty in actual pricing. Again, one must determine whether the improvement is worth the premium.
- Full requirements pricing avoids the potential for utilities to accumulate high balances (credit or debit) to be amortized by Purchased Energy Adjustments. These balances when they have been a debit have been most significant for ComEd. Because ComEd voluntarily limits the size of the monthly PEA to plus or minus half a cent per kilowatt-hour, it is susceptible to accumulate large uncollected balances. The uncollected balances are arguably a form of price insurance that is

voluntarily underwritten (without a carrying charge) by the utility. The choice to buy full requirements should not depend on the absolute magnitude of that price premium but rather on whether that price premium is comparable to the value that consumers would perceive they obtain by mitigating the uncertainty around the price. That uncertainty is represented by the width of the price distributions in Section 6.5. One of those distributions represents an all-spot portfolio, the opposite end of the spectrum from full requirements. There is no obvious formula for converting the statistics of the cost distributions into dollar measures of value. That depends entirely on customers' risk preferences. Presumably, an informed utility supply customer who values price certainty would choose to take service from an ARES who offers a fixed price directly or through a comparable municipal aggregation plan.

- In any assessment of full requirements strategies compared to past IPA procurements, the IPA notes that through June 2013, Ameren and ComEd's portfolios partially consisted of out of the market swap contracts, (entered into per the 2007 settlement as memorialized in Section 16-111.5(k) of the PUA[84]). In contrast, the supply currently under contract in the utility portfolios (which does not properly hedge the upcoming delivery years and thus must be supplemented per this Plan) is mostly of more recent vintage and is closer to market prices. Any plan to fully or partially implement full requirements procurement would have to address the effect and treatment of the current contract positions in the utilities' supply portfolios.

6.7.1 Experience in Other Jurisdictions

In 2006, Ameren and ComEd conducted a solicitation for full requirements contracts using a "descending clock" auction. The full requirements bids that cleared the auction had higher prices than many stakeholders and policymakers expected, and significantly increased retail rates.[85] State policymakers decided that those prices did not adequately reflect customers' risk preferences. Given Illinois' history, as part of considering procurement of full requirements products, it is reasonable to consider whether they have been successful elsewhere.

Since August 2002, New Jersey utilities have supplied the "default" electric load of residential and small commercial customers using full requirements tranche contracts. "Default" load means the load of customers who have not switched to non-utility suppliers, what is called "eligible retail load" in Illinois. The contracts are procured using an annual "descending clock" auction, held the previous February. The tranche auctions are used to procure a ladder of 3-year fixed price contracts. The tariffed power price is the average of the prices of the three contracts that overlap a given year. The New Jersey auctions are well established and appear successful.

[84] *See* 220 ILCS 5/16-111.5(k).

[85] The IPA does not wish to fully detail the story of the 2006 auction and subsequent legal and political action; suffice to say that policymakers decided the results were unacceptable and adopted a number of legislative solutions including the formation of the IPA.

Figure 6-9 Price History for PSEG Full Requirements Contracts

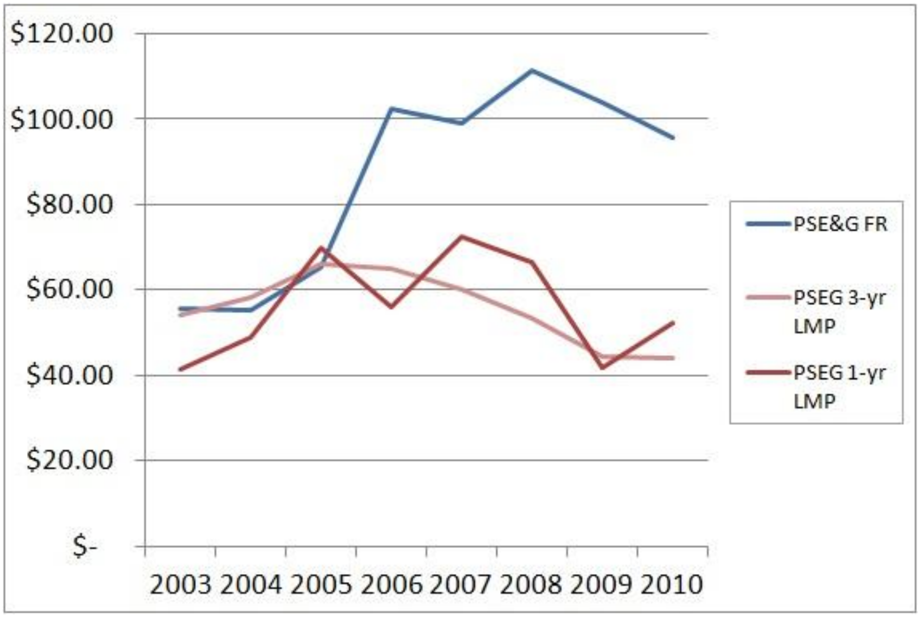


Figure 6-9 shows the pricing that one of the New Jersey utilities has obtained from the auction for 3-year full-requirements contracts. It also shows the pricing of a "spot strip", that is, the average spot price in the PSEG load zone over the same period (not a load-weighted average; the above shaping analysis indicates load-weighting would increase the average by about 6%). The figure shows that, beginning in 2006, full-requirements prices have been well above the average spot price. The third line in that figure displays the average spot price over just the first year of the full-requirements contracts. While it is quite likely that a significant amount of the increase in full requirements prices relative to realized LMPs may be due to changes in forward markets, suppliers still appear to have recalibrated their own views of full requirements risk beginning in 2006.

Utilities in Maryland, Delaware, and the District of Columbia have used a similar approach for purchasing electricity supply on behalf of their Standard Offer Service customers, for the last seven years. They have separate procurements for full requirements tranche contracts, and have employed several laddering schemes and combinations of contract terms over that time. State and District regulators oversee the auctions. Maryland has formalized a process by which a procurement monitor determines in advance a "Price Anomaly Threshold" used to eliminate bids from consideration. The operation of the Price Anomaly Threshold could result in utility demand being unfilled, so a series of auctions are scheduled to meet residual need.

Utilities in Massachusetts and Rhode Island also procure full requirements contracts for their default service via an RFP process.

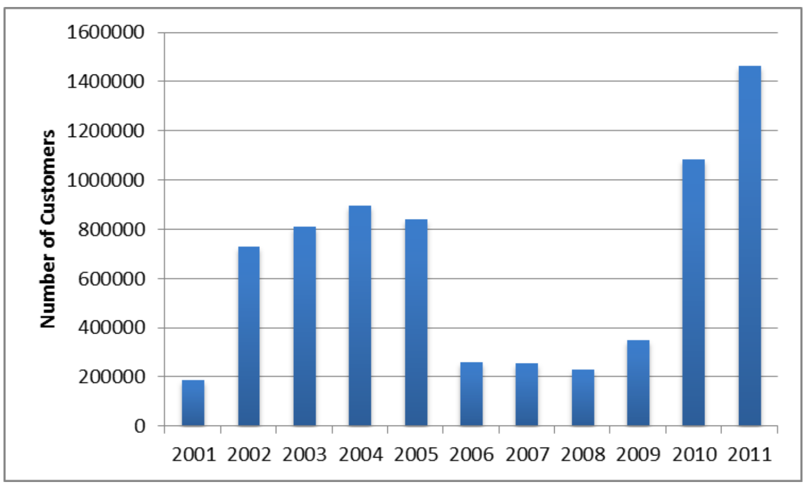
Ohio presents a case with some relevance to Illinois. Ohio deregulated its electricity market in 2001, opening its door to competitive electric suppliers. Significant customer switching occurred in FirstEnergy's territory, primarily through municipal aggregation, during the early years of the deregulation (see Figure 6-10). By December 2004, residential switching was 69% in Cleveland Electric's service area and 48% in Toledo Edison's service area. However, switching was very limited in AEP's and DP&L's service areas, where electricity prices were low relative to those in FirstEnergy's territory. The number of competitive electric suppliers, as well as the market activity, remained pretty limited statewide. Much of the switching came through municipal aggregation.

The State was supposed to transition in 2006 to rates reflective of contemporaneous energy market prices, but Ohio's Public Utility Commission ("PUCO") was concerned that an immediate shift to market based rates would expose customers to rate hikes. Therefore, the PUCO developed rate stabilization plans ("RSPs") in order to hedge Ohio's customers against market uncertainty. The RSPs had the effect of holding electricity prices below market levels for several years, from 2006 to the end of 2008 for most Ohio customers. In this context, FirstEnergy conducted a "reverse auction" procurement of full requirements tranche products to verify if rates lower than those agreed in the RSPs could be obtained. The PUCO's consultant estimated a 100% probability that the RSP rates would be cheaper. Therefore, the PUCO rejected the results of the auction.

The implementation of the RSPs resulted in customers switching back to the utilities services as competitive providers could not beat or even match the utilities' pricing. In December 2006, residential switching was only 8% in Cleveland Electric's service area and 11% in Toledo Edison's service area, down from 69% and 48% two years earlier. This demonstrates that customers will return to utility service when they perceive a price advantage in doing so.

With the expiration of the RSPs in 2009, utility prices became less attractive relative to those of alternative suppliers. This had the predictable effect of significantly increasing customer switching, as demonstrated in Figure 6-10. Customer switching levels are currently greater than the peaks observed in 2004. This emphasizes the need for a sound energy procurement strategy from the utilities. The three First Energy utilities did begin soliciting full requirements products and have successfully used them to supply their non-switching customers.

Figure 6-10 Number of Ohio Customers Switching to Competitive Providers[86]



Utilities in other states have successfully used full requirements contracts to meet retail load. The example of Ohio even shows that a regulator and the public can become comfortable with obtaining full requirements supply through auction after having initially rejected the concept. Figure 6-10 shows that customers will respond to their perceptions of the difference between utility bundled service and alternative suppliers (whether the utility supply comes from full-requirements contracts or a portfolio of block contracts). However, the price history in New Jersey provides a cautionary example that full-requirements pricing can change abruptly with suppliers' perceptions of risk.

It should be noted that the full requirements contracts described above are different from full requirements energy hedges. The products discussed above include ancillary services and capacity as well as transmission to the load center. A full requirements energy hedge, on the other hand, protects the utilities' customers only from exposure to the volatility of RTO spot energy prices but does not include ancillary services or capacity.

[86] Source: EIA Form 861.

6.7.2 Cost and Risk of Full Requirements Contracting

The price of a full-requirements energy hedge should be based on the cost and risk incurred by a provider of that hedge. To investigate that, and in particular to see how that price compared to the costs of other procurement strategies, and the value of risk avoidance, the IPA simulated the development of a full requirements portfolio using its Monte Carlo model. The simulation was almost identical to the simulation of the various hedge portfolios in Section 6.5.2.5. The IPA simulated full-requirements contracts of two different durations:

- A one-year contract, in which the hedge would be effective from June to May under a price that was set six weeks before delivery began (in mid-April). The IPA simulated hedging to 50%, 75% and 100% of the expected load forecast, as well as a totally unhedged position (all-spot).
- The third year of a three-year contract, so that the hedge supplier could have been laddering its own hedge portfolio for three years. The IPA simulated the hedge laddering strategies summarized in Table 6-4, as well as a totally unhedged position (all-spot). The only real difference between this simulation and the simulations in Section 6.5.2.5 is that the full requirements supplier is assumed to start from scratch, with no existing hedge portfolio, and that it is assumed to hedge itself with 5 MW fixed-price contracts (representing futures).

The IPA went on to estimate the price of a full-requirements hedge. Essentially that means the IPA had to estimate the premium that would be charged to insure against the identified price uncertainty. Some suppliers might be able to provide such insurance from an offsetting position – for example, a supplier with a number of municipal aggregation contracts may have a position that offsets the utility's switching risk. In general, though, one cannot assume such an offsetting position.

IPA employed a heuristic approach to develop illustrative premiums. IPA assumed that a supplier would hold capital to cover a prescribed level of risk. It is assumed the hedge provider holds working capital equal to its "95th percentile VAR", which equals the amount by the 95th percentile of the unit cost distribution exceeds the expected unit cost.[87] The supplier must pay a return on that capital, and that return is an estimate of the required insurance premium. As this is a preliminary estimate, used to inform the Agency and the ICC of the approximate cost of full requirements hedges, the return assumption for the third year of a three-year contract is 30% (about 10% per annum).

The 10% figure is an approximate level of return. Illinois utilities' rate of return on equity for participating electric utilities (as defined under the Energy Infrastructure Modernization Act) is set at a one-year average the monthly 30-year Treasury bill rate, which for the year ending July 31, 2013 was 3.06%[88] plus 580 basis points. That would imply a rate of just under 9% per annum. However, an investment in a deregulated full-requirements provider is considerably more risky than one in a regulated distributed utility, and furthermore rates are expected to rise; therefore the Agency used the round figure of 10% for its analysis.

Therefore, the cost of any strategy to supply the third year of a full requirements contract is:

$$\text{Mean unit cost} + 0.30 * 95^{th} \text{ percentile VAR}$$

For a 1-year full requirements contract the formula would be similar but with 10% rather than 30%.

The estimated market price of a full requirements contract is the minimum supply cost over all strategies. The full-requirements supplier would be expected to choose the least expensive supply strategy. In other words, it is estimated that the full-requirements supplier's cost (including its risk premium) would be the lowest "supply cost" over all tested strategies. The IPA's goal in designing a full requirements procurement would be to allow suppliers as little additional profit as possible over the risk premium, and therefore it is

[87] The 95th percentile cost is the value V such that the probability that the unit cost is less than or equal to V equals 0.95.
[88] 220 ILCS 5/16-108.5(c)(3); rates are computed from http://www.federalreserve.gov/datadownload/Output.aspx?rel=H15&series=42ebb0d7e12040e88e235393ae1148e6&lastObs=&from=&to=&filetype=csv&label=include&layout=seriescolumn.

appropriate to use the minimum supplier cost as a forecast of the full requirements hedge price. The results of the simulation are presented in the following subsections.

This estimate of full requirements market price should not be compared directly with the range of supply costs for strategies not involving full requirements supply, such as are displayed in Section 6.5.2.5. It is an estimate of the cost of serving full requirements load assuming the load was fully unhedged as of the date of the forecast. To properly compare it with the projected cost of the IPA's procurement strategy, the loss (or gain) that will be realized from the utilities' current portfolios of hedge contracts must be added. The relevant statistics of those losses or gains (per MWh) are in Table 6-10 and Table 6-13.

6.7.2.1 Estimated Cost of Full Requirements Supply for Ameren

Table 6-8 Full Requirements Supply Costs for a 1-Year Contract, Ameren (Without Existing Hedges)

Strategy	Cost ($/MWh)			$/MWh
	Mean	Standard Deviation	95th Percentile	Supply Cost
100% Hedged Each Month	$ 32.68	$ 5.84	$ 42.32	$ 33.64
75% Hedged Each Month	$ 32.69	$ 6.04	$ 43.09	$ 33.73
50% Hedged Each Month	$ 32.70	$ 6.27	$ 43.67	$ 33.80
All-Spot	$ 32.72	$ 6.82	$ 44.78	$ 33.93
Estimated Cost of a Full-Requirements Hedge (Cost of Least Expensive Supply Strategy)				$ 33.64

Table 6-9 Full Requirements Supply Costs for the Third Year of a 3-year Contract, Ameren (Without Existing Hedges)

Strategy	Cost ($/MWh)			$/MWh
	Mean	Standard Deviation	95th Percentile	Supply Cost
Base Strategy	$ 36.25	$ 6.57	$ 48.16	$ 39.82
Base Case with 100% Hedging	$ 36.22	$ 6.12	$ 47.02	$ 39.46
Flat Strategy	$ 36.23	$ 7.90	$ 50.59	$ 40.54
Back Loaded	$ 36.13	$ 6.60	$ 47.90	$ 39.66
Front Loaded	$ 36.22	$ 8.08	$ 50.77	$ 40.58
No First Year	$ 36.23	$ 7.77	$ 50.37	$ 40.47
Spot-Dominant	$ 36.24	$ 6.50	$ 48.04	$ 39.78
All-Spot	$ 36.16	$ 10.04	$ 54.29	$ 41.60
Estimated Cost of a Full-Requirements Hedge (Cost of Least Expensive Supply Strategy)				$ 39.46

Table 6-10 Potential Loss / (Gain) on Current Ameren Hedge Portfolio

Delivery Year	(Gain) / Loss ($/MWh)		
	Expected Loss	10th Percentile	90th Percentile
2014-2015	$3.69	($6.74)	$13.74
2016-2017	$1.92	($1.08)	$8.18

Figure 6-11 compares the cost of full requirements contracts for 2016-2017, including hedging gains or losses, with the Ameren hedging strategies shown in Figure 6-4. Like that figure, it shows the expected $/MWh cost of each along with 10th and 90th percentiles. The full requirements strategy appears to have a definite cost premium, although it does eliminate much of the uncertainty in customer costs. (The expected cost in Figure 6-11 includes both the full requirements hedge cost from Table 6-9 and the expected hedging loss from Table 6-10.) It also remains to be seen whether bidders will be willing to bid the prices estimated above.

On the other hand, Figure 6-12 considers the cost of full-requirements contracts for Ameren's 2014-2015 delivery year. It compares them with three hedging strategies: (1) no additional hedges beyond the utilities' current portfolio; (2) conducting a hedge procurement in April, 2014, aimed at hedging up to 75% of the then-forecast load; (3) conducting a hedge procurement in April, 2014, aimed at hedging all the then-forecast load. In this case the full-requirements contract, with the assumptions above about pricing, contributes to retail delivery at a much smaller premium, but with a very great range of uncertainty (from the "grandfathered" hedge losses).

Figure 6-11 Full Requirements Strategy (including existing hedging gains or losses) compared with Conventional Hedging Strategies for 2016-2017, Ameren

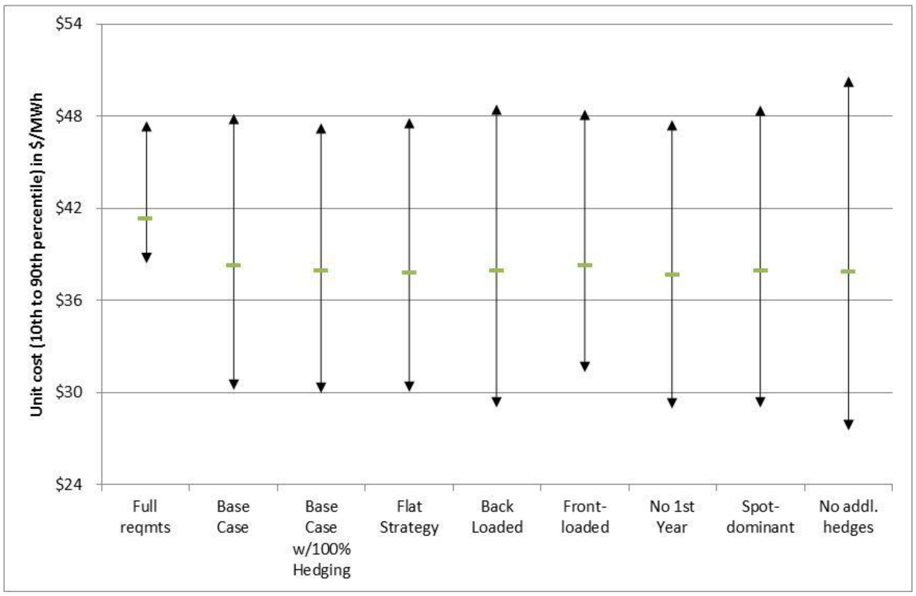


Figure 6-12 Full Requirements Strategy (Including Existing Hedging Gains or Losses) Compared with Conventional Hedging Strategies for 2014-2015, Ameren

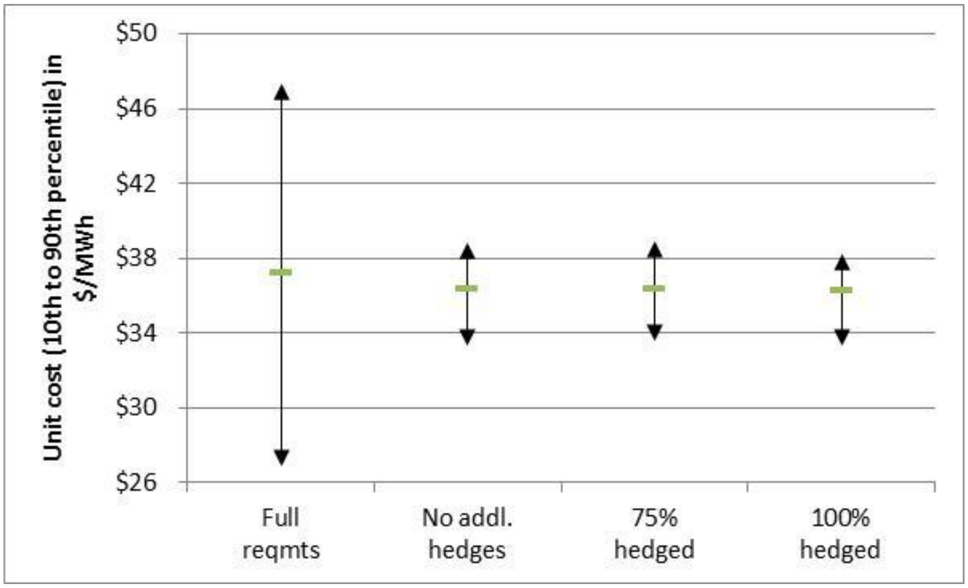


Figure 6-11 and Figure 6-12 indicated an uncertainty band around the cost of full requirements supply, despite the fact that it is an insurance product. That is because this is the cost to customers, who would have to bear the losses (or gains) of the current hedge portfolio. IPA also simulated the price of full requirements supply assuming that the financial impacts of the existing contracts (or the contracts themselves) were allocated to full requirements suppliers pro rata.[89] The cost to customers turned out to be about the same as the expected cost under the first analysis, but with no variability.

6.7.2.2 Estimated Cost of Full Requirements Supply, for ComEd

Table 6-11 Full Requirements Supply Costs for a 1-Year Contract, ComEd (Without Existing Hedges)

Strategy	Cost ($/MWh)			$/MWh
	Mean	Standard Deviation	95th Percentile	Supply Cost
100% Hedged Each Month	$ 32.58	$ 5.78	$ 42.42	$ 33.57
75% Hedged Each Month	$ 32.58	$ 5.95	$ 42.77	$ 33.60
50% Hedged Each Month	$ 32.58	$ 6.14	$ 43.15	$ 33.64
All-Spot	$ 32.58	$ 6.60	$ 43.77	$ 33.70
Estimated Cost of a Full-Requirements Hedge (Cost of Least Expensive Supply Strategy)				$ 33.57

[89] This type of allocation may not be possible. The contracts themselves may not be allocable, and if the utilities were to retain the contracts but not the associated load obligation there could be adverse accounting implications.

Table 6-12 Full Requirements Supply Costs for the Third Year of a 3-Year Contract, ComEd (Without Existing Hedges)

Strategy	Cost ($/MWh)			$/MWh
	Mean	Standard Deviation	95th Percentile	Supply cost
Base Strategy	$ 35.62	$ 1.75	$ 38.56	$ 39.71
Base Case with 100% Hedging	$ 35.62	$ 1.93	$ 38.89	$ 38.80
Flat Strategy	$ 35.62	$ 1.96	$ 38.87	$ 39.84
Back Loaded	$ 35.62	$ 1.91	$ 38.82	$ 37.75
Front Loaded	$ 35.62	$ 1.90	$ 38.77	$ 39.89
No First Year	$ 35.62	$ 2.00	$ 38.94	$ 39.77
Spot-dominant	$ 35.62	$ 1.65	$ 38.37	$ 39.09
All-spot	$ 35.61	$ 1.93	$ 38.81	$ 40.72
Estimated Cost of a Full-Requirements Hedge (Cost of Least Expensive Supply Strategy)				$ 37.75

Table 6-13 Potential Loss / (Gain) on Current ComEd Hedge Portfolio

	(Gain) / Loss ($/MWh)		
Delivery Year	Expected Loss	10th Percentile	90th Percentile
2014-2015	$2.19	($1.32)	$6.01
2016-2017	$1.86	($4.52)	$7.79

Figure 6-13 compares the cost of full requirements energy contracts for 2016-2017, including hedging gains or losses, with the ComEd hedging strategies shown in Figure 6-5. Like that figure, it shows the expected $/MWh cost of each along with 10th and 90th percentiles. The full requirements strategy again has a price premium over the traditional hedging strategy, and comparable price risk. (The expected cost in Figure 6-13 includes both the full requirements hedge cost from Table 6-12 and the expected hedging loss from Table 6-13.)

Figure 6-14 considers the cost of full-requirements energy contracts for ComEd's 2014-2015 delivery year. It compares them with three hedging strategies: (1) no additional hedges beyond the utilities' current portfolio; (2) conducting a hedge procurement in April, 2014, aimed at hedging up to 75% of the then-forecast load; (3) conducting a hedge procurement in April, 2014, aimed at hedging all the then-forecast load. In this case, the full-requirements energy contract does reduce ratepayer risk, but again at a price premium.

Figure 6-13 Full Requirements Strategy (Including Hedging Gains or Losses) Compared with Conventional Hedging Strategies for 2016-2017, ComEd

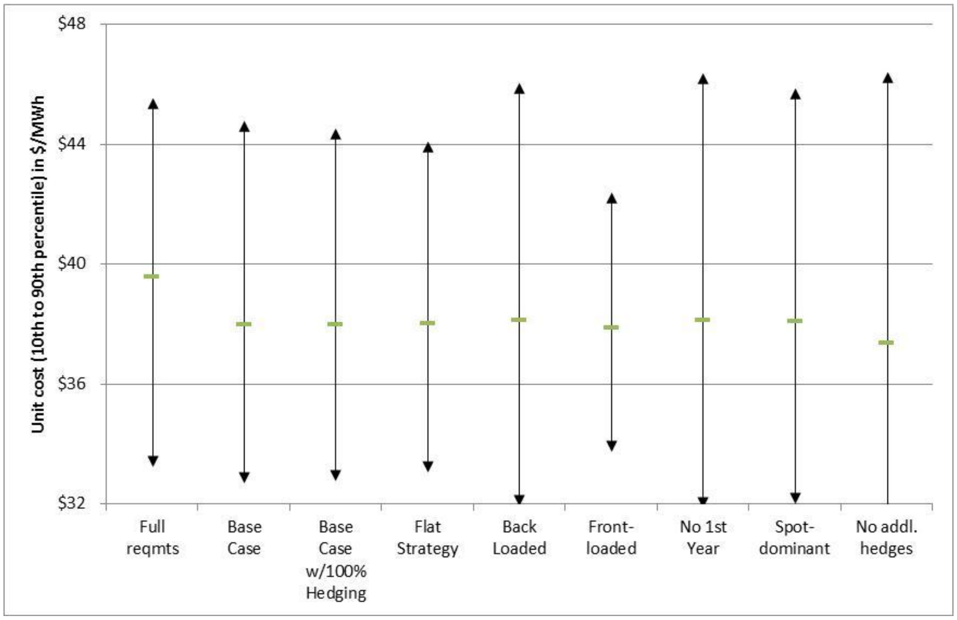
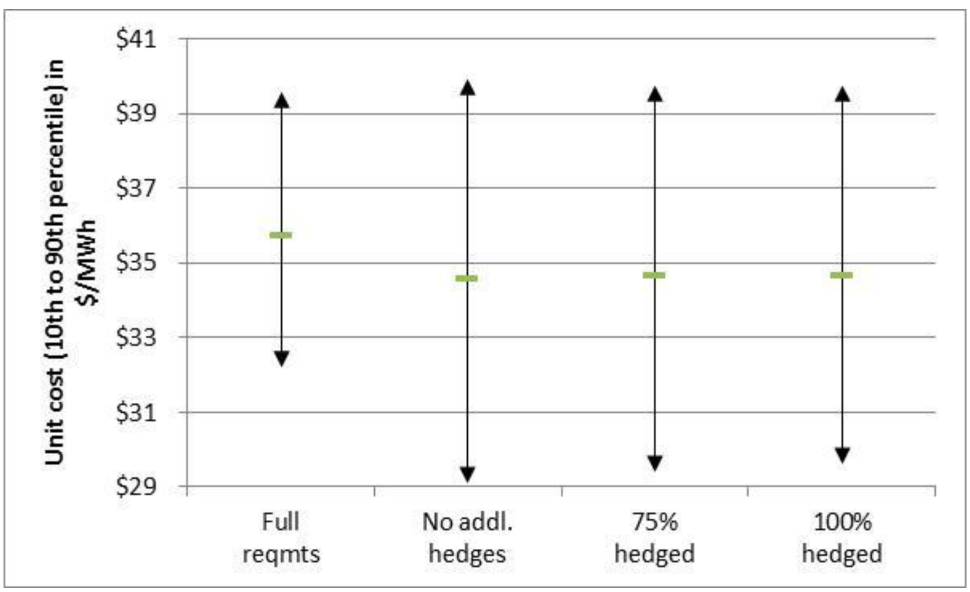


Figure 6-14 Full Requirements Strategy (Including Existing Hedging Gains or Losses) Compared with Conventional Hedging Strategies for 2014-2015, ComEd



The comments above, relating to allocating the impact of the existing hedge portfolio, apply also to ComEd.

6.8 Demand Response as a Risk Management Tool

The discussion above has been focused on traditional energy and capacity supply products. As described more fully in Appendix C – which describes the ComEd load forecast – demand response programs operated by ComEd are not used to offset the incremental demand, over and above the weather-normalized expected case peak load, on days when the weather is hotter than normal. Demand response programs do not affect the weather-normalized load forecast, but they are a supply risk management tool available to help assure that sufficient energy and capacity resources are available under extreme conditions. PJM has a functional capacity market that includes dispatchable demand response as a resource. To the extent that demand response programs receive "capacity credit", PJM pays for this capacity based on the price from the capacity auctions and the proceeds are primarily used to fund payments to the responding customers.

In the case of Ameren MISO provides the ability for demand response measures to contribute to reducing supply risk. Over the past five years MISO has been working with stakeholders through the Demand Response Working Group to incorporate Demand Response Resources into its organized markets.

The IPA added Demand Response Resources to its simulations to estimate their impact on energy costs. The Agency tested the impact of adding 10 MW of demand response to each utility's portfolio; that is almost four times ComEd's annual goal as shown in Appendix C, Table II-8. The impact on energy costs for other customers appears small – two to three cents/MWh (0.002 to 0.003 cents/kWh) if the demand response is called for 50 hours, and four to five cents/MWh (0.004 to 0.005 cents/kWh) if the demand response is called for 100 hours. There appears to be no additional risk reduction benefit (no change to 90th percentile VAR).

Section 7.5 of this plan provides details and additional discussion regarding demand response resources for both ComEd and Ameren.

7 Resource Choices for the 2013 Procurement Plan

This chapter of the 2014 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 market 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

7.1.1 Incremental Energy Efficiency in the 2013 Plan

The IPA's 2013 procurement plan was the first plan to include consideration of incremental energy efficiency programs pursuant to Section 16-111.5B of the Public Utilities Act.[90] That plan included the approval of eight expanded or new programs each for Ameren and ComEd. These programs started implementation on June 1, 2013, and no results or impacts of those programs are yet available.

If Ameren's approved programs from the 2013 plan result in savings in a manner consistent with Ameren's assessment and the Commission's final approval, the Ameren programs are expected to provide incremental net energy savings of 70,834 MWh for the June 2013-May 2014 program year. After considering the impacts of projected customer switching, the anticipated reduction to the energy required for the IPA-procured portfolio is 25,409 MWh for the June 2013-May 2014 delivery year. Ameren further estimated that these programs would reduce demand during peak periods by no more than 4MW. ComEd's Commission-approved programs are estimated to provide an annualized savings goal of 173,753 MWh to the total population of retail customers to which they are being offered. The annual savings estimates for ComEd customers served by the IPA-procured portfolio range from 22,574 MWh for the 2013-14 delivery year to 39,688 MWh for 2014-15. ComEd further estimated that these programs would reduce demand during peak periods by no more than 6MW. It should be noted that each of these savings targets is based on a maximum spending level for the utilities' implementer contracts; the utilities are under no obligation to deliver the exact expected MWh or MW savings.

7.1.2 ICC Workshop

In its approval of the IPA's 2013 procurement plan the ICC ordered workshops to be conducted by ICC Staff to consider the coordination between the incremental energy efficiency programs included in the IPA procurement plan and the programs run under Section 8-103 of the Public Utilities Act, commonly known as the Energy Efficiency Portfolio Standard ("EEPS"). A discussion of those workshops is included below.

In its final order for the 2013 IPA Procurement Plan, the ICC concluded that:

> *It appears to the Commission that no further findings or conclusions regarding energy efficiency programs under Section 16-111.5B of the PUA are required in this proceeding. Because this is the first procurement proceeding to consider the Section 16-111.5B energy efficiency programs, and considering the lack of agreement on other requests, suggestions or recommendations -- for which determinations are not required by statute -- the Commission declines to render a decision or require modifications to the Procurement Plan with respect to these matters. However, in light of the fact that several parties have raised or otherwise addressed additional requests, suggestions, or recommendations regarding the Section 16-111.5B energy efficiency programs that warrant further attention, the Commission directs Staff to work with the IPA to conduct a series of workshops – if the IPA is agreeable to doing so -- to*

[90] Public Acts 97-0616 (creating Section 16-111.5B) and 97-0824 (amending Section 16-111.5B) were first considered for the 2013 Procurement Plan. For a discussion of the statutory requirements of Section 16-111.5B, please see Section 2.7.

> *determine if there are additional changes or refinements to consider with regard to such requests, suggestions, or recommendations in future procurement proceedings.*[91]

ICC Staff held a series of workshops that met multiple times during the spring of 2013. The IPA (and many other stakeholders) actively participated. A Staff Report was issued on August 2, 2013, which provides a high-level view of the topics discussed and ideas shared during the workshops.[92] As noted above, the workshop process, while helpful, did not result in a formal agreement and therefore may not represent the formal opinions of participating parties. Further, the parties sought to, and at times did, reach consensus based on then-current, prevailing information and policy at that time of the discussions. Parties' positions were therefore subject to change based on changes in information and policy. The IPA thus regards the Staff Report as a useful reference point for its discussion, but not a binding document.

The IPA appreciates all of the efforts that ICC Staff and other stakeholders put into these workshops. The topics were extensively discussed and consensus was reached on many items. Although parties generally valued coordination between energy efficiency programs, the "EEPS programs" or "8-103 programs" (i.e. programs authorized by Section 8-103 of the Public Utilities Act, 220 ILCS 5/8-103) have several differences from the Section 16-111.5B energy efficiency programs run through the IPA procurement plan, not the least of which is statutory penalties directed at utilities for failing to reach savings goals for EEPS programs. As a result, many of the discussion items have greater impact on the EEPS programs than on the Section 16-111.5B programs. Other issues, such as verification or "net to gross," certainly play roles in Section 16-111.5B programs, but not necessarily in the front-end approval process to be carried out in this docket. The IPA recognizes that there may be other dockets, especially those to approve Section 8-103 plans, which may be more appropriate venues for the Commission.

To the extent possible it appears that the utilities incorporated consensus of the workshop participants into the development of submittals, and the IPA also has sought to reflect its understanding as the consensus from the workshop in its review of the submittals and the development of this plan. However as discussed below, in some cases the consensus achieved was useful to frame open issues, but the IPA has in its review now identified more detailed issues and related solutions for further consideration among the stakeholders. The IPA explicitly requests that the Commission make determinations on these more detailed issues discussed below.

7.1.3 Additional Policy Considerations

While the workshops addressed many important issues, there are a number of questions that were not fully resolved or discussed completely. However, these questions may directly impact this Procurement Plan and could be addressed in the approval of this Procurement Plan. The IPA requests that the Commission consider these issues and to the extent possible, make determinations that will guide this and future procurement plans.

7.1.3.1 Feedback Mechanisms

The first issue of concern to the IPA is the lack of an adequate feedback loop in the development of programs for consideration for inclusion in the procurement plan to ensure the statutory goal of "fully capturing" the potential for all achievable cost-effective savings, to the extent "practicable."[93] By "feedback loop", the IPA means a process or processes that ensures that energy efficiency opportunities identified in the utility's required potential study that are not met by the third-party RFP process are somehow filled.[94] While several workshop consensus items address what the utilities should include in their submittals to the IPA pursuant to Section 16-111.5B(a)(3), the consensus items may not adequately address this issue. The programmatic planning link between the potential studies and the programs submitted to the IPA is not explicitly spelled

[91] ICC Docket No. 12-0544, Final Order dated December 19, 2012 at 271.
[92] The Staff Report and other documents from the workshops can be found at http://www.icc.illinois.gov/electricity/EnergyEfficiencyWorkshops161115B.aspx.
[93] 220 ILCS 5/16-111.5B(a)(5) (standard for Commission approval of energy efficiency portion of Procurement Plan).
[94] 220 ILCS 5/16-111.5B(a)(3)(A).

out in the statute. The challenge the IPA wishes to address is how to ensure that the statutory goal of "all achievable cost-effective savings" is captured through the process dictated by Section 16-111.5B. The IPA is concerned that the combination of the new programs and expanded utility programs (that each has a TRC of greater than one) may not fully meet the outer boundaries of the potential study in any given year.

The IPA believes that the potential studies could provide a roadmap for what is economically achievable, but if the third-party bids and/or the expansion of existing programs does not fill all the gaps identified in the potential study, there is no mechanism to do further solicitation for programs, or in-house program development. This problem is further exacerbated in years where the EEPS programs are up for review for a new three year cycle and therefore there are not Commission-approved EEPS programs to "expand." In fact, the Procurement Plan this year faces exactly that challenge. With the filing date for approval of the new EEPS programs coming a month prior to the filing date of this Plan (and Commission approval likely after the statutory deadline in the Procurement Plan approval docket), the IPA is unable to determine if there will be approved EEPS programs that meet the opportunities identified in the potential studies that are not otherwise met by the programs submitted to the IPA by the utilities under Section 16-111.5B.

To mitigate this issue, the IPA suggested that in the consideration of this year's draft Plan for comments, the stakeholders recommend changes to the third-party bidding process to allow for more flexibility in the bidding procedure to help identify more programs that are technically and economically "feasible," "cost effective," and "practicable" as required by statute. In the comments received on the draft plan, several parties pointed out that the additional feedback mechanisms may just lengthen an already very long process between RFP responses and program implementation. The IPA does not recommend supplemental RFPs to be held to "fill in" categories of the potential study that are not filled by third party bidders. There were also suggestions on how to clarify the third-party bid RFPs (discussed further in Section 7.1.3.4) and to give vendors opportunities to adjust their proposals.

NRDC raised an interesting point that the third party bids tended to be focused on retrofit programs rather than programs that would influence the purchase of efficient products. The IPA does not have a position at this time as to whether this trend overall is good or bad, but this issue may be worthy of future examination, including the impact on reaching the limits of the potential study for purchase of efficient products. If the Commission (or the IPA at a future date) believes this is problematic, the IPA believes two questions are important to answer: First, are there structural limitations to the Section 16-111.5B process that lead to this outcome? Second, if there are structural limitations, is this inherently a problem or do the opportunities created by Section 8-103 or utility-run programs adequately address them?

The IPA recommends that the Commission consider stakeholder input on this issue and provide clarity to the utilities for next year's RFPs, if possible. This issue may not be possible to properly resolve absent legislative changes to Section 16-111.5B. In the interim, the IPA believes that any direction the Commission can provide on this issue will aid bidders and the utilities to provide a set of achievable cost effective energy efficiency programs to the Commission which will allow the Commission to make the necessary statutory findings pursuant to Section 16-111.5B(a)(5) of the Public Utilities Act.

7.1.3.2 Transition Year Program Expansion

A second issue of concern is the uncertainty described above regarding this transition year where the EEPS programs for next year are not yet approved. In years where EEPS programs are already approved, the consideration of expansion of those programs can follow a logical path, but that path is not available this year. A consensus item from the workshops was that Section 8-103 and Section 16-111.5B filings could have their timelines aligned. While this would be helpful on some level because the stakeholders in the IPA plan approval process would know what programs are under consideration in the Section 8-103 proceeding, it will not fully address the issue that those programs are not actually approved by the time the Commission must approve the IPA's procurement plan. In their submissions to the IPA for this procurement plan, the utilities have addressed the expansion issue by seeking approval for some programs through Section 16-111.5B and others pursuant to Section 8-103 (rather than expanding existing programs previously approved pursuant to Section 8-103). In 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.

7.1.3.3 DCEO Participation

The third issue of concern is how the Department of Commerce and Economic Opportunity ("DCEO") can participate in the Section 16-111.5B process. There was consensus in the workshops that DCEO *should* participate in the Section 16-111.5B process, and DCEO programs that have a TRC exceeding one should have a mechanism for inclusion in the Section 16-111.5B procurement (perhaps via the RFP process, although the exact procedure was not fully discussed). The workshop did not fully resolve significant details, such as how DCEO should (or may) participate. However, because the utility energy efficiency RFP process for this procurement planning cycle has already passed, to the extent DCEO participation in the utilities' RFP process is feasible, it is not available for this Procurement Plan. The IPA also understands that DCEO may have some administrative limitations regarding contracting that could preclude that option in future years; the IPA hopes that DCEO will provide additional details on this matter in objections.

DCEO provided to the IPA on July 15, 2013 a proposed filing under Section 16-111.5B that included incremental energy efficiency programs that DCEO stated pass the Total Resource Cost Test ("TRC"). The IPA determined that it could not include the programs proposed by DCEO pursuant to Section 16-111.5B at this time because DCEO is not a utility as the term is used in Sections 16-111.5 and 16-111.5B.[95]

The IPA recognizes that the programs proposed by DCEO have great potential value (the TRCs of both programs easily exceeded one), especially to low income customers, but the IPA is restricted to the parameters of statutory and ICC authorization in its ability to include the DCEO filing in its submittal of the procurement plan to the ICC. In light of the limitations of Section 16-111.5B, the IPA requested additional proposals for creating a mechanism for their inclusion in this plan.[96]. To facilitate concrete discussion (and perhaps Commission approval) the IPA is placing DCEO's submission in this docket's record, the DCEO submittal is attached as Appendix H. It appears that of the two programs included in the proposal, one (street lighting enhancement) would be a new program, while the other (Energy Savers) is an expansion of a program that DCEO has now included in their August 30, 2013 Section 8-103 filing before ICC.[97]

The IPA hopes that the discussion of this issue will help provide a template for a process for use in future years that could result in upfront coordination between DCEO and the utilities that would allow for DCEO programs to be included. The IPA further notes that it will follow any Commission Order interpreting Section 16-111.5B to require inclusion of DCEO programs in this year and prospectively in future years.

7.1.3.4 Consideration of All Third-Party Bids

The final issue is competition between incumbent utility programs and third party RFP programs. Specific instances are discussed below, but at a high level there are two issues.[98] The first issue is what it means for a third-party bidder's proposed program to be "competing" with or be "duplicative" of a utility program. Although it may be obvious in some cases (such as with Ameren's SAIC Small Business Direct Install program, discussed further below) where a third-party bidder is seeking to serve the exact same market with similar or the same energy efficiency solution, the IPA is not aware of a Commission-approved standard for these terms in the context of Section 16-111.5B. Based on the comments received on the draft plan, the IPA proposes to use 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. The nature of the energy efficiency market is that in many cases efficiency is derived from single distribution channels. In the

[95] In 2012 DCEO also provided a similar filing. The IPA did not include DCEO's proposed programs for the same reasons, and additionally because the filing was made after the July 15, 2012 filing deadline that applies to utilities.
[96] Such proposals would at minimum need to address statutory and regulatory authority to include the programs as well as to define the cost recovery mechanism for the programs.
[97] See ICC Docket No. 13-0499.
[98] In the IPA's review of the Commission's Order approving the 2013 Procurement Plan, the IPA did not see that these items were directly addressed, although parties may have raised similar issues.

same way that having many supplier options (from bundled rate to residential real-time pricing to retail service) benefits consumers by offering a variety of energy services, there could be energy efficiency offerings that would benefit from multiple channels. While there do not appear to be such programs in this year's submittals, the IPA suggests using the term "competing" for such programs if they are proposed in future years. The general goal would be that duplicative programs are to be avoided, but that competing programs would be acceptable to the extent that the competition does not render one or both non-cost effective.

The second issue is the authority of the Commission to reject a third-party bidder's program that is "competing" with or "duplicative" of a utility's program but which otherwise passes the standard for cost-effectiveness. Section 16-111.5B does not directly address this matter, although it is possible to read the statutory terms "new," "expanded," and "incremental" as requiring new programs that are additive (*i.e.* non-competitive and non-duplicative) to utility programs. The Commission may wish to clarify if the utilities may screen out those programs pursuant to Section 16-111.5B(a)(3) or whether the IPA must include all "competing" or "duplicative" programs and then request that the Commission remove those programs pursuant to Section 16-111.5B(a)(5).

The IPA sought comments on these issues and after reviewing those comments, the IPA recommends continuing the process followed this year that does not set a specific standard. In this process each utility would continue to provide to the IPA all third-party bids received, and further the utility would provide an initial recommendation regarding any screening out of programs that the utility deems to be duplicative. The IPA would then include in its filing to the Commission its assessment of all bids received and its assessment of the screening (if any) done by the utility. The Commission would then provide the final determination as to which programs are included based on any objections received that would change the Commission's understanding of if the program in question is or is not duplicative or competing.

In general stakeholders felt that it was important for the Commission to have the opportunity to review information regarding all bids, and also that the utilities be given some level of discretion (although stakeholders did not agree on just how much) in judging which programs to include and which ones were duplicative and did not add value. The IPA recognizes that the marketplace for energy efficiency is dynamic and that TRC calculations are generally done in isolation (*i.e.* imagining that each program is not competing with the same or similar programs for market share). Including duplicative or competing programs could impact the accuracy of the TRC test.

If the Commission chooses to adopt a standard for duplicative or competing programs, the IPA suggests that the standard be a multi-factor inquiry rather than a "bright line" test. Factors that the IPA suggests that the Commission consider to be part of the standard include (but are not limited to): (1) similarity in product/service offered; (2) market segment targeted, including geographic, economic, and customer classes targeted; (3) program delivery approach; (4) compatibility with other programs (for instance, a program that created an incentive to accelerate the retirement of older inefficient appliances could clash with a different program that tunes-up older appliances); and (5) likelihood of program success (a proven provider versus an undercapitalized or understaffed provider, if such evidence is placed in the record). The IPA invites parties in objections to recommend additional criteria or modify the criteria suggested above.

The IPA notes that in reviewing the RFPs issued by the utilities they do contain guidance to potential bidders regarding not proposing duplicative programs. Some stakeholders believe that this language may have been unclear or confusing. The IPA suggests that for future RFPs the utilities work with stakeholders to refine that language to make it clearer to potential bidders.

7.1.4 Ameren

Ameren's submission 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 submission including its own seven appendices may be found on the

IPA website posting of the 2014 Procurement Plan at www.illinois.gov/ipa. Two of the Appendices (6 and 7) in Ameren's submittal contain confidential data, and are redacted.

Ameren's proposal contains programs and measures that were "expanded" from the Section 8-103 by virtue of being removed from Ameren's Section 8-103 three year plan filing[99] and moved to and expanded in its IPA submission. Examples include moving specialty lighting, electric home improvements, small business incentives and multifamily common area measures out of their Section 8-103 portfolio and into the IPA submission at higher than previous levels.

In its submittal, Ameren also stated that, "[T]his submission represents one year of savings and costs. However, AIC reserves the right to submit multiple years of programs and related savings in future submissions."[100] One impact of this approach is that the MWh goal of the submittal is smaller than that of the previous year, in part for the simple reason that it includes only stand alone programs rather than last year's the expansion of programs authorized pursuant to Section 8-103. The lack of Section 8-103 programs to expand illustrates the open issue raised above about years in which a three-year energy efficiency plan is under consideration.

Ameren's assessment includes five energy efficiency offerings in this Procurement Plan. All of these programs passed the TRC test at the time of assessment.[101] These programs are exhibited in Table 7-1,

Table 7-1 Ameren Energy Efficiency Offerings

Program	Net Savings (MWh)	Total Utility Cost	TRC
Multifamily	14,247	$4,292,956	2.95
Specialty Lighting	5,970	$2,794,093	1.12
Rural Efficiency Kits	3,555	$377,365	3.28
All-Electric Homes	11,189	$7,039,702	1.49
Small Business Direct Install	30,719	$8,715,840	1.14

The total net savings for these programs is estimated as 65,680 MWh at the busbar.[102] The programs also contribute to a peak reduction of approximately 2 MW. The estimated savings attributable to eligible retail customers is 17,950 MWh. The IPA believes that subject to the modifications and open issues discussed below, Ameren's submission meets the requirements of Section 16-111.5B(a)(1)-(3) and the programs listed in Appendix B should be approved pursuant to Section 16-111.5B(a)(5).

In addition to its own programs ("Ameren programs") Ameren assessed six additional programs from third party vendors ("Bidder programs"). Three Bidder programs did not pass the TRC; one program was determined by Ameren to be duplicative of the existing SAIC Small Business Direct Install program, one program was excluded because it was designed as a gas and electric savings program that assumed participation by a separate gas utility that could not be assumed, and another program was the expansion of the SAIC Small Business Direct Install program.

7.1.4.1 Ameren Duplicative Program

The IPA has reviewed the Bidder program that Ameren considered duplicative of SAIC Small Business Direct Install program and it illustrates the challenges of the "competing" and "duplicative" issue highlighted in Section 7.1.3.4. The Bidder program would specifically target class B and C commercial office spaces, which is a smaller market subset of the SAIC Small Business Direct Install program. Class B and C office spaces are

[99] See ICC Docket No. 13-0498.
[100] Appendix B, Energy Efficiency Submittal at 4.
[101] Ameren also provided the results of the UCT test and one program did not pass 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.
[102] Note that in Ameren's submittal document net savings are primarily listed as at the meter. For consistency net savings in this plan are listed at the busbar.

already served by Ameren's program (but not specifically targeted), so failure to include the Bidder program would not hinder the statutory mandate to expand cost effective energy efficiency programs. On the other hand, there could be value in testing alternative delivery mechanisms for this specific sector if, in fact, the Bidder program is superior (although there is not sufficient information in the submittal to determine that). Absent any determination that this program in fact is not duplicative (albeit more targeted) of what Ameren will already offer in the SAIC Small Business Direct Install program, the IPA recommends that the Commission not approve the inclusion of this program as its inclusion may not be "practicable."

7.1.4.2 Ameren Student Energy Kits

Ameren also proposed excluding a Bidder program that would deliver education kits to students via the classroom. Ameren stated that it did not include the program because it is a gas and electric savings program and Section 16-111.5B specifies that the IPA energy efficiency programs be provided and coordinated by the electric utilities for the purposes of electric savings. Ameren further noted that the program targeted an area where Ameren was not the gas utility, that the gas utility in question (Nicor Gas) is not a participant in this procurement process and that their participation cannot be ensured or required. In comments Ameren further stated that they did not evaluate or validate this vendor in terms of its ability to actually deliver the program, its reputation, credit worthiness or references once it was determined that the program was not applicable to this procurement process. Therefore, in the event the program is conditionally approved, the program's inclusion should also be subject to Ameren's evaluation and validation of the vendor.

Ameren's August 31, 2013 Section 8-103 filing (which, unlike Section 16-111.5B, addresses both gas and electric energy efficiency because Ameren is a combination utility) included a proposed student energy kit program by a different vendor and at a substantially larger scale. While the IPA has not conducted a thorough comparison of the details of the two programs, the presence of that proposed program suggests that this market sector may be well served. Notwithstanding the contractual issues identified, assuming that the Section 8-103 program is approved by the Commission, the IPA does not recommend the inclusion of the student energy kit program under Section 16-111.5B.

7.1.4.3 Ameren's Expansion of Small Business Direct Install Program

Ameren included in their submission a base program for small business direct install. They also included in their assessment the bid for an expanded version of the program (73,435 MWh versus 30,719 MWh) but recommended the base level – a continuation of the same size of program from the previous year (which began implementation in June, 2013) – because in Ameren's view it is, "prudent and responsible to first assess and evaluate the performance of this program prior implementing it again on a larger scale."[103] The IPA appreciates the program management and evaluation issue that Ameren raises, but notes that programs implemented under Section 16-111.5B do not have penalties for non-performance. In comments, Ameren also raised the issue of risks associated with the ICC reconciliation review, which examines Ameren's management of the program. The IPA understands and appreciates that utilities are always subject to the review of certain management and performance standards by the ICC, and that placing unrealistic expectations on any utility program could theoretically force imprudent steps that could jeopardize cost recovery. However, the IPA would like to see more discussion from Ameren as to why an expansion of the program to a level first raised by Ameren, or its vendor, would lead to that result.

7.1.4.4 Ameren Requested Determinations

Ameren also requested in their filing that the ICC make several determinations:

- "[I]t is realistic to assume that actual market results will differ from anticipated results. Therefore AIC formally requests approval for an indeterminate fluctuation in savings that may occur by program year end."[104]

[103] Appendix B, Energy Efficiency Submittal at 12.
[104] I*d.* at 8.

- Ameren, "seeks confirmation that AIC is permitted to recover costs that incidentally (3 - 5%) exceed the estimated program costs as consistent with the Commission finding in the ComEd energy efficiency 'Plan 2' plan docket #10-0570."[105]. This was a consensus item from the workshop. Ameren further notes that, "In lieu of this express approval AIC will be forced to prematurely discontinue approved programs prior to the budget cap being expended."

- "AIC notes that the savings estimates were determined using the current Illinois TRM and NTG values and unless these values are fixed, they are subject to change. With this submission, AIC is formally requesting that these values are fixed for implementation and evaluation for the determination of achieved savings."[106]

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

Besides these determinations, the IPA requests that the ICC at minimum approve the incremental energy efficiency programs proposed by Ameren and that the ICC further consider the additional recommendations of the IPA as set forth herein.

7.1.5 ComEd

ComEd's submission 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 2014 Procurement Plan at www.illinois.gov/ipa. Note that the document entitled "ComEd 2013 Third Party Efficiency Program Summary of Vendor Scoring Process, July 5, 2013" contains confidential data and is redacted from this Plan.

ComEd's assessment includes eight energy efficiency offerings in this Procurement Plan. All of these programs passed the TRC test at the time of assessment.[107] These programs are exhibited in Table 7-2.

Table 7-2 ComEd Energy Efficiency Offerings

Program	Net Savings (MWh)			Three Year Program Cost	TRC
	Program Year 1	Program Year 2	Program Year 3		
Home Energy Reports	301,780	374,971	390,233	$41,552,668	1.90
Small Business Energy Services	111,020	147,657	185,403	$110,013,985	2.32
CUB Energy Saver	6,628	13,256	19,884	$1,775,000	1.72
Home Energy Services	2,239	2,239	2,239	$4,701,285	1.23
Small Commercial Power Strip	4,840	-	-	$1,267,000	1.05
Energy Stewards	1,366	-	-	$200,000	1.97
Small Commercial HVAC Tune-up	3,690	10,335	12,170	$6,841,506	1.78
Retrofit Chicago Residential	1,285	1,685	2,029	$1,667,667	1.18

ComEd proposed both multi-year and single-year programs. The net savings at the busbar are 432,848 MWh for the first program year, 550,143 MWh in the second program year and 611,958 MWh in the third program

[105] *Id.* at 8.
[106] *Id* at 11; *see also id.* at 14 (similar language).
[107] ComEd also provided the results of the UCT test and one program did not pass 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.

year. These programs will deliver 16 MW of reduction in peak procurement for the 2014-2015 program year. The savings attributable to eligible retail customers is 88,839 MWh in the first program year, 137,288 MWh in second program year, and 184,078 MWh in the third program year. The IPA believes that subject to the proposed modifications and resolution of the open issues discussed below ComEd's filing meets the requirements of Section 16-111.5B(a)(1)-(3) and the programs listed in Appendix C should be approved pursuant to Section 16-111.5B(a)(5).

As with Ameren, ComEd's proposal contains programs that it determined fit best in the Section 16-111.5B model but which had previously been part of EEPS. For ComEd these programs are the Home Energy Report and the Small Business Energy Services. And as with Ameren, these programs are included at scales larger than had been implemented under EEPS and are therefore considered program expansions.

ComEd evaluated 17 third party bids. A summary of the bids is included in Appendix C-4. ComEd included six of them (Bid numbers R1, R2, R4, M1, B1, and B3) in its submission to the IPA.[108] Of the eleven Bidder programs that were not included, one program was withdrawn by the bidder (B2), three programs were determined to be incomplete or unresponsive (M3, B4, and B8), one did not pass the TRC (R3), and six were deemed by ComEd to be duplicative of other proposals that ComEd considered. Of the six Bidder programs that ComEd considered duplicative, one was duplicative of ComEd's current multifamily program, two were duplicative of other current ComEd energy efficiency programs, and three were duplicative of the Small Business Energy Services that ComEd is including in its Section 16-111.5B proposal. The duplicative multifamily program (M2) also failed the TRC test.

As noted above, the Commission has not provided a standard pursuant to Section 16-111.5B for evaluating "competing" or "duplicative," and has not provided direction about how to deal with "competing" or "duplicative" programs. The IPA therefore provides the following discussion and recommendations on how to address each specific program.

7.1.5.1 ComEd Duplicative Programs (Current Portfolio)

For the two Bidder programs (B9 and B10) that compete with existing ComEd Section 8-103 programs the IPA notes that ComEd describes them as "substantially identical" to the existing programs. However, the ComEd Commission-approved programs are part of the Section 8-103 3-year plan portfolio that is ending this year and will be up for renewal concurrently with the Procurement Plan approval docket. ComEd has subsequently proposed programs in its August 31, 2013 Section 8-103 filing[109] which in substance appear to continue those existing programs. . The IPA recognizes that there is a risk of the programs not being approved in the Section 8-103 proceeding, and also that Section 8-103 programs are subject to savings goals that lead to penalties if not met. As a compromise approach the IPA recommends that the Commission consider conditional approval of the two programs. If the Commission subsequently does not approve the competing programs in its Section 8-103 plan then these programs (B9 and/or B10) should proceed. On the other hand if the Section 8-103 programs are approved by the Commission then this conditional approval should be rescinded. Because it appears that these programs have been put forward for approval in ComEd's Section 8-103 proceeding, the IPA recommends that this conditional approval should not be reflected in the load forecast included in this Plan. By the time of the proposed March load forecast update, this issue should be resolved and the load forecasts could be updated as needed.

7.1.5.2 ComEd Duplicative Programs (Small Business Energy Services)

A different issue arises for the three Bidder programs that ComEd excluded that are duplicative of the Small Business Energy Services program that ComEd included in its Section 16-111.5B filing. One of the Bidder programs (B7) appears to have a scope as wide as the Small Business Energy Services Program in terms of customers, but has a significant geographical limitation. The IPA does not see a compelling reason to include this program and defers to ComEd's determination to include its core Small Business Energy Services program to serve that sector. The other two programs appear to target specific business sectors and as

[108] For more information on the included bids, see Appendices C-3 and C-4.
[109] See ICC Docket No. 13-0495.

suggested with the similar Ameren submittal, the Commission may only want to consider including them if it is determined that they are not truly duplicative.

7.1.5.3 ComEd Requested Determination

ComEd has requested that, "[t]o the extent that the IPA and the ICC approve procurement of the programs ComEd requests that the approval be for all three years."[110] In light of the consensus item that multi-year programs should be approved through the Section 16-111.5B process and because the programs' TRC calculations are greater than one for a multi-year timeframe, The IPA agrees with that request.

Besides this determination, the IPA requests that the ICC at minimum approve the incremental energy efficiency programs proposed by ComEd and that the ICC further considers the additional recommendations of the IPA.

7.1.6 Energy Efficiency as Supply Resource

The IPA requested feedback from stakeholders on the concept of using energy efficiency as a supply resource that could reduce the need for procurement. The most detailed feedback received was that submitted by CUB. CUB proposed several possible program structures including ones to address high load hours, high price hours and peak hours. The IPA appreciates these suggestions and is most intrigued by the high load model. While the other two may have significant potential value to consumers, the high load model would appear to be the model that would most likely fit into the procurement processes that the IPA can, and does, conduct. The model also appears to be similar to an existing program in ISO New England that could provide a starting point for consideration.

ComEd and Ameren recommended removal of this section from the plan because it did not propose a specific procurement for 2014. The IPA agrees that because it is not proposing such a procurement in the 2014 Procurement Plan, the IPA will not add additional specifics at this time. Instead, the IPA proposes to conduct workshops and receive stakeholder input in early 2014 to further explore this model for the possible inclusion of a more specific proposal in future procurement plans.

The AG, NRDC, and the Sierra Club all commented on the underlying discussion, including the contention that the current Section 16-111.5B process does not sufficiently incentivize peak load reduction. The IPA appreciates these comments, and will take these comments into account in developing a proposal for the workshop process.

7.2 Procurement Strategy

The selection of the Agency's procurement strategy is driven by the following challenges:

- Price hedging: the Agency ought to find the best compromise between hedging against adverse price movements and retaining the flexibility to respond to rapidly changing market conditions
- Load hedging: the accuracy of load forecasts increases as time to delivery decreases particularly with regard to switching risk. For instance, load forecasts for the delivery year 2014-2015 that the utilities will submit in March 2014 should be more accurate than the forecasts for that year submitted in July 2013. Therefore, the Agency ought to ensure it has the opportunity to adjust its supply strategy to account for changes in load forecasts
- Control of overhead cost: RFPs for energy contracts are costly and the Agency ought to take this into account in its procurement strategy.

In order to address these challenges, the Agency's procurement strategy has historically been designed in a "laddered" fashion: a large fraction of the load would be purchased for the prompt (upcoming) delivery year

[110] Appendix C at 26.

while smaller fractions of the load would be purchased for the subsequent two years. Prior to the 2013 Procurement Plan, the IPA procurement strategy for energy products was designed to result in a ladder of products predicated on being 100% hedged for the prompt year, 70% hedged for the second year, and 35% hedged for the third year.

The laddered strategy is used to mitigate price risk, smooth out price spikes, and minimize exposure to any single set of forward prices. Due to accelerated customer switching, and, to a lesser extent, to declining market prices, the IPA considered a revised strategy in the 2013 Procurement Plan in that 75% of the load would be hedged for the prompt year, 50% for the second year and 25% for the third year. By reducing the total hedge, the utilities partly reduced their exposure to load loss, while the generally stable or declining market price environment reduced the penalty for underhedging. Ultimately the IPA recommended this revised strategy be deferred until future Plans and the ICC agreed.

The analyses in Chapter 6 indicated that, under the assumptions of that chapter, while hedging could reduce the impact of forward price uncertainty it could not counter the effect of load uncertainty, a somewhat more significant impact (Section 6.5.2). The following are conclusions relevant to procurement strategy that may be drawn:

- Load reduction is a particularly significant risk because losses associated with currently out-of-market hedges will have to be spread over a smaller pool of kWh. The utilities' load forecasts, summarized in Sections 3.2 and 3.3, did not assess the probabilities of their high and low load scenarios. Ameren's high and low scenarios each had the same weight in the Monte Carlo model used for Chapter 6, and ComEd's high and low scenarios each had the same weight (although it was different from the weight on each of the Ameren high and low scenarios). Given the high current levels of municipal aggregation, it seems more likely that there will be a "rebound" effect reversing switching in the coming years. This effect was observed in Ohio, followed by a re-reversal (Figure 6-10).
- Switching decisions, especially having to do with municipal aggregation, have effects lasting two to three years. This distinguishes switching-related load variation from price variations, which decay much more quickly. It makes sense to delay forward purchases to the extent that they create load risk. The uncertainty in load forecasts should be reassessed each year. For example, in previous years a 100%/70%/35% procurement strategy seemed reasonable. In 2013 it was considered that the potential for load reduction made that strategy too risky and that forward purchases should be delayed with a 75%/50%/25% strategy. However, no formal request was made of the ICC in this regard given that no procurements were required in that plan.
- On the other hand, if the volume of load that could return to utility service is now greater than the risk of additional switching away, and if upside price risk is greater than downside risk, then the situation of the last couple of years could reverse and it would make more sense to be fully hedged close to the delivery month. In fact, the impact of shaping, as noted in Chapter 6, can be mitigated by hedging at about 106% of average load June through October and 100% of average load November through May, so that "fully hedged" should be interpreted as 106% of average load June through October and 100% of average load November through May. Being fully hedged close to the delivery month will also help to reduce the volatility of PEA.
- Forward contracts do not necessarily provide perfect hedges against load uncertainty; however, other products, such as full requirements hedges, are available in the market at premium prices.

7.2.1 Standard Market Products

The IPA recommends that the basic strategy discussed in the 2013 Procurement Plan be slightly modified. The procurement goal for a mid-April 2014 procurement event is to hedge 106% of the expected load forecast for June-October 2014 and 75% for November 2014 – May 2015. The Agency recommends that the utilities update their load forecasts in March 2014 subject to the consensus of the utilities, IPA, ICC Staff, Procurement Administrator(s) and Procurement Monitor, the recommendations in Table 7-4 through Table 7-11 be recomputed and further include and any Commission-approved energy efficiency programs and the impact of any partial curtailment of long term renewable contracts.

The March 2014 forecasts should include the effect of approved energy efficiency programs and provide the expected case as well as the high and low scenarios. Absent any large reduction in the Required Purchase Amounts, a procurement event should be held in April, 2014 for each utility to acquire contracts: for Ameren in the Required Purchase Amounts of Table 7-4, Table 7-6, and Table 7-7 and for ComEd in the Required Purchase Amounts of Table 7-8, Table 7-10, and Table 7-11.

The Agency also seeks approval for conducting a procurement event in September 2014 to bring the hedge levels to 100% for the period November 2014 to May 2015. However, the Agency further recommends that, after taking into account the utilities' July 2014 forecasts, which the Agency recommends be expanded to include the November 2014 to May 2015 period, it be given the authority, in consultation with ICC Staff, ComEd, the procurement administrator, and the procurement monitor, to forego the September procurement if consensus is reached that the procurement would not be cost effective. Factors that the IPA proposes to consider in making such a determination would include if the utilities' forecasted loads drop significantly, the risk associated with keeping the open position compared to the cost of running the auction, and the scale of the supplier fees required to recover the cost of the procurement. (This forecast for the November 2014 to May 2015 produced by the utilities in July 2014 will have no impact on the partial curtailment of long term renewable contracts which would have occurred prior to the 2014-2015 plan year and will be based on March 2014 forecast). The second procurement should be scheduled such that the ICC has time to approve any new procurement no later than September 22, 2014 in order to allow for prices for the non-summer period to be reset before the period begins.

Table 7-3 Summary of Hedging Strategy

Mid-April 2014 Procurement			Mid-Sept. 2014 Procurement
June 2014-May 2015 (Upcoming Delivery Year)	Upcoming Delivery Year+1	Upcoming Delivery Year+2	November 2014-May 2015
106% (June-Oct.) 75% (Nov.-May)	50%	25%	100%

If there is a rebound effect from municipal aggregation, the utilities may actually experience a switch of the load back to them in the near future upon contract expiration, (the schedule of expirations is shown in Figure 3-20). Because of this uncertainty, a bifurcated (April/September), fully hedged strategy in the 2014-2015 delivery year is a prudent option.

For the 2014 Procurement Plan, the Agency recommends purchases of standard forward block hedges in multiples of 25MW, as opposed to 50MW as in the previous plan, for the following reasons:

- The smaller individual increment provides a greater ability to accurately match load (25MW increments vs. 50MW increments), and therefore limits reliance on the spot market as a balancing mechanisms during hours of imbalanced supply.
- Liquidity appears adequate, given that index publishers such as Platt's survey transactions down to 25 MW.[111]
- They are standardized products with published definitions.
- Suppliers can hedge their own exposure in futures and/or forward markets.

[111] "Standard-size packages are multiples of 25 MW": Platts, *Methodology and Specifications Guide: North American Energy,* at http://www.platts.com/IM.Platts.Content/MethodologyReferences/MethodologySpecs/na_power_method.pdf, p. 4.

7.2.2 Other Products

The IPA considered other products that provide hedges against load uncertainty, namely full requirements products and options.

The analysis in Chapter 6 indicates that full requirements products do not have a great cost or risk advantage over a block-based strategy. The analysis in Section 6.7 depends on a theoretical or conceptual model of how suppliers would price full requirements products. Prices may be less than the model implies, but on the other hand they may be much greater given the current load uncertainty discussed above.

The IPA is not prepared to recommend the use of full requirements products. The IPA is not aware of any recent assessments of the risk tolerance of retail customers; that is, their willingness to pay the utility for price insurance. Customers can easily switch to a competitive supplier and take fixed price service if they perceive value of mitigating price risk.

The IPA, in the preparation of this Procurement Plan, also considered a pilot program, involving only a fraction of the utilities' load, but decided that the overhead cost of designing a price benchmark and a procurement mechanism for such a different product is not justified given that hedging using standard block products represent a less expensive alternative. A successful pilot program must also provide meaningful results that can be assessed and provide input into future decisions. It was not clear to the IPA how such a pilot program in this Plan could provide those types of results in time for meaningful decisions that could inform future procurement plans.

Chapter 6 included a description of option products (Section 6.2.1). A call option could be used to hedge against future energy price increases if more load switches back to the utilities than forecasted. A put option could be used to hedge against energy price decreases if additional load switches from the utility; load loss due to additional switching compounds the financial risk of out-or-market hedges. The Agency did not conduct a full analysis of the economic and regulatory implications of including options in the 2014 Procurement Plan; however, the IPA plans to investigate those implications in developing its 2015 Procurement Plan.

7.2.3 Portfolio Rebalancing

Section 16-111.5(b)(4)(ii) requires that a procurement plan include "the criteria for portfolio re-balancing in the event of significant shifts in load." Historically, the IPA has used the utilities' updated March forecasts as the criteria for determining whether to re-balance a utility's portfolio. In particular, in last year's plan, the IPA focused specifically on the impacts to the forecast resulting from municipal aggregation in determining the need for re-balancing the portfolio.[112] Once again, the IPA proposes to use the utilities' updated March 2014 forecasts for the purposes of determining whether to re-balance the portfolio. Also, once again, municipal aggregation will be the primary criteria for making that determination. As discussed in Section 3.3.3 above, numerous supply contracts for municipal aggregation will be expiring in the 2014 Planning Year. The utilities should survey all such municipalities and on the basis of those surveys update their March 2014 forecasts accordingly.

In the 2013 Plan, the IPA noted that Ameren was substantially over-hedged and considered the benefits and drawbacks of holding the long position and allowing the hedges to settle in the MISO day-ahead market (as opposed to organizing a reverse RFP). The IPA believes that the risk of holding a long position could be mitigated by selling excess supply in the forward market in mid-September 2014. This belief is supported by the quantitative analysis in Section 6.6.2. However, in practice, the expected cost of holding the reverse RFP and the expectation that bidders would bid to buy the excess supply at or below the bid mark, could reduce the estimated benefit and produce a real financial loss that is perhaps equal or greater than the estimated avoided risk of holding the long position (about $0.30/MWh, plus $0.06/MWh in avoided expected cost). Additionally, the IPA notes that the excess supply in the Ameren portfolio is comprised of supply acquired as

[112] ICC Docket No. 12-0544, Final Order dated December 19, 2012 at 67-69, 109-10.

the result of mandated rate stability procurement; it is unclear whether selling such supply back to the market is permissible or prudent. The IPA, for these reasons, and for this Plan, does not recommend that Ameren rebalance its portfolio in an organized reverse auction and therefore recommends the position settle within MISO at the prevailing LMP

7.3 Quantities and Types of Products to be Purchased

7.3.1 Ameren

7.3.1.1 Ameren Procurement Delivery Years 2014 - 2017

Table 7-4 Ameren Procurement, Delivery Year 2014-2015, (To Be Conducted Mid-April 2014 Based on the March 2014 Expected Load Forecast, Including Approved Energy Efficiency Programs)

	Expected Load (MW)		106% (June-Oc.) or 75% (Nov-May) of Expected Load MW		Current Contracted Supply (MW)		Required Purchases (MW)	
	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak
June-14	734	551	778	584	692	696	75	0
July-14	802	696	850	738	676	687	175	50
August-14	777	660	823	700	680	694	150	0
September-14	567	504	601	535	689	696	0	0
October-14	488	409	517	434	716	729	0	0
November-14	541	490	406	367	736	732	0	0
December-14	632	589	474	442	715	717	0	0
January-15	662	632	496	474	726	726	0	0
February-15	624	609	468	457	717	723	0	0
March-15	508	472	381	354	723	739	0	0
April-15	444	408	333	306	733	741	0	0
May-15	449	412	337	309	717	718	0	0

Table 7-5 Ameren Procurement, Nov.-May of Delivery Year 2014-2015, (To Be Conducted Mid-Sept. 2014 Based on the July 2014 Expected Load Forecast, Including Approved Energy Efficiency Programs)

	Expected Load (MW)		100% of Expected Load (MW)		Anticipated Contracted Supply (MW)*		Required Mid-Sept. 2014 Purchases (MW)	
	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak
November-14	541	490	541	490	736	732	0	0
December-14	632	589	632	589	715	717	0	0
January-15	662	632	662	632	726	726	0	0
February-15	624	609	624	609	717	723	0	0
March-15	508	472	508	472	723	739	0	0
April-15	444	408	444	408	733	741	0	0
May-15	449	412	449	412	717	718	0	0

*Including any purchases made in mid-April

Table 7-6 Ameren Procurement, Delivery Year +1 (2015-2016), (To Be Conducted Mid-April 2014 Based on the March 2014 Expected Load Forecast, Including Approved Energy Efficiency Programs)

	Expected Load (MW)		50% of Expected Load (MW)		Current Contracted Supply (MW)		Required Mid-April 2014 Purchases (MW)	
	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak
June-15	633	517	317	258	236	245	75	25
July-15	744	612	372	306	223	235	150	75
August-15	712	600	356	300	227	240	125	50
September-15	509	470	254	235	235	242	25	0
October-15	438	389	219	195	262	269	0	0
November-15	494	456	247	228	275	278	0	0
December-15	575	558	287	279	259	261	25	25
January-16	614	595	307	298	273	267	25	25
February-16	600	574	300	287	258	266	50	25
March-16	469	454	235	227	264	284	0	0
April-16	418	392	209	196	279	279	0	0
May-16	424	395	212	198	259	265	0	0

Table 7-7 Ameren Procurement, Delivery Year + 2 (2016-2017), (To Be Conducted Mid-April 2014 Based on the March 2014 Expected Load Forecast, Including Approved Energy Efficiency Programs)

	Expected Load (MW)		25% of Expected Load (MW)		Current Contracted Supply (MW)		Required Mid-April 2014 Purchases (MW)	
	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak
June-16	568	530	142	132	27	34	125	100
July-16	708	603	177	151	20	24	150	125
August-16	679	565	170	141	18	33	150	100
September-16	503	434	126	108	27	32	100	75
October-16	404	384	101	96	50	50	50	50
November-16	467	436	117	109	54	62	75	50
December-16	549	531	137	133	47	44	100	100
January-17	585	567	146	142	52	52	100	100
February-17	576	529	144	132	46	50	100	75
March-17	465	424	116	106	48	64	75	50
April-17	404	369	101	92	63	57	50	25
May-17	424	354	106	89	42	51	75	50

7.3.1.2 Delivery Year + 3 and Delivery Year + 4 (2017-2018 and 2018-2019)

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 2014 – 2017

Table 7-8 ComEd Procurement, Delivery Year 2014-2015, (To Be Conducted Mid-April 2014 Based on the March 2014 Expected Load Forecast, Including Approved Energy Efficiency Programs)

	Expected Load (MW)		106% (June-Oct) or 75% (Nov-May) of Expected Load (MW)		Current Contracted Supply (MW)		Required Mid-April 2014 Purchases (MW)	
	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak
June-14	1,570	1,238	1,664	1,312	676	535	1,000	775
July-14	1,851	1,442	1,962	1,529	797	617	1,175	900
August-14	1,732	1,361	1,836	1,443	703	581	1,125	850
September-14	1,363	1,072	1,445	1,136	520	534	925	600
October-14	1,184	945	1,255	1,002	571	595	675	400
November-14	1,282	1,070	962	803	608	601	350	200
December-14	1,477	1,249	1,108	937	669	572	450	375
January-15	1,474	1,260	1,106	945	688	589	425	350
February-15	1,377	1,172	1,033	879	622	584	400	300
March-15	1,229	1,035	922	776	583	612	350	175
April-15	1,104	909	828	682	601	615	225	75
May-15	1,135	928	851	696	616	575	225	125

Table 7-9 ComEd Procurement, Nov-May of Delivery Year 2014-2015, (To Be Conducted Mid-Sept 2014 Based on the July 2014 Expected Load Forecast, Including Approved Energy Efficiency Programs)

	Expected Load (MW)		100% of Expected Load (MW)		Anticipated Contracted Supply (MW)*		Required Mid-Sept 2014 Purchases (MW)	
	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak
November-14	1,282	1,070	1,282	1,070	958	801	325	275
December-14	1,477	1,249	1,477	1,249	1,119	947	350	300
January-15	1,474	1,260	1,474	1,260	1,113	939	350	325
February-15	1,377	1,172	1,377	1,172	1,022	884	350	300
March-15	1,229	1,035	1,229	1,035	933	787	300	250
April-15	1,104	909	1,104	909	826	690	275	225
May-15	1,135	928	1,135	928	841	700	300	225

*Including any purchases made in mid-April

Table 7-10 ComEd Procurement, Delivery Year +1 (2015-2016), (To Be Conducted Mid-April 2014 Based on the March 2014 Expected Load Forecast, Including Approved Energy Efficiency Programs)

	Expected Load (MW)		50% of Expected Load (MW)		Current Contracted Supply (MW)		Required Mid-April 2014 Purchases (MW)	
	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Peak
June-15	1,477	1,165	739	583	526	536	200	50
July-15	1,749	1,362	875	681	498	517	375	175
August-15	1,639	1,297	820	649	504	532	325	125
September-15	1,286	1,013	643	507	521	535	125	0
October-15	1,113	895	557	448	572	596	0	0
November-15	1,218	1,015	609	508	610	603	0	0
December-15	1,408	1,187	704	594	570	574	125	25
January-16	1,406	1,200	703	600	590	591	125	0
February-16	1,323	1,120	662	560	574	586	100	0
March-16	1,181	994	591	497	585	614	0	0
April-16	1,057	875	529	438	603	617	0	0
May-16	1,103	893	552	447	617	577	0	0

Table 7-11 ComEd Procurement, Delivery Year + 2 (2016-2017), (To Be Conducted Mid-April 2014 Based on the March 2014 Expected Load Forecast, Including Approved Energy Efficiency Programs)

	Expected Load MW		25% of Expected Load MW		Current Contracted Supply (MW)		Required Mid-April 2014 Purchases (MW)	
	Peak	Off-Peak	Peak	Off-Peak	Peak	Off-Pea k	Peak	Off-Peak
June-16	1,451	1,126	363	282	525	534	0	0
July-16	1,723	1,357	431	339	497	516	0	0
August-16	1,630	1,258	408	315	502	530	0	0
September-16	1,259	1,006	315	252	519	533	0	0
October-16	1,098	883	275	221	569	593	0	0
November-16	1,214	1,007	304	252	606	599	0	0
December-16	1,405	1,185	351	296	567	570	0	0
January-17	1,407	1,200	352	300	586	587	0	0
February-17	1,316	1,119	329	280	570	582	0	0
March-17	1,178	993	295	248	582	610	0	0
April-17	1,054	870	264	218	599	612	0	0
May-17	1,107	888	277	222	613	574	0	0

7.3.2.2 Delivery Year + 3 and Delivery Year + 4 (2017-2018 and 2018-2019)

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

Both Ameren and ComEd have been purchasing their ancillary services and transmission services from their respective RTOs, MISO and PJM. The utilities have also been managing their FTRs and ARRs 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

The IPA concludes that it does not need to include any extraordinary measures in the 2014 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. In case of any excess capacity credits PJM subsequently issues to ComEd, the IPA suggests ComEd sell its excess capacity credits and return the corresponding proceeds to its customers.

The 2013 Procurement Plan recommended retaining the 100%/70%/35% hedging strategy for purposes of Ameren's capacity requirements until such time as MISO demonstrates a robust FERC-approved capacity auction. Table 7-12 shows how much capacity that strategy would require Ameren to procure, based on the July 2013 forecast.

Table 7-12 Ameren Estimated Capacity Requirements Expected Case Forecast

Delivery Year	Peak Load + Losses + Reserves	Capacity Required	2012 Purchase	Remaining Need
2014-2015	1,283	1,290	1,110	180
2015-2016	1,169	820	0	820
2016-2017	1,116	400	0	400
2017-2018	1,064	0	0	1,064
2018-2019	1,014	0	0	1,014

In 2013, MISO's first annual capacity auction cleared the entire capacity requirement and the 2014 auction should have the liquidity to supply the 180 MW Ameren will need. The IPA expects that auction to demonstrate sufficient liquidity that it will be unnecessary to purchase capacity for 2015-2017 bilaterally. The Agency therefore recommends there be no capacity procurement event in 2014. However, the IPA is also aware that MISO has a prompt year capacity auction whereas PJM has a three year forward capacity auction. If Ameren were to rely entirely on the prompt year capacity auction in perpetuity (with no bilateral procurements via the IPA), it could increase the chances that Ameren's eligible retail customers would be exposed to a scarcity pricing event whereby capacity prices rise abruptly and dramatically. The IPA therefore recommends that the procurement of bilateral capacity for Ameren be revisited in future Plans in the absence of a more robust forward looking MISO capacity auction.

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.*

The energy efficiency and demand response programs for the three year period starting June of 2014 for Ameren and ComEd pursuant to Section 8-103 have not yet been filed, let alone approved by the ICC, so the IPA does not have concrete information regarding how the utilities will meet their demand response goals.

ComEd provided information regarding its existing demand response programs for 2012 which include:

- Direct Load Control ("DLC"): ComEd's residential central air conditioning cycling program is a DLC program with 71,900 customers with a load reduction potential of 87 MW (ComEd Rider AC).
- Voluntary Load Reduction ("VLR") Program: VLR is an energy-based demand response program, providing compensation based on the value of energy as determined by the real-time hourly market run by PJM. This program also provides for transmission and distribution ("T&D") compensation based on the local conditions of the T&D network. This portion of the portfolio has roughly 1,010 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 recently 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 recently sold 35 MW of capacity from the program into the PJM capacity auction for the 2016 Planning Year.

Ameren has a Voltage Optimization Pilot Program underway, offers the Power Smart Pricing real-time pricing program to residential customers, and has a proceeding underway before the Commission to approve a Peak Time Rebate program.

The IPA does not propose any additional demand response programs for the 2014-2015 delivery year. Peak Time Rebate (or Savings) programs create value through reduction in capacity charges. Given that the IPA has recommended that the utilities directly contract for capacity, the IPA does not have a direct role in the use of demand response to reduce capacity obligations. However, 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. With the ComEd Peak Time Savings program scheduled to commence in 2015, and the likely start-up of a similar program for Ameren, in 2016 the IPA invites stakeholders to provide comments to the IPA on how the Procurement Plan should include additional or complimentary demand response, and whether the roll-out of smart meters affects the timeline for additional programs.

7.6 Clean Coal

The IPA did not receive any requests for Clean Coal projects pursuant to Sections 1-58 or 1-75.

7.7 Summary of Strategy for the 2014 Procurement Plan

Table 7-13 summarizes the recommendations of this Chapter.

Table 7-13 Summary of 2014 Illinois Power Agency Procurement Plan Recommendations

	Delivery Year	Energy	Capacity	Renewable Resources	Ancillary Services
AMEREN	**2014-15**	Up to 175MW forecasted requirement (April Procurement)	Direct purchase from MISO capacity market	No RPS procurement: target exceeded (except solar and DG), budget cap exceeded	Will be purchased from MISO
AMEREN	**2015-16**	Up to 150MW forecasted requirement (April Procurement)	Direct purchase from MISO capacity market	No RPS procurement: target exceeded (except for solar and DG) and budget cap exceeded	Will be purchased from MISO
AMEREN	**2016-17**	Up to 150MW forecasted requirement (April Procurement)	Direct purchase from MISO capacity market	No RPS procurement: target exceeded (except for solar and DG) and budget cap exceeded	Will be purchased from MISO
AMEREN	**2017-18**	No energy procurement required	Direct purchase from MISO capacity market	No RPS procurement: target exceeded (except for solar and DG) and budget cap exceeded	Will be purchased from MISO
	2018-19	No energy procurement required	Direct purchase from MISO capacity market	Shortage of 10GWh but budget cap exceeded: no RPS procurement	Will be purchased from MISO
COMED	**2014-15**	Up to 1,175MW forecasted requirement (April Procurement) Up to 350MW additional forecasted requirement (September Procurement)	Direct purchase from PJM capacity market	Shortage of 116GWh but budget cap exceeded: no RPS procurement	Will be purchased from PJM
COMED	**2015-16**	Up to 375MW forecasted requirement (April Procurement)	Direct purchase from PJM capacity market	No RPS procurement: target met and budget cap exceeded	Will be purchased from PJM
COMED	**2016-17**	No energy procurement required	Direct purchase from PJM capacity market	No RPS procurement: target met and budget cap exceeded	Will be purchased from PJM
COMED	**2017-18**	No energy procurement required	Direct purchase from PJM capacity market	No RPS procurement: target met and budget cap exceeded	Will be purchased from PJM
COMED	**2018-19**	No energy procurement required	Direct purchase from PJM capacity market	Shortage of 178GWh but budget cap exceeded: no RPS procurement	Will be purchased from PJM

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"). 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.

From 2009 through 2012, the IPA's annual electricity procurement plans included purchase of renewable energy resources sufficient to meet the RPS applicable to the eligible load of ComEd and Ameren. In 2013, the IPA determined that resources under contract were sufficient to meet the reduced eligible load. The RPS calls for the procurement of the following quantity of renewable energy resources and renewable energy credits as a mandatory part of each utility's annual supply: [113]

- At least 2% by June 1, 2008
- At least 4% by June 1, 2009
- At least 5% by June 1, 2010
- At least 6% by June 1, 2011
- At least 7% by June 1, 2012
- At least 8% by June 1, 2013
- At least 9% by June 1, 2014
- At least 10% by June 1, 2015

This obligation increases by at least 1.5% each year thereafter to at least 25% by June 1, 2025. [114] The obligation of each electric utility is determined by applying the required percentage to the amount of eligible retail sales from the most recently completed delivery year. In addition, the RPS mandate includes targets for specific resource types: wind, photovoltaics (PV) and distributed generation (DG). [115]

The cap on the available RPS budget 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.*[116]

This section assesses the renewable resource volume and dollar budgets available for use to both utilities. The assumptions made below reflect the utility's expected load forecasts as described in Sections 3.2 and 3.3 and recommended by the IPA to be adopted by the ICC. If the ICC were to adopt a different load forecast, then the following analysis would have to be revised accordingly. Likewise, in a future delivery year the load forecast may be updated and differ significantly from what is shown here.

The IPA does not recommend procuring any additional renewable resources on behalf of Ameren or ComEd during the planning horizon. Furthermore, the IPA recommends (see Section 8.2.1) that the ICC order the utilities to produce updated load forecasts in March and to curtail the Long-Term Power Purchase

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[113] 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.

[114] 20 ILCS 3855/1-75(2)(c)(1).

[115] 20 ILCS 3855/1-75(c)(1).

[116] 20 ILCS 3855/1-75(2)(c)(2)(E).

Agreements ("LTPPAs") if the updated forecast indicates the renewable budget will be exceeded. These forecasts will also be used to plan the Mid-April 2014 forward hedge procurement event (see Sections 7.2.1 and 7.2.3).

8.1 Current Utility Renewable Resource Supply and Procurement

8.1.1 Ameren

As shown in Table 8-1, Ameren's current renewable contracts will cover its RPS targets for the next four Delivery Years. Assuming that no additional purchases of renewable energy are made, Ameren will fall short of meeting its RPS requirements in the 2018-2019 delivery year by less than 2%.

The Illinois Power Agency Act also sets separate goals for wind, photovoltaic and distributed renewable generation as fractions of the total renewables requirement.[117] Table 8-1 shows that Ameren is projected to meet its wind generation goals for the next five delivery years, but, assuming that no additional purchases of PV and DG are made, Ameren will fall short of the photovoltaic and distributed generation goals in each year. Ameren is also projected to exceed its spending cap on renewables (Table 8-3). As a consequence the IPA does not recommend procuring any additional renewable resources on behalf of Ameren during the planning horizon nor does the IPA recommends the sale of any renewable resources that exceed targets.

Table 8-1 Ameren's Existing RPS Contracts vs. RPS Requirements

Delivery Year		Total Renewables	Wind	Photo-voltaics	Distributed Generation
2014-15	**Target (MWh)**	949,030	711,773	28,471	7,118
	Purchased MWh	1,025,366	949,672	8,694	0
	Remaining Target (MWh)	-76,336	-237,899	19,777	7,118
2015-16	**Target (MWh)**	540,550	405,412	32,433	5,405
	Purchased MWh	1,008,810	979,916	8,894	0
	Remaining Target (MWh)	-468,260	-574,504	23,539	5,405
2016-17	**Target (MWh)**	544,472	408,354	32,668	5,445
	Purchased MWh	1,029,245	976,851	12,394	0
	Remaining Target (MWh)	-484,773	-568,497	20,274	5,445
2017-18	**Target (MWh)**	572,930	429,697	34,376	5,729
	Purchased MWh	854,396	848,338	6,058	0
	Remaining Target (MWh)	-281,466	-418,641	28,318	5,729
2018-19	**Target (MWh)**	607,991	455,993	36,479	6,080
	Purchased MWh	600,000	596,571	3,429	0
	Remaining Target (MWh)	7,991	-140,578	33,050	6,080

8.1.2 ComEd

Table 8-2 shows ComEd's current RPS contracts relative to its renewables requirements. ComEd's forecast indicates that it has a relatively small shortage of 116GWH of renewables for the 2014-2015 delivery year. However, ComEd expects to exceed the renewables cost cap (Table 8-4) and therefore cannot procure any additional renewables. Based on current forecasts, ComEd will meet its RPS requirement, with comfortable surpluses, in the next three years.

The IPA does not recommend procuring additional renewable resources on behalf of ComEd during the planning horizon.

[117] 20 ILCS 3855/1-75(2)(c)(1).

Table 8-2 ComEd's Existing RPS Contracts vs. RPS Requirements

	Total Renewables			Other Targets (MWh)		
Delivery Year	**Target (MWh)**	**Purchased MWh**	**Remaining Target (MWh)**	**Wind**	**Photo-voltaics**	**Distributed Generation**
2014-15	2,001,744	1,885,302	116,442	1,501,308	60,052	15,013
2015-16	1,171,086	1,464,204	(293,118)	878,315	70,265	11,711
2016-17	1,198,607	1,561,397	(362,790)	898,955	71,916	11,986
2017-18	1,300,312	1,533,198	(232,886)	975,234	78,019	13,003
2018-19	1,439,620	1,261,725	177,895	1,079,715	86,377	14,396

Table 8-2 includes ComEd's statutory targets for wind, photovoltaic and distributed renewable procurement over the five-year projection horizon. The rate cap described above prevents procurement of these or any other resources on behalf of eligible retail customers as long as the cap is exceeded.

Note that the significant decrease in RPS target observed between Delivery Years 2014-2015 and 2015-2016 reflects the drop in eligible load that occurred between Delivery Years 2012-2013 and 2013-2014. The statutory RPS obligations of Ameren and ComEd are determined by their amount of actual eligible retail sales two years earlier.

8.2 LTPPA Curtailment

8.2.1 Impact of Budget Cap

As noted above, the Illinois Power Act includes a limit on each utility's spending on renewable procurement. For the 2013-2014 delivery year, the ICC approved the curtailment of Ameren's and ComEd's existing long-term renewables contracts to keep the cost of renewable energy resource under the statutory cap. This approval was subject to the March 2013 forecast indicating the renewable budget was exceeded.[118] Since ComEd's March 2013 forecast indicated that its budget was exceeded and Ameren's was not, ComEd initiated curtailments whereas Ameren did not (Ameren's current forecast suggests they will be obliged to curtail in the coming years). This section addresses the utilities' committed RPS contracts relative to the spending cap and possible curtailment for the 2014-2015 and subsequent delivery years.

Table 8-3 Required Reductions (Curtailments) of Long-term Renewable Contracts (LTPPAs) to Meet IPA Act Spending Cap, Ameren

Delivery Year	Contractual REC Cost ($)	Delivery Year RPS Budget ($)	Reduction Required ($)	Contractual REC Cost, LTPPAs ($)	LTPPA Quantity Reduction (%)
2014-15	9,167,145	8,547,742	619,403	8,155,000	7.6%
2015-16	9,183,529	7,956,671	1,226,858	7,826,000	15.7%
2016-17	10,403,861	7,570,119	2,833,742	7,796,000	36.3%
2017-18	9,412,155	7,216,201	2,195,954	7,957,000	27.6%
2018-19	8,000,000	6,860,913	1,139,087	8,000,000	14.2%

Table 8-3 indicates that under its current RPS contracts and given the expected load forecast, Ameren is anticipated to exceed the IPA Act spending cap in every year of the five-year projection horizon.

118 ICC Docket No. 12-0544, Final Order dated December 19, 2012 at 110, 67-68.

Table 8-4 Required Reductions (Curtailments) of Long-Term Renewable Contracts (LTPPAs) to Meet IPA Act Spending Cap, ComEd

Delivery Year	Contractual REC Cost ($)	Delivery Year RPS Budget ($)	Reduction Required ($)	Contractual REC Cost, LTPPAs ($)	LTPPA Quantity Reduction (%)
2014-15	24,272,678	19,716,565	4,556,113	23,189,000	19.6%
2015-16	23,159,931	18,921,538	4,238,393	22,613,000	18.7%
2016-17	23,483,757	18,781,575	4,702,182	22,676,000	20.7%
2017-18	23,776,890	18,875,753	4,901,136	23,139,000	21.2%
2018-19	23,415,145	18,980,868	4,434,278	23,358,000	19.0%

Table 8-4, which is similar to Table 8-3, shows ComEd's contractual RPS supplies and cost relative to the cost cap, given the expected load forecast. Like Ameren, ComEd is anticipated to exceed the IPA Act spending cap in every year of the five-year projection horizon – as it did in the current delivery year, forcing curtailment of ComEd's LTPPAs.

The spending caps will prevent ComEd and Ameren from committing any additional money to procure renewables for the 2014-2015 delivery year, including specific procurements of wind, photovoltaic and distributed renewables. As noted above, in future years if the load forecast is significantly different, then these caps may cease to apply. But for the purposes of this plan, the spending caps clearly preclude the procurement of renewable energy resources in 2014.

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 cap. Therefore, the purchases under the long term renewable contracts will need to be reduced as shown in the tables above. An estimate of the overall amount is shown in this Plan for both Ameren and ComEd, however the exact amount is uncertain at this time. Both utilities will be submitting updated forecasts in March 2014. Once the Commission has approved this Plan, including the incremental energy efficiency program amounts, and the utilities have submitted further updated forecasts in March 2014 to reflect municipal aggregation activity and any Commission-approved energy efficiency programs, each utility should calculate both the overall amount of the necessary reduction to keep the purchases under the statutory cap, and determine the amount that each long term renewable contract will need to be reduced. Any such reductions should be applied proportionately to the long term renewable contracts consistent with the terms of the contracts. This calculation should only be made for the 2014-15 delivery year. Future procurement plans will address the need, if any, for additional reductions.

The updated March 2014 forecast and related calculations of the curtailments (if any) should be submitted to both the IPA and the Commission Staff for their review and acceptance. Once the utilities have received written acceptance from both the IPA and the Commission Staff, the utilities may then notify the suppliers under the long-term renewable contracts of the amounts of the reductions. The suppliers will then make the election allowed them under the agreements. Because the reductions under the IPA Act are to be made on the basis of the "estimated" net increase in charges to Eligible Retail Customers, no further reductions in purchases of renewable under the long-term contracts for delivery year 2014-2015 will be made based on either the suppliers' elections or the actual increases in charges experienced by Eligible Retail Customers during the 2014-2015 delivery year.

As the ICC ordered in its approval of the 2013 Procurement Plan, the IPA recommends March 2014 updates to both utilities' load forecasts. These forecasts will form the basis for curtailment upon consensus of the utilities, IPA, ICC Staff, Procurement Administrator(s) and Procurement Monitor. To the extent that the ICC authorizes block energy procurements for ComEd (as recommended in Chapter 7 above) or Ameren, the IPA notes that additional load forecasts will be required in anticipation of the procurement event and the load forecast should not be duplicated. As with Ameren's March 2013 load forecast, one or both of the utilities may have unanticipated changes in their respective load forecasts from the previous forecasts such that curtailments are not warranted.

8.3 Alternative Compliance Payments

8.3.1 Use of Hourly ACPs Held by the Utilities

As described in Chapter 2, the utilities collect Alternative Compliance Payments ("ACPs") on behalf of customers taking hourly service from the utility[119]. Unlike the ACP funds paid by ARES into the RERF and discussed in Section 8.3.2 below, the utility hourly customer ACP funds are held by the utilities[120]. As required by the IPA Act, each utility has disclosed the amount of hourly customer ACP funds being held; for Ameren, the value is $1,800,484; for ComEd, the value is $4,099,937.

The IPA Act requires the ACP funds from utility hourly customers 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."[121] In the ICC's Final Order in the 2013 Procurement Plan approval docket, the ICC accepted the IPA's proposal that the utility hourly customer ACP funds should be used to purchase curtailed RECs at the imputed REC price.[122] As approved by the Commission in Docket No. 09-0373, the imputed REC price under the bundled renewable contracts is equal to the difference between the Contract Price and the forward price curve for each respective load zone for a particular year, as developed by the Procurement Administrator in 2010.[123]

During the pendency of the approval docket for the 2013 Procurement Plan, the IPA and several stakeholders anticipated that the LTPPA contracts entered into by both Ameren and ComEd could face curtailment. In the end, only ComEd implemented an ICC-approved curtailment.[124]

In the event that the Commission approves curtailments based on March 2014 load forecasts, and after consensus of the aforementioned parties then the IPA recommends that the Commission once again approve use of the utility hourly customer ACPs to purchase curtailed RECs at the imputed REC price. While several parties argued that using these funds could be counter to the statute and could be construed as a supplier subsidy by utility hourly priced customers, the Commission agreed with the IPA that this was an appropriate use of such funds and the IPA again asks for the same approval in this Plan. If, due to load shifts or change in law, the ICC does not approve curtailments and does approve additional procurements, then the IPA recommends that the Commission authorize the IPA to use those funds to supplement any renewable resource procurements.

If the ICC approves procurements of multiple renewable resource products for a single utility, then the IPA respectfully requests that the ICC authorize use of the utility hourly customer ACP funds to the highest renewable resource procurement priority.

8.3.2 Use of ACPs Held by the IPA

As of this report date, the RERF balance equals $14,911,284.40, the total amount received in the Agency's RERF attributable to ARES ACP payments. Table 8-5, below, shows the current IPA RERF balance sheet. In September 2013, the IPA expects to receive an estimated $40 million in ACPs for the June 2012 – May 2013 planning year. These expected payments, in the aggregate, are significantly higher than prior year payments. The higher amount is a direct result of significant load switching from utility supply to RES supply in recent months, primarily driven by municipal aggregation activities.

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[119] *See* 20 ILCS 3855/1-75(c)(5).
[120] See id.
[121] Id.
[122] *See* ICC Docket No. 12-0544, Final Order dated December 19, 2012 at 110-111, 114-115.
[123] *See* Appendix K (pp. 2-3) to IPA's Load Forecast for Five-Year Planning Period June 2010 – May 2015, as approved by the Commission in Docket No. 09-0373.
[124] *See, e.g.*, *id.* at 110 (noting likelihood of Ameren curtailment based on Ameren's November 2012 load forecast).

Table 8-5 RERF Balance

Planning Year	Funds Received	Total ACPs
2009-10	2010 - Quarters 3 and 4	$7,148,261.61
2010-11	2011 - Quarters 3 and 4	$5,606,245.18
2011-12	2012 - Quarters 3 and 4	$2,156,777.61
Aggregate Total		**$ 14,911,284.40**

The ICC has held that it does not have jurisdiction over the RERF, and as a result the IPA is not seeking approval for procurement using the RERF.[125] However, for informational purposes, the IPA believes it would be beneficial to explain its plans for spending the RERF and allow the ICC and stakeholders to coordinate the ICC jurisdictional Procurement Plan spending with the IPA's RERF spending.

As the IPA noted in the 2013 Procurement Plan docket, the IPA faces statutory and practical barriers to spending the RERF absent a procurement event on behalf of eligible retail customers. The IPA has worked with stakeholders on the elements of a legislative solution to address the problems inherent in the statute as currently written. To briefly summarize, Section 1-56 of the IPA Act authorizes spending of the RERF on the same products procured for utility customers at the same or lesser price. In the absence of a procurement event for eligible retail customers, there are no "same products" and no price target.[126] Furthermore, even if the IPA were to ignore these statutory requirements, the IPA does not have the statutory authority to recover the significant costs of a procurement (the statute apparently envisioned the RERF as an add-on to budget for a utility procurement) and does not have the authority to create an enforceable cost-based benchmark with the ICC.[127] As a result, absent a change in law to address these issues or a procurement on behalf of eligible retail customers, the IPA does not believe that it can spend the RERF on anything except curtailed RECs.

- If there are no changes in law and the ICC does not authorize renewable resource procurements on behalf of eligible retail customers, then the IPA will plan to spend some of the RERF funds on curtailed RECs on a one-year basis. The IPA is currently taking this action for RECs curtailed by ComEd in the current delivery year. In the current year, the IPA plans to purchase up to 121,620 curtailed RECs at a total expected cost of up to $2.24 million
- If there are no changes in law and the ICC does authorize renewable energy resource procurements on behalf of eligible retail customers, then the IPA will use some or all of the RERF to expand the budget for the procurements according to the IPA's highest product priorities
- If there are changes in law sufficient to allow the IPA to procure renewable energy resources at the IPA's discretion and not necessarily in conjunction with a utility procurement, then the IPA plans to spend funds from the RERF in accordance with the provisions of Section 1-56(b). In particular the IPA will seek to achieve the goals for procuring solar and distributed renewable energy resources. Section1-56(b) also specifies that 75% of resources procured come from wind. The IPA will analyze the quantities of wind procured via the purchase of curtailed RECs described above and will fill the balance of the requirement with RECs from existing wind energy facilities.

To the extent that the ICC authorizes a procurement event on behalf of eligible retail customers and the IPA also has discretion to procure renewable resources using the RERF, then the IPA plans to work with the ICC and stakeholders to ensure coordination between procurement events and products procured to minimize expenditure of resources and meet state renewable targets.

[125] ICC Docket No. 12-0544, Final Order dated December 19, 2012 at 112-114.
[126] *See* 20 ILCS 3855/1-56(c) and (d).
[127] *Compare* 20 ILCS 3855/1-56 *with* 20 ILCS 3855/1-75(g)-(h) (explicitly authorizing fee assessment and cost recovery) *and* 220 ILCS 5/16-111.5(e)(3) (explicitly setting out benchmark as price-not-to-exceed).

8.4 Changes in Law

In the draft plan for public comment released on August 15, 2013, the IPA set out a priority list for renewable resource procurement. As noted above, the load forecasts for Ameren and ComEd indicate that there will be a curtailment in the LTPPAs during the upcoming delivery year. As a corollary, the renewable resource budgets will be exceeded for each utility and thus no procurements will take place. Although the IPA continues to recommend the prioritization set forth in the August 15, 2013 public comment draft plan, the IPA will remove the discussion because potential statutory changes are insufficiently definite to provide a meaningful backdrop for discussion at this point in time.

9 Procurement Process Design

The procedural requirements for the procurement process are detailed in the Illinois Public Utilities Act at Section 16-111.5. The procurement administrators, retained by the Agency in accordance with 20 ILCS 3855/1-75(a)(2), conduct the competitive procurement events on behalf of the IPA. The costs of the procurement administrators incurred by the Illinois Power Agency are recovered from the bidders and suppliers that participate in the competitive solicitations, through both Bid Participation Fees and Supplier Fees assessed by the IPA. As a practical matter, the utility "eligible retail customers" 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 Agency and the procurement administrators have reviewed the process for 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, provide supply requirements, and otherwise explain the competitive procurement process. In addition to such other publication as the procurement administrator determines is appropriate, this information shall be posted on the Illinois Power Agency's and the Commission's websites. The procurement administrator shall also administer the prequalification process, including evaluation of credit worthiness, compliance with procurement rules, and agreement to the standard form contract developed pursuant to paragraph (2) of this subsection (e). The procurement administrator shall then identify and register bidders to participate in the procurement event.*

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

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

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

> *As part of the development of the procurement process, the procurement administrator, in consultation with the Commission staff, Agency staff, and the procurement monitor, shall 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.*

Of these five process components, the area with the greatest potential for efficiency improvements resulting in lower costs passed along to ratepayers is item (2): development of standard contract forms and credit terms and instruments. The IPA believes that the forms can be further standardized while remaining acceptable to future potential bidders, thus reducing procurement administrator time and billable hours, while shortening the critical path time needed to conduct a procurement event. This is because the forms, terms and instruments have become relatively stable, with fewer comments being received from potential bidders requesting revision or optional terms for each succeeding procurement event. The IPA also notes that the contracts with the incumbent procurement administrators have expired and the IPA will be conducting a competitive procurement process for a new procurement administrator starting this fall. There may be additional cost savings to be realized by having a single procurement administrator rather than a different administrator for each utility.

Any procurement process to be conducted under the auspices of the 2014 Procurement Plan would be the seventh iteration of IPA-run procurements, when including the February 2012 Rate Stability procurements and the December 2010 long-term REC and energy procurement. In each of the prior iterations, potential bidders have 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 two procurements conducted in 2012 (the Rate Stability Procurement and the standard Spring 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 procurements). The documents used for the 2012 IPA-run procurements 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 of the utilities, utility customers and suppliers. The IPA therefore recommends that the energy contracts used in the February 2012 Rate Stability procurements be the starting point for the contracts used in the energy procurements associated with this plan.

The IPA plans to work with the Procurement Administrator, the Procurement Monitor, the Commission and other stakeholder to implement additional procurement process improvements suggested in comments that may include the following:

- Schedule procurements for the early part of the week. Energy markets are more volatile for a period of time prior to and after the gas storage numbers come out every Thursday.
- Reduce the length of time between submission of bids and notification of likely bid award to the greatest extent possible decreases the risk that suppliers bear, which would likely lead to lower overall bid prices.
- Hold REC procurements within days of the energy procurements to expedite the release of tariff changes resulting from these procurements. Delays in the release of the tariffs and charges cause substantial confusion and potential competitive harm in the retail market.

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.*

There have been no procurements in 2013, therefore no informal comment process was conducted this year. Comments from previous informal hearings are available of the Commission's web site.

Appendices

Appendix A. Regulatory Compliance Index

Available as a separate file at: http://www2.illinois.gov/ipa/Pages/FiledPlanAppendices2014.aspx

Appendix B. Ameren Load Forecast Documents

Available as separate files at: http://www2.illinois.gov/ipa/Pages/FiledPlanAppendices2014.aspx

Supplemental Documents

- Section 16-111.5B Submittal (includes Appendices 1 and 3. Appendices 6 and 7 have been marked "Confidential")
- Appendix 2: Workshop Summary
- Appendix 4: AIC Potential Study
  - Volume 1: Executive Summary
  - Volume 2: Market Research
  - Volume 3: EE Potential Analysis
  - Volume 4: Program Analysis
  - Volume 5: Supply Curves
- Appendix 5: AIC Third Party RFP

Appendix C. ComEd Load Forecast Document

Available as separate files at: http://www2.illinois.gov/ipa/Pages/FiledPlanAppendices2014.aspx

Supplemental Documents

- Appendix C-1: Potential Study
- Appendix C-2: Energy Efficiency Analysis Summary
- Appendix C-3: Monthly Savings Curves
- Appendix C-4: Program Details
- ComEd 2013 Third Party Efficiency Program Summary of Vendor Scoring Process, July 5, 2013 (Marked “Confidential”)

Appendix D. Ameren Load Forecast and Supply Portfolio by Scenario

Available as a separate file at: http://www2.illinois.gov/ipa/Pages/FiledPlanAppendices2014.aspx

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D.2 Ameren Bundled Service Load Forecast

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Appendix E. ComEd Load Forecast and Supply Portfolio by Scenario

Available as a separate file at: http://www2.illinois.gov/ipa/Pages/FiledPlanAppendices2014.aspx

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Appendix F. Description of Monte Carlo Model

Available as a separate file at: http://www2.illinois.gov/ipa/Pages/FiledPlanAppendices2014.aspx

Appendix G. Numerical Values of Purchased Energy Adjustments, in $/MWh

Available as a separate file at: http://www2.illinois.gov/ipa/Pages/FiledPlanAppendices2014.aspx

Appendix H. Department of Commerce and Economic Opportunity Section 16-111.5B Submittal

Available as a separate file at: http://www2.illinois.gov/ipa/Pages/FiledPlanAppendices2014.aspx