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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
2013 Electricity Procurement Plan

1.0 Executive Summary

A Transition Year

This is the fifth electricity and renewable resource procurement plan (the "Plan", "2013 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 2.0 of this plan describes the specific legislative authority and requirements to be included in any such plan. The Plan deals with the provision of electricity and renewable resource supply for the "eligible retail customers" of Ameren Illinois ("Ameren") and Commonwealth Edison ("ComEd"), generally residential and small commercial fixed price customers who have not chosen service from an alternate supplier, for a 5-year planning horizon that begins with the 2013-2014 delivery year and lasts through the 2017-2018 delivery year.

Despite the fact that several plans precede this one, this plan is not to be mistaken as a *pro forma* exercise in regulatory compliance. Illinois began its successful journey down the road of deregulated competitive markets for retail electricity supply in December 1997 with a competitive transition period that lasted through 2006. Since 2006, retail competitive markets have continued to flourish, with recent advances fostered by wide-spread municipal aggregation efforts. More recently, both ComEd and Ameren have experienced dramatic reductions in retail load serving obligations since the overwhelmingly successful March 2012 referenda authorizing opt-out aggregation of customers and the consequent opportunities for substantial savings on the supply portion of customers' bills. The utility load forecasts which underpin this supply procurement plan project significantly lower utility loads than did prior plans. These load forecasts are described in Section 3.0 of this Plan.

On the supply side, both Ameren and ComEd have a pre-existing portfolio of supply already procured and under contract. Section 4.0 of this Plan describes the nature of the pre-existing portfolio, which was designed to achieve low cost, reliable service and price stability over time. As this Section illustrates, however, the portfolio of pre-existing supply was procured without the benefit of witnessing the dramatic shift residential and small commercial customers have made to exploring competitive retail markets, at least as they exist today in Illinois. Therefore, particularly for the 2013-14 delivery year, there is significant apparent oversupply in the base case forecast.

Given the unprecedented (in Illinois) load shift, there is a need to recalibrate the supply and demand balance point for the retail electricity customers served by this Plan. The 2013-14 delivery year is the transition year in which the oversupply of current contracts winds down; and the utility supply portfolios can then start with a "clean slate" going forward. That is not to say that the IPA, stakeholders, or the Commission may assume that the utility load serving requirements are permanently altered to a lower level. Constant vigilance and analysis, and prudent risk management strategies must be maintained. The annual filing of IPA Procurement Plans allows for future adjustments to be made. Fortunately, Illinois retail electricity customers have the benefit of strong regional transmission organizations, PJM and MISO, which further assure supply reliability, transparent wholesale prices, and capacity, energy and ancillary service products designed to provide appropriate risk management tools. Section 5.0 of this Plan describes the MISO and PJM resource adequacy outlook and Section 6.0 discusses the current wholesale market outlook and risk management tools available to assure a responsible approach to portfolio management.

The Action Plan

The analysis of procurement options in this Plan, contained in Section 7.0, concludes that there is little in terms of electricity supply resources to be purchased in the 2013 Procurement Process. This holds true, as well, for renewable resources, which are discussed and analyzed in Section 8.0. A large part of the existing renewable resource portfolio for both utilities consists of pre-existing 20-year contracts executed in 2010. Payments under these contracts are forecasted to exceed the legislatively-mandated price caps for renewable resources for some or all of the delivery years in the planning horizon. Therefore, this Plan proposes to curtail purchases under those contracts in order to keep the purchase of renewables under the spending cap. The IPA is considering using its Renewable Energy Resources Fund, funded by alternate compliance payments made by the ARES to comply with at least 50% of the RPS requirements and administered by the IPA pursuant to Section 1-56 of the IPA Act to help mitigate payment risk for these contracts. In addition, the IPA proposes to use the ACP payments that have been collected by Ameren and ComEd from their respective hourly-priced service customers to be collectively used as necessary to supplement payment to the suppliers to the extent such payment would exceed the individual utility renewable resource budget caps in a given year. At the appropriate time, the IPA commits to work with Ameren, ComEd and the long-term renewable resource suppliers to effect a practical way to make this work within the confines of the existing PUA and IPA Act.

Again, the annual nature of Procurement Plan filing allows for a constant revisiting of actions to be prudently taken, so that each successive plan year allows for appropriately-timed and cost-effective response to actual market conditions. Furthermore, the strength of the PJM and MISO marketplace allows this to be done with a high level of confidence.

In order to deal with the risk associated largely with retail customer migration, the Illinois Power Agency recommends that its former hedging strategy for energy products, designed to result in a ladder of products and predicated on a philosophy of being 100% hedged for the first year in the planning horizon, 70% hedged for the second and 35% hedged for the third, be replaced with one suggested by Commission Staff and supported as a general matter by the Commission's Procurement Monitor:

Energy Hedging Plan: Staff Proposal 1

Fixed Price Hedge Quantities, as a % of *Expected* Average Hourly Load For Each of the 24 Periods of the Indicated Plan Year, to Have Established by June 1 of the Current Plan Year		
Current PY	*Current PY+1*	*Current PY+2*
75%	*50%*	*25%*

The IPA notes that this recommendation was developed in a time frame characterized by declining market prices and accelerating customer switching. However, since no energy procurement is warranted in this Procurement Plan, next year's Procurement Plan will allow for additional analysis of this revised hedging strategy on volatility and expected cost.

The IPA recommends 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.

The table below summarizes the procurement recommendations contained in this Plan for both Ameren and ComEd. The IPA continues to recommend that ancillary services, load balancing services and transmission services (Network Integrated Transmission Service or NITS) be purchased, as they are now, by Ameren from the MISO marketplace and by ComEd from PJM. In addition, the IPA continues to recommend that each utility pursue Auction Revenue Rights (ARRs) in MISO or PJM. Ameren shall continue to actively participate in the MISO ARR nomination and allocation process as outlined and approved in prior Plans. ComEd shall similarly participate in the PJM nomination and allocation process as outlined and approved in prior Plans.

Summary of 2013 Illinois Power Agency Procurement Plan Recommendations						
	Ameren			ComEd		
Delivery Year	**Energy**	**Capacity**	**Renewable Resources**	**Energy**	**Capacity**	**Renewable Resources**
2013-14	No energy procurement required in 2013	Purchase remaining capacity resources requirement from the FERC-approved MISO capacity auction in 2013	Total volume targets already met < budget cap, no new resources required	No energy procurement required in 2013	Direct purchase from PJM capacity market	No new resources; supplement payment on long term contracts with ACP $ held by the IPA and utilities
2014-15	No energy procurement required in 2013	Already almost 70% hedged. Purchase remaining capacity resources requirement in 2014 using the MISO capacity auction.	Total volume targets already met < budget cap, no new resources required	No energy procurement required in 2013	Direct purchase from PJM capacity market	No new resources; supplement payment on long term contracts with ACP $ held by the IPA and utilities
2015-16	No energy procurement required in 2013	Defer procurement to 2014 Plan.	Total volume targets already met < budget cap, no new resources required	No energy procurement required in 2013	Direct purchase from PJM capacity market	No new resources; supplement payment on long term contracts with ACP $ held by the IPA and utilities
2016-17	No energy procurement required in 2013	TBD	No new resources; supplement payment on long term contracts with ACP $ held by the IPA	No energy procurement required in 2013	Direct purchase from PJM capacity market	No new resources; supplement payment on long term contracts with ACP $ held by the IPA and utilities
2017-18	No energy procurement required in 2013	TBD	No new resources; supplement payment on long term contracts with ACP $ held by the IPA	No energy procurement required in 2013	Direct purchase from PJM capacity market	No new resources; supplement payment on long term contracts with ACP $ held by the IPA and utilities

While there is little in terms of the purchase of traditional products, including renewable resource purchases, being recommended in this Plan, the Illinois Power Agency proposes the following Plan components in addition to the procurement action plan in the above table and requests the following Commission action:

1. Approve the ComEd and Ameren Load Forecasts;
2. Approve the curtailment of purchases of renewable resources under the long-term renewable resource contracts in order to keep the purchase of renewables under the statutory rate impact cap of 2.015%;
3. Approve the incremental energy efficiency programs as per the assessments by both Ameren and ComEd, as described and discussed in Section 7.1 of this Plan;
4. Approve the sourcing agreement between the FutureGen Alliance and the utilities and the ARES pursuant to Section 1-75(d)(5) of the Illinois Power Agency Act, as described

and discussed in Section 7.5 of this Plan, subject to any modifications made by the Commission;

5. Review the general parameters of a Distributed Generation program as described and discussed in Section 8.2 of this Plan, to be finalized in future utility DG offerings for eligible retail customers;
6. Reaffirm use of a blended imputed REC price contained within the bundled energy and REC prices associated with the long-term renewable contracts executed in 2010 as calculated and agreed upon by the Procurement Administrators, the IPA, Commission Staff and the Procurement Monitor, as being in the public interest and necessary to renewable resource procurement decisions in this and future Procurement Plans.

In addition, the IPA suggests that improvements be made to the Procurement Process as recommended in Section 9.0 of this Plan.

The Illinois Power Agency respectfully requests Commission approval of this Plan as contained herein and summarized above, and believes it to be compliant with all provisions of law and capable of the provision of adequate, reliable, affordable, efficient, and environmentally-sustainable electric service at the lowest, total cost over time, taking into account benefits of price stability.

2.0 Legislative/Regulatory Requirements of the Plan

This section of the 2013 Procurement Plan describes the legislative and regulatory requirements applicable to this Procurement Plan. A Regulatory Compliance Index, Appendix V, provides a complete cross index of regulatory/legislative requirements and the specific sections of this Plan that address each requirement identified.

IPA Authority

The IPA was established in 2007 by Public Act 95-0481 in order to ensure that customers, in particular customers in service classes that have not been declared competitive and who take service from the utility's bundled rate ("eligible retail customers"),[1] benefit from retail and wholesale competition, by improving the process to procure electricity for those customers.[2] 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."[3] The General Assembly also found that "investment in energy efficiency and demand-response measures, and to support development of clean coal technologies and renewable resources" furthered its stated goals.[4]

Each year, the Planning and Procurement Bureau of the IPA must develop a "power procurement plan" and conduct a competitive procurement process to procure supply resources as identified the final procurement plan, as approved pursuant to Section 16-111.5 of the Public Utilities Act ("PUA").[5] The purpose of the power procurement plan is to secure 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

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

[2] 20 ILCS 3855/1-5(2); 3855 /1-5(3); 3855/1-5(4).

[3] 20 ILCS 3855/1-5(1).

[4] 20 ILCS 3855/1-5(4)

[5] 20 ILCS 3855/1-20(a)(2), 3855/1-75(a).

("Ameren" or "AIC").[6] The Illinois Power Agency Act ("IPA Act") requires that the procurement plan be developed, and the competitive procurement process shall be conducted, by experts or expert consulting firms (the "procurement planning consultant" and "Procurement Administrator", respectively).[7] The Illinois Commerce Commission ("Commission") is tasked with approval of the plan and monitoring of the procurement events through a Commission-hired "Procurement Monitor."[8]

Procurement Plan Development and Approval Process

Although the procurement planning process is ongoing and incorporates party input and lessons from past proceedings, the statutory deadlines for the 2013 Procurement Plan begin on July 15, 2012. On that date, each Illinois utility that procures electricity through the IPA must submit a range of load forecasts. These forecasts – which form the backbone of the Procurement Plan and which are covered in Chapter 3 in greater detail – must cover the five-year procurement planning period for the next procurement plan, and include hourly data representing a high-load, low-load and expected load-scenario for the load of the eligible retail customers.

Next, the IPA prepares a draft Procurement Plan by August 15 for public comment. During the thirty-day comment period, the IPA holds at least one public hearing within each utility's service area for the purpose of receiving public comment on the procurement plan; for the 2013 Procurement Plan, the hearing dates are September 17, 2012 in Chicago and September 20, 2012 in Springfield. Within fourteen days following the end of the 30-day review period, the IPA files a revised Procurement Plan with the Commission for approval. Objections must be filed with the Commission within five days after the filing of the Plan.[9] The Commission must enter an order confirming or modifying the Plan within 90 days after it is filed by the IPA.

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.

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.[10] In addition, the Procurement Plan must analyze the impact of demand side and renewable energy initiatives, including the impact of demand response programs

[6] 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).)

[7] 20 ILCS 3855/1-75(a)(1), 3855/1-75(a)(2).

[8] 220 ILCS 5/16-111.5(b), (c)(2)

[9] 220 ILCS 5/16-111.5(d)(3).

[10] 220 ILCS 5/16-111.5(b)(1)(i)-(iv).

and energy efficiency programs, both current and projected.[11] 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,[12] 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.[13]
- 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.[14] 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.[15]
- 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.[16] For those portfolio measures that are identified as having significant price risk, the Plan shall identify alternatives to those measures.
- For load requirements included in the Plan, the Plan should include the proposed procedures for balancing loads, including the process for hourly load balancing of supply and demand and the criteria for portfolio re-balancing in the event of significant shifts in load.[17]
- Include renewable resource and demand-response products, as discussed below.

Renewable Portfolio Standard

The General Assembly has acknowledged the importance of including cost-effective renewable resources in a diverse electricity portfolio.[18] "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

[11] 220 ILCS 5/16-111.5(b)(2), (b)(2)(i).

[12] 220 ILCS 5/16-111.5(b)(3).

[13] 220 ILCS 5/16-111.5(b)(i), 220 ILCS 5/16-111.5(b)(iii).

[14] 220 ILCS 5/16-111.5(b)(3)(iv).

[15] 220 ILCS 5/16-111.5(b)(3)(v).

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

[17] 220 ILCS 5/16-111.5(b)(4).

[18] 20 ILCS 3855/1-5(5), 3855/1-5(6).

panels, biodiesel, and others as identified in the IPA Act.[19] 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, 2013, at least 8% of each utility's total supply should be generated from renewable energy resources.[20] For the current (2013) Procurement Plan, to the extent cost-effective resources are available, at least 75% of the renewable energy resources used to meet those standards shall come from wind generation, 1.5% shall come from photovoltaics, and 0.5% shall come from distributed renewable energy generation devices.[21] Renewable energy resources procured from distributed generation devices to meet this requirement may also count towards the required percentages for wind and solar photovoltaics.[22]

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 kilowatthour by eligible retail customers during the year ending May 31, 2007; or
- The incremental amount per kilowatthour paid for these resources in 2011.[23]

In addition to the funds available from eligible retail customers, the IPA also has available the amounts collected by the utility from customers taking service under the utility's hourly pricing tariff or tariffs under the alternative compliance payment rate or rates in the prior year ending May 31.[24]

Finally, 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.[25] 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.[26]

Distributed Generation Resources Standard

Effective beginning in the 2013 Procurement Plan, a distributed generation resource requirement was added by the Legislature. 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.[27]

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[19] 20 ILCS 3855/1-10.

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

[21] *Id.*

[22] 20 ILCS 3866/1-75(c)(1)

[23] 20 ILCS 3855/1-75(c)(2)(E).

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

[25] 20 ILCS 3855/1-75(c)(3).

[26] *Id.*

[27] 20 ILCS 3855/1-75(c)(1).

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.[28]

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,[29]

In the ICC 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 distributed generation renewable resource procurement plan.[30] Those workshops were held. The IPA 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.[31] In Section 8.2 the Procurement Plan discusses in much more detail the process for procuring distributed energy resources.

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' ICC-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 Act, 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.

The PUA requires the Agency to include in its Procurement Plan energy efficiency programs and measures that it determines are cost-effective and the associated energy savings shall be

[28] 20 ILCS 3855/1-10.

[29] *Id.*

[30] Final Order in 11-0660 at 117.

[31] http://www2.illinois.gov/ipa/Pages/CurrentEvents.aspx.

factored into the resource solicitation process. 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.* [32]

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."[33] 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.[34] 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[35];
- 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.[36]; 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.[37]

[32] 20 ILCS 3855/1-10

[33] 220 ILCS 5/16-111.5(b)(3)(ii).

[34] 220 ILCS 5/16-111.5(b)(3)(ii).

[35] 16-111.5(b)(3)(ii)(A); 16-111.5(b)(3)(ii)(B).

[36] *Id.* at 16-111.5(b)(3)(ii)(C); 16-111..5(b)(3)(ii)(D).

[37] *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.[38] These programs are discussed further in Section 7.4, where demand response resource choices are examined.

Clean Coal Portfolio Standard

The IPA Act contains an aspirational goal that cost-effective clean coal resources account for, 25% of the electricity used in Illinois by January 1, 2025.[39] To that end, the Plan must also include electricity generated from clean coal facilities.[40] While there is a broader definition of "clean coal facility" contained in the definition section of the IPA Act[41], Section 1-75(d) describes two special cases:the "initial clean coal facility"[42] 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").[43] 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. However, the IPA is aware of a retrofit clean coal facility that intends to begin operations within the next five years.

Retrofit Clean Coal Facilities

The IPA and the Commission are required to consider in a Procurement Plan any sourcing agreements presented by the owners of a retrofit facility to the utilities and alternate retail electric suppliers required to comply with the Clean Coal Portfolio Standard. In the case of sourcing agreements that are power purchase agreements, the contract price for electricity sales shall be established on a cost of service basis. In the case of sourcing agreements that are contracts for differences, the contract price from which the reference price is subtracted shall be established on a cost of service basis. The Agency and the Commission may approve any such utility sourcing agreements that do not exceed cost-based benchmarks developed by the procurement administrator, in consultation with the Commission staff, Agency staff and the procurement monitor, subject to Commission review and approval. Costs incurred under these provisions in the Power Agency Act or pursuant to a contract entered into under the relevant subsection of the Act shall be deemed prudently incurred and reasonable in amount and the electric utility shall be entitled to full cost recovery pursuant to the tariffs filed with the Commission.

By law, the total amount paid under sourcing agreements with clean coal facilities pursuant to the procurement plan for any given year shall be reduced by an amount necessary to limit the annual estimated average net increase in eligible retail customers' electric service bills to certain levels that are specified in the IPA Act by a set of formulas.[44] Because the IPA does not anticipate the operation of a clean coal facility until the 2017 delivery year, the maximum

[38] 220 ILCS 5-16-108.6(g)

[39] 20 ILCS 3855/1-75(d).

[40] 20 ILCS 3855/1-75(d)(1).

[41] 20 ILCS 3855/1-10

[42] *Id.*

[43] 20 ILCS 3855/1-75(d)(5)

[44] 20 ILCS 3855/1-75(d)(2).

allowable increases in rates allowed by those formulas are known today to be equal to 2.015% of the amount paid per kilowatthour by those customers during the year ending May 31, 2009.[45] For Ameren, this amounts to 0.2169 cents per kwh, and for ComEd, it amounts to 0.2382 cents per kwh[46] this Procurement Plan will not address the impact of the cost cap at this time, except in a general sense.

3.0 Load Forecasts

The forecasts of Ameren and ComEd loads for "eligible retail customers" are key inputs to the IPA's Procurement Plan. While the 2013 Procurement Plan is the fifth such plan, it is the first impacted so heavily by the advancement of retail customer choice to the residential and small commercial customer classes. Both Ameren and ComEd are required by Section 16-111.5(d)(1) of the Public Utilities Act to provide 5-year planning forecasts, which is June 2013 – May 2018 for this 2013 Procurement Plan. These forecasts provided by Ameren and ComEd are summarized below, followed by an analysis of the major drivers of load forecast uncertainty in the Illinois retail electric marketplace. This Plan examines the impacts, many of which are unique to the Illinois retail electric marketplace, of customer migration, market price implications for making the choice to receive electric supply service under the utility default rates, efficiency programs and trends, demand response opportunities and emerging technology.

3.1 <u>Ameren Illinois</u>

Ameren Illinois's forecasts and analyses for the June 2013 – May 2018 planning period are included as Appendix I to this 2013 Procurement Plan. This Appendix contains the following information:

- A document titled *"Ameren Illinois Company ("AIC") Load Forecast for the Period June 1, 2013 – May 31, 2018"* that describes the forecast methodology.
- The Ameren Energy Forecast by Customer Class assuming the incremental energy efficiency programs are implemented, as discussed later in this Plan.
- The forecast of peak and off-peak total energy and average load.
- A projection of peak and off-peak contract volumes to procure.
- Ameren's capacity projections.
- Ameren's RPS calculations with certain explicit confidential price information redacted.
- Ameren's Electric Energy Efficiency Compliance Report Submitted in accordance with 220 ILCS 5/Sec. 16-111.5B.

There is a dramatic fall-off in Ameren's load serving responsibility associated with eligible retail customers. Customer switching, both individually and as part of municipal aggregation, is a key driver, followed by general economic assumptions and impacts of energy efficiency programs. A comparison of the Ameren Illinois Base Case average load forecast submitted for this plan is summarized below, as well as a comparison to the Base Case forecast from the 2012

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[45] 20 ILCS 3855/1-75(d)(2)(E).

[46] Based on the amounts paid per kwh by those customers during the year ending May 31, 2009, as reported in the Procurement Plan filed by the IPA on September 30, 2009 in Docket 09-0373. Within that document see specifically Table Q on page 41, where the Ameren Reference Year Unit Cost for the Reference Year 2008-2009 is $107.66; and Table Y on page 55, where the analogous ComEd value is $118.23.

plan. Also shown is the March 2012 updated forecast used for the 2012 Spring procurements. This update was mandated by the Commission in its Final Order on the 2012 Procurement Plan, and provided for, in effect, a mid-course correction or informal portfolio rebalancing due to the known municipal aggregation measures on the March, 2012 ballot. This comparison is provided to illustrate the magnitude of the impacts of recent retail market developments on the load served by the IPA's procurement plans and processes.

Ameren Illinois Projected Average Demand for Eligible Retail Customers							
		Average Load (MW)					
		2013 Plan (Jul 2012 forecast)		Spring 2012 Procurement (Mar 2012 forecast)		2012 Plan (Nov 2011 forecast)	
		On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak
Year	**Month**						
2013	6	987	742	1591	1226	2018	1552
	7	1,150	923	1892	1500	2418	1916
	8	1,132	896	1914	1454	2449	1858
	9	859	724	1424	1193	1800	1511
	10	679	542	1173	994	1473	1251
	11	733	621	1262	1107	1594	1400
	12	861	760	1551	1406	1977	1797
2014	1	896	799	1620	1493	2071	1913
	2	832	747	1522	1369	1938	1746
	3	663	582	1263	1170	1604	1492
	4	567	468	1068	938	1351	1188
	5	545	451	1039	944	1321	1201
	6	777	610	1435	1198	1842	1528
	7	951	756	1800	1418	2330	1833
	8	944	743	1791	1423	2317	1840
	9	701	591	1323	1137	1693	1457
	10	546	444	1094	940	1391	1197
	11	603	517	1173	1063	1498	1361
	12	714	649	1477	1334	1903	1721
2015	1	765	693	1517	1430	1955	1845
	2	720	644	1428	1311	1832	1682
	3	571	511	1203	1108	1540	1419
	4	496	413	1024	895	1303	1137
	5	486	416	1024	923	1303	1176
	6	702	557			1808	1497
	7	878	686			2263	1807
	8	879	682			2223	1847
	9	653	542			1700	1397
	10	506	415			1376	1168
	11	561	479			1479	1309
	12	669	612			1872	1661
2016	1	718	665			1928	1839
	2	667	600			1806	1666
	3	538	491			1552	1379
	4	465	406			1295	1129
	5	469	394			1317	1138
	6	665	546			1771	1507
	7	849	681			2309	1798
	8	842	647			2218	1791
	9	621	527			1695	1378
	10	479	405			1388	1142
	11	529	464			1471	1282
	12	652	581			1863	1645

2017	1	692	633			1950	1778
	2	647	594			1804	1636
	3	514	471			1525	1366
	4	439	394			1287	1119
	5	452	370			1326	1103
	6	650	512				
	7	817	654				
	8	803	628				
	9	588	514				
	10	457	383				
	11	505	443				
	12	627	556				
2018	1	666	600				
	2	621	566				
	3	497	445				
	4	425	368				
	5	434	350				

3.2 ComEd

ComEd's forecasts and analyses for the June 2013 – May 2018 planning period are included as Appendix II to this 2013 Procurement Plan. This Appendix contains the following information:

- A document titled "Commonwealth Edison Load Forecast for Five-Year Planning Period", dated July 16, 2012, which includes ComEd's Appendices A, B, D and E. (Note that Appendix E contains information heretofore treated as confidential and which the IPA may need to release in order for the Commission to consider the IPA's proposal on whether to procure additional renewable resources in this and subsequent Procurement Plans.)
- ComEd Appendix C1: Assessment of Energy Efficiency and Load Management Potential (2011-2016) performed by the Cadmus Group, dated February 17, 2010
- ComEd Appendix -C2: Energy Efficiency Analysis Summary
- ComEd Appendix -C3: Energy Efficiency Monthly Savings Curves (by program)
- ComEd's Procurement Period Load Forecast for Total and Average Peak and Off-Peak Load.

As with the Ameren forecast, there is a dramatic fall-off in load serving responsibility associated with ComEd's eligible retail customers. Once again, individual customer switching and municipal aggregation are key drivers, followed by general economic assumptions and the impact of energy efficiency programs. A comparison of the ComEd Base Case average load forecast submitted for this plan is summarized below, as well as a comparison to the Base Case forecast from the 2012 plan. Also shown is the March 2012 updated forecast used for the 2012 Spring procurements. This update was mandated by the Commission in its Final Order on the 2012 Procurement Plan, and provided for, in effect, a mid-course correction or informal portfolio rebalancing due to the known municipal aggregation measures on the March, 2012 ballot. This comparison is provided to illustrate the magnitude of the impacts of recent retail market developments on the load served by the IPA's procurement plans and processes.

ComEd Projected Average Demand for Eligible Retail Customers							
		Average Load (MW)					
		2013 Plan (Jul 2012 forecast)		Spring 2012 Procurement (Mar 2012 forecast)		2012 Plan (Nov 2011 forecast)	
		On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak
Year	Month						
2013	6	1749	1406	2145	1751	2993	2465
	7	2042	1623	2511	2008	3651	2929
	8	1880	1499	2318	1871	3377	2740
	9	1406	1139	1730	1425	2477	2071
	10	1241	1016	1538	1282	2122	1794
	11	1364	1159	1739	1504	2338	2039
	12	1586	1372	2081	1825	2736	2407
2014	1	1594	1391	2129	1894	2733	2442
	2	1450	1277	1981	1783	2516	2272
	3	1284	1124	1733	1548	2226	2003
	4	1134	963	1495	1297	1989	1742
	5	1147	960	1458	1242	2013	1741
	6	1525	1236	1913	1568	2796	2309
	7	1827	1459	2287	1832	3447	2768
	8	1684	1359	2111	1722	3180	2603
	9	1267	1025	1589	1304	2343	1944
	10	1109	916	1399	1176	1992	1699
	11	1230	1058	1595	1398	2199	1942
	12	1461	1273	1952	1723	2621	2316
2015	1	1468	1292	1993	1789	2601	2342
	2	1341	1182	1866	1679	2408	2172
	3	1188	1043	1633	1462	2135	1922
	4	1039	893	1392	1221	1890	1672
	5	1048	891	1349	1167	1906	1675
	6	1417	1156			2704	2232
	7	1709	1369			3338	2669
	8	1575	1285			3073	2533
	9	1184	964			2251	1878
	10	1025	857			1900	1641
	11	1154	995			2125	1884
	12	1378	1200			2539	2245
2016	1	1389	1226			2517	2281
	2	1282	1129			2360	2122
	3	1133	998			2087	1880
	4	983	852			1826	1634
	5	1006	851			1875	1638
	6	1371	1103			2682	2177
	7	1650	1340			3289	2675
	8	1541	1231			3079	2466
	9	1135	942			2193	1870
	10	992	831			1858	1617
	11	1127	974			2101	1865
	12	1345	1176			2496	2225
2017	1	1360	1205			2491	2263
	2	1241	1102			2306	2095
	3	1102	978			2050	1864
	4	955	828			1788	1607
	5	985	830			1860	1616
	6	1346	1076			NA	NA
	7	1617	1315			NA	NA
	8	1504	1210			NA	NA

	9	1103	919			NA	NA
	10	970	810			NA	NA
	11	1102	947			NA	NA
	12	1309	1150			NA	N A
2018	1	1331	1181			NA	NA
	2	1208	1079			NA	NA
	3	1071	952			NA	NA
	4	934	806			NA	NA
	5	961	807			NA	NA

3.3 Load Forecast Uncertainty

Each of the utilities' load forecast analyses attached hereto as Appendices describe the drivers of uncertainty analyzed by ComEd and Ameren Illinois, respectively. The discussion below is a general overview from the IPA's perspective. The following key drivers of load forecast uncertainty are briefly defined and examined:

- Customer Migration
    - Individual Switching
    - Municipal Aggregation
    - Hourly Pricing
    - Market Price as It Affects the Choice Between ARES and Utility Supply
- Efficiency
    - Building Codes
    - Energy Efficiency Resource Standards
- Demand Response
- Emerging Technology

3.3.1 Customer Migration

The Procurement Plan includes the risk, in deciding how much electricity supply to purchase and at what price, that forecasts may be over- or under-estimating the likelihood that customers will leave utility fixed-price supply for competitive choices. Conversely, forecasts must consider the likelihood of customers who have migrated away from utility fixed-price supply returning in the future to such service. This risk comes from at least three sources: (1) Individual Customer Choice; (2) Municipal Aggregation; and (3) Hourly Pricing.

When restructured markets were phased-in in Illinois beginning in 1997, customer switching to ARES service was slow to take off in the residential and small commercial customer classes due, in part, to "transition charges" which the utilities applied to ARES service customers' bills, as well as the existence of frozen bundled service rates. By January 2007, those factors no longer existed but switching to ARES service remained slow due, in part, to the relatively high costs of customer acquisition and service for these smallest of utility customers. It was not until ComEd and Ameren began offering consolidated billing and purchase of receivables to ARES that residential and small commercial switching accelerated. ComEd and Ameren's tariffs implementing Utility Consolidated Billing ("UCB") and Purchase of Receivables ("POR") became effective in August of 2011 and August of 2009, respectively.[47] As an example of their positive marketplace impact, following the Commission's approval of ComEd's and Ameren's tariffs, the number of residential customers taking ARES service in ComEd territory increased from essentially zero in March 2011 to over 70,000 in June 2011.[48] From June 1, 2011 to August 12, 2011, residential enrollment with

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[47] *See generally* ICC Docket No. 10-0138, Final Order dated Aug. 17, 2011; ICC Docket No. 08-0619, -0620, -0621 (cons.), Final Order dated Aug. 19, 2009).

[48] ICC Docket No. 11-0660, Final Order dated Dec. 21, 2011, at 56.

ARES in ComEd's service territory averaged 1,150 customers per day.[49] If that trend were to continue, ComEd projected last year that over a million residential customers could switch to ARES service by 2013-2014.[50]

For Ameren Illinois, residential switching began in earnest in July 2011, with the rate of switching steadily increasing ever since. Considering the recent success of municipal aggregation, Ameren Illinois now has in excess of 315,000 residential accounts that have switched to ARES with this quantity expected to increase further.

The Commission's Office of Retail Market Development reports the following increase in the numbers of residential suppliers over the last 12 months. [51]

Residential Suppliers		
	May 2011	May 2012
ComEd – ICC certified	22	40
ComEd - active	8	27
Ameren IL – ICC	16	26
Ameren IL - active	3	10

Whether as a result of municipal aggregation (discussed in further detail below) or as a result of individual consumer choice, migration of eligible retail customers indicates a greater penetration of ARES marketing efforts, a lowering of barriers to competition, and the natural market forces responding to market conditions in Illinois.

Municipal Aggregation

The impacts of municipal aggregation in Illinois have the potential to far outweigh any impacts associated with individual customer supply choice decisions, because of the potential to move large numbers of customers to or away from an individual supplier with a single decision. Public Act 96-0176 amended the IPA Act to allow municipal corporate authorities or county boards to adopt ordinances aggregating residential and small commercial retail electrical loads within their jurisdiction to enter into an electricity purchase agreement with a retail electric supplier.[52]

The Illinois Commerce Commission Office of Retail Market Development, in its June 2012 Annual report referenced above, has reported the dramatic increase in municipal aggregation activity in Illinois from 2011 to 2012. Buoyed by the savings success experienced by the programs instituted by ballot in 2011, and the continued downward trend in market-based electricity supply prices in Illinois, 306 communities placed an opt-out aggregation referendum on the March 20, 2012 ballot, with 245 of those referenda passing. Further illuminating statistics are tabulated below.[53]

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[49] ICC Docket No. 11-0660, Final Order dated Dec. 21, 2011, at 56.

[50] ICC Docket No. 11-0660, Final Order dated Dec. 21, 2011, at 56.

[51] Office of Retail Market Development, Illinois Commerce Commission, 2012 Annual Report, June 2012

[52] Public Act 96-0176 (Aug. 2009).

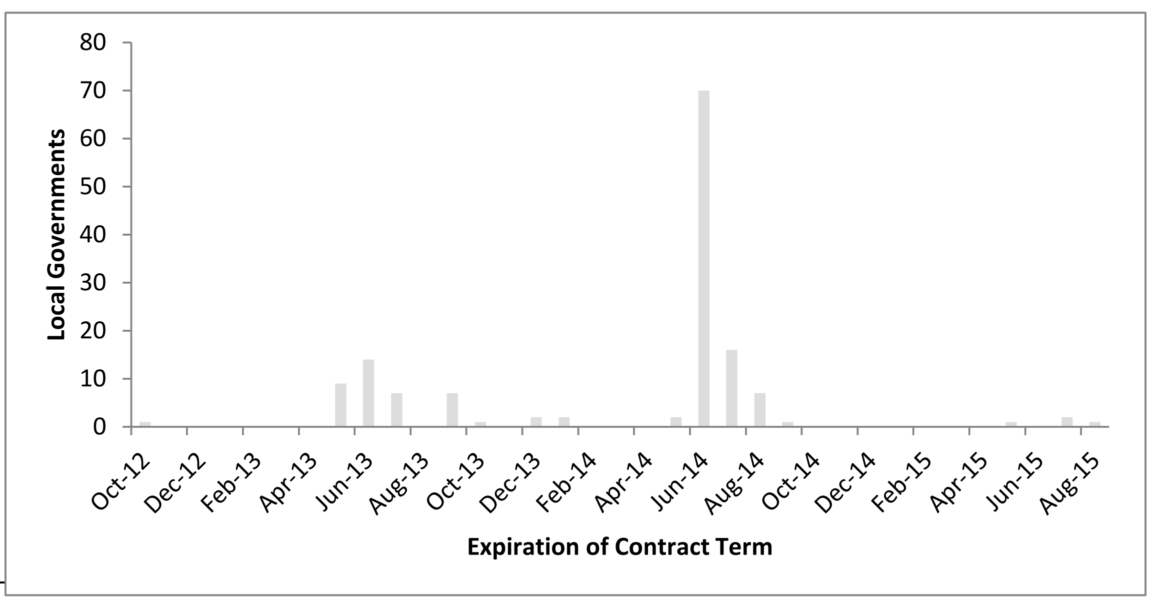
[53] Office of Retail Market Development, Illinois Commerce Commission, 2012 Annual Report, June 2012

Municipal Aggregation Statistics as of June 29, 2012		
	April 2011	March 2012
Referenda Passed	20	245
Aggregation Programs Announced or Implemented	19	200
# of "Winning" Suppliers - ComEd	4	7
# of "Winning" Suppliers – Ameren Illinois	N/A	7
Average Rate - ComEd	5.81	4.87
Average Rate – Ameren Illinois	N/A	4.10

Considering that the current typical average annual "price to beat" for ComEd is 7.77 cents/kWh and that Ameren Illinois' seasonal prices range from roughly 5.5 to 6.2 cents/kWh,[54] it is not surprising that municipal/county aggregation has become such an attractive alternative, with an opportunity to also dramatically reduce the load forecasts for Ameren and ComEd.

The chart below, however, shows that the above prices obtained through municipal aggregation are set for only a relatively short period of time. A majority of the known contracts expire during the Summer of 2014. As discussed below, the relative levels of market prices and the utilities' blended portfolio costs at the time these municipal aggregation prices expire will determine, in large part, the sustainability of the shift away from utility fixed-price supply service for the 2014-2015 delivery year and beyond.

Distribution of Municipal Aggregation Contract Terms



[54] http://www.pluginillinois.org/

The IPA concurs with the utilities' analyses that conclude there will likely still be some headroom between utility and ARES price offers in the 2014/2015 delivery year, and the IPA anticipates and expects that the policies supporting competitive electricity markets will continue. Eligible retail consumers currently served through the IPA portfolio will continue to migrate towards ARES options.[55] The IPA understands that the City of Chicago intends to place the opt-out aggregation question on the November 2012 ballot, as well as at least one county. An affirmative vote in Chicago could result in a massive migration away (estimated at roughly 9,000,000 mWh/year) from ComEd fixed-price service well before the beginning of June 2013-May 2014 delivery year, the first year of this Procurement Plan. The probability of this occurring is judged to be high based on the success of other aggregation programs, and this shift of Chicago load is included in the ComEd Base Case forecast. . For Ameren Illinois, at least eighty additional municipalities and counties will pursue November 2012, with the potential for another series of referenda in 2013. Under the expected forecast scenario submitted by Ameren Illinois, the outlook is that a majority of residential load could be switched by June 2013, and under the low forecast scenario (which includes high switching assumptions) a significant majority could be switched by June 2013.

Anticipating the possibility of load volatility due to shifts in customer load to ARES, Section 16-115.5(b)(4) of the PUA requires that the IPA determine criteria for rebalancing its portfolio in the event of significant shifts in load.

In the 2012 Procurement Plan, the IPA proposed that Ameren and ComEd should "true-up" their forecasted amount of customer switching expected due to municipal aggregation programs.[56] To do this, the IPA proposed that Ameren and ComEd survey the actual number and size of the municipalities that file with the relevant election authority to hold, or who have already passed referenda approving "opt out" aggregation.[57] Based on the results from these surveys, the IPA proposed that Ameren, ComEd, Staff of the ICC, and the Procurement Administrator and Monitor would rebalance the portfolio commensurate with the change in forecasted customer switching due to municipal aggregation programs.[58] In fact, the Commission provided an opportunity to rebalance the portfolio when it ordered that both utilities submit to the IPA updated forecasts prior to the Spring 2012 procurement. These forecasts, submitted to the IPA in March 2012, incorporated the knowledge that a significant number of referenda were going to be held that month. The regular Spring 2012 procurement events provided an opportunity to re-examine the gap between anticipated supply and demand and adjust purchases accordingly, mitigating the need for an explicit and separate supply rebalancing. The difference between the 2012 and 2013 Procurement Plan forecasts illustrates the power of competitive choices in a marketplace that facilitates an ease of making those choices.

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[55] ICC Docket No. 11-0660, Final Order dated December 21, 2011 at 5.

[56] *Id.* at 37.

[57] *Id.* at 37.

[58] *Id.* at 37.

Mitigating further the need for significant portfolio rebalancing going forward is the fact that sizeable contracts for energy and capacity products of 2007 vintage that are currently included in ComEd and Ameren's current supply mix and "price to compare" expire by May of 2013. Ameren's 1000 MW contract ends at the end of 2012, while ComEd's 3000 MW contract ends at the end of May 2013. For ComEd, in particular, this provides an opportunity to better accommodate a migration of City of Chicago customers out of the IPA portfolio; the IPA anticipates that Chicago and other potential November ballot municipal aggregation-related migration should be well settled before a Spring 2013 procurement is conducted.

Expiration of these relatively high priced portions of the supply portfolio should result in a reduction in the utility default service price, at which point some customers may find that the default supply option may be more economical than their current ARES offerings. Given the 20-year bundled REC and energy contracts entered into by Ameren Illinois and ComEd in late 2010, and the recovery of prior and current balancing costs (through the day-ahead market and captured through the PEA), it is likely that the utility default prices will still be above current ARES offers. This is especially true as those long-term contracts become a relatively larger part of the utility supply portfolio as the load denominator goes down due to customer migration.[59] See also the discussion below on market-price impacts on customer migration.

The amount of customer load forecasted to switch from the IPA portfolio to ARES-served load also affects the purchase of renewable resources and will be further discussed in that section of this Procurement Plan.

Hourly Pricing

Because customers who take electric supply pursuant to an hourly pricing tariff are not "eligible retail customers" under the PUA, the IPA is not obligated to purchase electrical supply on those customers' behalf.[60] Therefore, the amount and corresponding electrical load of customers who take service pursuant to an hourly pricing tariff affects the IPA's required procurement portfolio for the next five years. Based on historic trends, it is unlikely that the number or load of customers served by hourly pricing tariffs will significantly impact the IPA's procurement plan. However, recent developments in the Commission proceedings implementing Smart Grid infrastructure indicate that new tariff structures, in addition to the statutorily required Peak-Time Rebate, may be implemented by ComEd within the next calendar year or over the course of the planning horizon. The effect of these new tariffs on the obligations of the IPA is yet to be determined.

Market Price

Market price is discussed here because it may impact the level of customer migration. Section 6.1 more generally discusses market conditions, including market price, as they may affect the utility supply costs.

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[59] This disparity is mitigated somewhat to the extent that the Alternative Compliance Payment ("ACP") charged to ARES is based increasingly on the REC price from the long-term renewable contracts as the 20-year contracts take up a greater percentage of the renewable resource purchase.

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

Well-informed customers and their suppliers will make rational economic decisions based on the relative costs of their electricity supply alternatives. This was vividly illustrated in the early years of the competitive transition in Illinois. The Electric Service Customer Choice and Rate Relief Law of 1997, which established Article XVI of the Public Utilities Act,[61] created a temporary retail supply option available to commercial and industrial customers known as the Power Purchase Option ("PPO"). This offer was based on an administratively-determined market price, which at times was lower than market-based supply offers of ARES. At other times, it was higher. Not only did customers choose the PPO option when it was lower-priced than ARES offers, but ARES themselves placed their customers on the PPO when it was economically advantageous to do so. In other words, ARES made the rational choice to use the PPO as their supply source in lieu of higher-priced market based resources. This raises the related question in the context of this Procurement Plan: could utility default service be used as an ARES supply option as was the PPO, increasing load volatility for the utility portfolio?

With an eye towards price stability and hedging short- and intermediate-term market price risk, the current IPA-arranged utility supply portfolio is based on a ladder of products which, over the long run, will tend to dampen utility price increases in a rising wholesale market and also dampen utility price decreases when wholesale market prices are falling. While protecting consumers against price volatility, as market prices have fallen in the last several years utility tariffed supply rates have not fallen as quickly, resulting in the current significant headroom between utility and ARES supply prices. Hence, the huge savings available through municipal aggregation – which an ARES can serve at current market prices without the burden of legacy contracts. This has significantly reduced utility load serving obligations. With market prices for electric energy projected to increase in the future, the potential exists for the utility portfolio to be priced lower than market if the current portfolio construct is maintained.[62] If ARES and customers once again return to utility supply in this situation, will Illinois experience the kind of mass customer swings experienced under the PPO?

The evidence suggests that this is less likely than earlier in Illinois' transition to competitive markets and care should be taken to not cause the utility to over-hedge today for this eventuality. If utilities are unhedged for this returning load and meet this returning load obligation through short term or day-ahead purchases, risk is mitigated somewhat because those purchases will be made at the same supply prices being faced by ARES. Furthermore, even though ARES maintained a relationship with the retail customers they placed on the PPO, it is not so easy (or necessarily possible) to do so under today's utility tariffs, where customers that return to utility bundled service are subject to a stay of 12 months if they do not choose another supplier within a 2-month window. An ARES is not likely to want to sever its customer relationships, as would occur if a customer is required to stay on utility supply for a full year. The loss of a customer relationship for a relatively long period of time is a significant factor risk factor for ARES that might be otherwise inclined to use utility service as a short-term supply option, and that differentiates current conditions from those of the PPO era.

At this juncture, the IPA recommends continued watchful analysis of retail and wholesale markets as they impact Illinois retail customer migration and retail default service costs. As noted above, the bundled utility rate is most likely to beat ARES offers in a situation of extended wholesale market price increases, which the IPA will monitor, along with the Commission and other interested stakeholders. However, it cannot recommend the purchase of supply to cover the risk of returning customers, especially in a spring 2013 procurement event, well before the majority of

[61] 220 ILCS 5/16

[62] As noted above, factors including load risk and long-term contracts may mitigate or overpower this effect.

municipal aggregation supplier agreements are scheduled to terminate. With respect to the possibility that the City of Chicago may not actually migrate to an ARES by June 2013, the IPA notes that ComEd is projected to be long on supply for the 2013/2014 delivery, so is already well-hedged for this possibility without making any new purchases.

3.3.2 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.[63] 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.

Building Codes

As noted by the utilities in their load forecast documentation, increasing energy efficiency of building stock and appliances is serving to dampen overall electric load growth and, in the face of customer switching, utility load serving obligations. A major driver of efficiency improvement is enhanced building codes and energy efficiency resource standards. These are described and examined below.

Energy Efficiency Building Act

Public Act 096-0778, which was signed into law on August 28, 2009, created a new statewide energy conservation code for residential and commercial buildings by amending the Energy Efficient Commercial Building Act,[64] renamed the Energy Efficient Building Act. The new requirements for residential buildings became effective on January 29, 2010. The efficiency gains of the 2009 code set a new baseline for International Energy Conservation Code-compliant homes and buildings, and while, there will be regional variability and uncertainty in the technology penetration, preliminary estimates from U.S. DOE suggest the 2009 IECC will be at least 18 percent and possibly even 22 percent more energy efficient than the 2006 IECC.

Chicago Energy Conservation Code

In November, 2008, the Chicago City Council passed an amendment to Chapter 18-13 putting into place the Chicago Energy Conservation Code for residential and commercial properties. The code includes requirements for residential properties to improve energy efficiency through the insulation of floors, roofs and walls as well as the installation of energy efficient windows and mechanical systems. Commercial buildings must meet the ASHRAE/IESNA 90.1-2004, Energy Standard for Buildings except Low-Rise Residential Buildings, Section 4.1 Compliance Requirements.

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

[64] "Illinois Energy Conservation Code for Commercial and Residential Buildings." http://www.ildceo.net/dceo/Bureaus/Energy_Recycling/IECC.htm.

Building Industry Training and Education

Through the EEPS Illinois Energy Now program, DCEO has provided grants to various organizations providing training and education to trade allies and contractors performing work related to energy efficiency, building codes, and market transformation.[65]

Energy Efficiency Resource Standards

The American Council for an Energy Efficient Economy (ACEEE) reports the widespread adoption of "energy efficiency resource standards" ("EERS") and long-term energy savings targets. The most recent scorecard published by ACEEE in 2011 noted that 24 states have energy EERS (25 by the time the report was published). The widespread adoption of energy efficiency resource standards has put forth targets that, if met, will greatly reduce consumption and overall demand growth. However, this growth has put pressure on utility programs to increase customer participation, either in existing programs or through the development of new programs, including those reaching markets previously under-served or not served at all, and by implementing a more comprehensive set of measures than programs achieved earlier.

Appliance Standards and Energy Efficiency Savings

A joint report of the American Council for an Energy Efficient Economy ("ACEEE") and the Appliance Standards Awareness Project ("ASAP") examined the impact of appliance, equipment and lighting standards on electricity consumption.[66] Such standards, a cornerstone of U.S. energy policy since the 1980s, have significantly reduced U.S. energy consumption, providing large benefits for consumers and businesses. Taking into account products sold from the inception of each national standard through 2035, existing standards are estimated to net consumers and businesses more than $1.1 trillion in savings cumulatively.[67] By 2035, cumulative energy savings will reach more than 200 quads, an amount equal to about two years of total U.S. energy consumption.

Standards have had a particularly large effect on electricity use. On an annual basis, products meeting existing standards reduced U.S. electricity use in 2010 by about 280 terawatt-hours (TWh), a 7% reduction.[68] The electricity savings will grow to about 680 TWh in 2035, reducing U.S. electricity consumption by about 14% in each of those years.

For individual consumers, benefits have been very large, and are expected to grow as new and revised standards take effect. Based on a combination of existing and new standards, a typical household replacing its major appliances every 15 years could save over 180 MWh of electricity. Absent standards, this typical household's electricity use over this period would have been about 35% higher.

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[65] Illinois Energy Now DCEO 2011-2012 Report. June 26, 2012 at 18.

[66] "The Efficiency Boom: Cashing In on the Savings from Appliance Standards," ACEEE/ASAP (March 2012), Amanda Lowenberger, Joanna Mauer, Andrew deLaski, Marianne DiMascio, Jennifer Amann, and Steven Nadel (Report Number ASAP-8/ACEEE-A123).

[67] *Id.* at iii.

[68] *Id.*

3.3.3 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 of this Procurement Plan contains the IPA's discussion and recommendations for specific demand response resources to be included and approved in the 2013 Procurement Plan.

3.3.4 Emerging Technology and Load Forecast Uncertainty

A wide range of emerging supply side, demand side, and intermediating technologies will affect future load forecasts. These technologies are being developed and deployed at different rates and will affect load forecasting in different timeframes. Most of them depend on a common enabling infrastructure known as a "Smart Grid": a digital information network connecting all nodes of supply and demand and providing real time information to utilities, end-users, and authorized third parties. The smart grid, and in particular, the types of investments identified in the new Energy Infrastructure Modernization Act ("EIMA")[69], hold great potential benefits for Illinois electric customers, including:

- Improvements in operational efficiency and system reliability, including reduced metering costs through automated metering and improved asset life through improved information on maintenance issues in wires or in substations, before equipment failures or outages occur.
- Consumer benefits through improved usage information and ability to manage energy usage through energy efficiency, demand response and distributed generation investments, not only through expanded rate options that will give additional potential money saving opportunities from energy conservation and load shifting but through new technologies made practicable by smart grid investments.
- Environmental benefits through smarter long-term generation and transmission investments and more efficient resource utilization, avoided GHG emissions associated with peak energy usage and meter reading, and improved distributed and renewable resource interconnection.

If a utility chooses to have its delivery services rates set under the EIMA, that utility is obligated to make investments in transmission and distribution infrastructure improvements. Both ComEd and Ameren have elected to do so, and in turn are now obligated to invest $1,300,000,000 and $360,000,000, respectively in "Smart Grid electric system upgrades."[70]

Under the Energy Infrastructure and Modernization Act of 2011, full deployment of the Smart Grid may take a decade or more. But as sections of the grid are modernized and central office systems and software are modified to accommodate the new information flow, customers will be able to take advantage of new technologies in areas where Advanced Metering Infrastructure (AMI) is operational. Alternative suppliers of energy products can be expected to develop and market new products and services to residential and small commercial customers as deployment advances and utility tariffs may be set to accommodate AMI-enabled services and pricing options.

With only the 130,000 AMI meters installed in ComEd's 2010 pilot program presently in place and with most applications not yet functional, load forecasts for the 2013 Procurement Plan will not be affected, but the combined effect of emerging technologies will grow as AMI is deployed

[69] Public Act 97-0616, as modified by Public Act 97-0646.

[70] 220 ILCS 5/16-108.5(b)(1)(B).

statewide. New demand-side technologies primarily are designed to shift load from peak periods to off-peak periods. Future energy management may be facilitated through the introduction of automatic controls and mobile smart phone applications. Although some emerging technologies will improve energy efficiency, others are part of an ongoing electrification trend that may increase overall kilowatt-hour usage by replacing fossil energy sources such as petroleum and natural gas.

Emerging technologies include the following:

- **Electric Vehicles (EV)** – A 2% penetration rate for electric vehicles in the ComEd and Ameren service territories represents more than 100,000 vehicles. Assuming electricity usage of 25kwh/100 mile, an EV would use about 3 MWh to drive 12,000 miles per year, and 100,000 vehicles would add 300,000 MWh to statewide annual energy needs. Forecasts for penetration rates of electric vehicles are widely variant and tied to anticipated comparative costs to own and operate fossil fueled vehicles. However, these vehicles could be expected to charge largely at night, and electric vehicles owners would likely opt for time-variant electric rates to take advantage of lower off-peak power prices.
  - Charging Station Regulation - House Bill 5071, passed in the spring of 2012, would amend the PUA to provide that "an entity that furnishes the service of charging electric vehicles does not and shall not be deemed to sell electricity and is not and shall not be deemed a public utility" or an "alternative retail electric supplier" unless the entity is otherwise deemed a utility or alternate supplier, or is otherwise subject to regulation under this Act.[71] This amendment may provide regulatory certainty to entities seeking to furnish electricity for the charging of PEVs who were uncertain about their designation under the PUA, thus potentially eliminating a barrier to market entry. The legislation also requires the ICC to initiate a rulemaking to establish certification requirements for individuals or entities that install, maintain, or repair electric vehicle charging stations. This statutory directive may impact ICC Docket 12-0212, an existing rulemaking to establish certification requirements for charging stations. The Commission opened this proceeding in response to a legislative directive in Public Act 97-0616, which added Sec. 16-128A to the PUA. The extent to which future regulations related to charging station installations require installers or customers to notify the utility of the installation will impact the accuracy of future utility load forecasts.
  - Ameren forecasts a PEV adoption rate of between 156,215 to 236,690 PEVs by 2020.[72]
  - ComEd forecasts between a few thousand to 20,000 PEVs in the utility's service territory by the end of 2013.[73] Using national forecasts, ComEd projects that the total cumulative number of PEVs on the road in the utility's service territory by 2020 could vary between 32,000 and 300,000.[74]
  - The Commission initiated a stakeholder process that led to the formation of five stakeholder-led workshops in the fall of 2011. These workshops culminated in the development of the ICC PEV Initiative Report and Recommendations. Of relevance to the IPA, stakeholders agreed that the existing RRTP programs provide "the correct price signals to PEV owners for their vehicle charging needs" and are

[71] 220 ILCS 5/3-105(c)and 220 ILCS 5/16-102.
[72] Ameren Illinois Initial Assessment of Plug-in Electric Vehicles at 9.
[73] Commonwealth Edison Company Initial Assessment of the Impact of the Introduction of Plug-in Electric Vehicles on the Distribution System at 6.
[74] Commonwealth Edison Company Initial Assessment of the Impact of the Introduction of Plug-in Electric Vehicles on the Distribution System at 17.

sufficient to meet the charging needs of PEV owners.[75] While no ARES currently offer a dynamic pricing option, the rates workshop found evidence from other states that ARES "will offer time-variant rates as smart meters become available."[76] The extent to which PEV owners switch out of the portfolio to participate in RRTP programs or take service from an ARES affects the size of the IPA's portfolio as well as the load shape of the customers served.

- **Electric Thermal Storage (ETS) Heating** -- Using a radiator filled with bricks as a heat sink, ETS heating effectively stores heat derived from off-peak electricity, needing only a small fan to radiate the heat during peak periods. Controllers anticipate the amount of stored heat to be needed based on outside temperature and individual settings. ETS can be expected to be installed primarily in new construction. Because more than 90% of residential heating in Illinois is fueled by natural gas, ETS heat would add to off-peak electricity loads.
- **Electric Thermal Storage Cooling** – Similar to ETS heating, ETS cooling uses off-peak electricity to make ice or a chilled chemical mixture, thus avoiding high cost peak power usage for compressors. Long available for larger cooling loads, this technology is under development for residential scale applications and can be expected to be commercialized as time variant electricity rates make it cost-effective.
- **Smart Appliances** – Connected through a Home Area Network (HAN), smart appliances "know" when to run and when not to run based on programmed instructions about price responsiveness, desired comfort levels and other settings. Projections based on experimental installations show significant load shifting opportunities.
- **Advanced Electricity Storage** – Cost-effective storage technology has the potential to reshape electricity load, thus improving capacity utilization of generation, transmission and distribution, and reducing overall energy costs due to lower peak electricity prices. Emerging electricity storage technologies include flow batteries, high temperature batteries, lithium ion batteries, flywheels, and compressed air storage. The modular nature of many of these technologies allows a variety of deployment options: by customers, by utilities at electricity substations, and by generators at wind farms. The relatively high costs of these technologies do not make for a compelling economic case in most applications at today's electricity market prices, however, intensive global R&D is producing rapid advancements that may soon lead to broader commercialization.
- **Central Direct Load Control** -- Programs such as those now offered by utilities to cycle air-conditioning usage during peak periods may be facilitated through AMI applications, offered by third party providers, and could be expanded to include other types of loads. The effect of greater direct load control would be reduced peak usage.
- **Distributed Generation** -- Emerging technologies may allow a much larger segment of customers to self-generate cost-effectively. Advancements in fuel cells and microturbines fueled by natural gas, as well as small-scale cogeneration of heat and power, are reducing costs to the point that these technologies may eventually become competitive with central station generation. PV solar costs also have plummeted in recent years. The pairing of distributed generation with net metering tariffs and/or new small-scale storage options may create a cost-effective option for a significant portion of small-volume electricity loads.

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[75] ICC Initiative on Plug-In Electric Vehicles Executive Summary Report and Recommendations Page iii.

[76] ICC Initiative on Plug-In Electric Vehicles Executive Summary Report and Recommendations Page iii.

To spur development of this technology option, PA 97-0616 added a distributed generation component to the renewable portfolio requirements for utilities and ARES. See Section 8.4 of this Plan.

While all of these emerging technologies may at some point be subject to rapid and even simultaneous growth, they are unlikely to achieve market penetration so quickly as to provide short-term load forecasting uncertainty, such as in a single IPA procurement plan. However, the combined effect of emerging technologies could become a significant over time.

3.4 Recommended Planning Forecast Scenario

After consideration of all the risk and uncertainty factors discussed above, the IPA recommends the use of the Expected Load Forecasts provided by each of the utilities. These forecasts do not include the impacts of new or incremental efficiency programs identified by the utilities for IPA consideration. The IPA addresses these incremental programs in Section 7.0 of this Procurement Plan: Resource Choices for the 2013 Procurement Plan.

4.0 Existing Resource Portfolio and Supply Gap to Be Filled

The IPA has historically purchased supply in standard 50-MW peak/off-peak/around the clock blocks. Prior procurements have included a supply strategy designed to minimize price risk by procuring a "ladder" of standard energy products so that 100% of the first year in a 3-year procurement plan is fully hedged (meaning that existing contracts cover 100% of forecast load), 70% of the second year is hedged, and 35% of the third year is hedged. Because energy markets are only liquid and visible for a three-year horizon, the IPA has determined that, as a general matter, hedging for any part of the fourth and fifth years of the utility forecast period would introduce excessive and unnecessary price risk. The exception has been several longer term procurements mandated by the legislature, including a 20-year bundled REC and energy purchase, starting in June 2012, made by Ameren and ComEd in December 2010, and the February 2012 "Rate Stability" procurements mandated by Public Act 97-0616 for block energy products covering the period June 2013 through December 2017. The discussion below explores in more detail the supply gap between the updated utility load projections described in more detail in Section 3.0 and the supply already under contract for the planning horizon. The IPA proposes to address the gaps (if any) in supply as described in Section 6.0 - Managing Supply Risks and Section 7.0 - Resource Choices for the 2013 Procurement Plan.

4.1 Ameren

The following illustrates the current gap in the Ameren supply portfolio for the June 2013-May 2018 planning period, using the Expected Load Forecast described in Section 3. Quantities shown are average peak and off-peak MW for both loads and historic purchases. Statistics are shown for the full 5-year forecast horizon, even though the IPA's procurement plans have generally only prescribed purchases for a three-year forward horizon. This is being done so that when, later in this Plan we examine resource choices, we have a longer term scenario of expected load requirements. Nor do the tables below for both Ameren Illinois and ComEd represent the recommended amounts to be purchased in any future year. They are simply illustrative of the supply gap. How to fill that gap is the subject of Sections 6.0 and 7.0 of this Plan.

Ameren Illinois Expected Load and Current Hedge Position												
	Avg. Peak Contract Volumes						Avg. Off-Peak Contract Volumes					
Contract Month	Expected Load MW	2011 MW	2012 MW	20-YR MW	SB 1652 MW	Residual MW	Expected Load MW	2011 MW	2012 MW	20-YR MW	SB 1652 MW	Residual MW
Jun-13	987	750	0	47	650	(460)	742	550	0	48	650	(506)
Jul–13	1,150	850	0	28	650	(378)	923	700	0	40	650	(467)
Aug-13	1,132	900	0	30	650	(448)	896	700	0	50	650	(504)
Sep-13	859	650	0	44	650	(485)	724	600	0	48	650	(574)
Oct-13	679	550	0	71	650	(592)	542	500	0	86	650	(694)
Nov-13	733	550	0	89	650	(556)	621	500	0	93	650	(622)
Dec-13	861	700	0	74	650	(563)	760	650	0	69	650	(609)
Jan-14	896	750	0	78	650	(582)	799	700	0	86	650	(637)
Feb-14	832	700	0	72	650	(590)	747	650	0	79	650	(632)
Mar-14	663	600	0	83	650	(670)	582	550	0	92	650	(710)
Apr-14	567	500	0	90	650	(673)	468	450	0	98	650	(730)
May-14	545	550	0	70	650	(725)	451	450	0	77	650	(726)
Jun-14	777	0	0	45	650	82	610	0	0	50	650	(90)
Jul-14	951	0	0	28	650	273	756	0	0	40	650	66
Aug-14	944	0	0	32	650	262	743	0	0	48	650	45
Sep-14	701	0	0	42	650	9	591	0	0	50	650	(109)
Oct-14	546	0	0	71	650	(175)	444	0	0	86	650	(292)
Nov-14	603	0	0	93	650	(140)	517	0	0	89	650	(222)
Dec-14	714	0	0	70	650	(6)	649	0	0	72	650	(73)
Jan-15	765	0	0	82	650	33	693	0	0	82	650	(39)
Feb-15	720	0	0	72	650	(2)	644	0	0	79	650	(85)
Mar-15	571	0	0	79	650	(158)	511	0	0	96	650	(235)
Apr-15	496	0	0	90	650	(244)	413	0	0	98	650	(335)
May-15	486	0	0	73	650	(237)	416	0	0	74	650	(308)
Jun-15	702	0	0	43	200	459	557	0	0	53	200	304
Jul-15	878	0	0	27	200	651	686	0	0	41	200	445
Aug-15	879	0	0	32	200	647	682	0	0	48	200	434
Sep-15	653	0	0	42	200	411	542	0	0	50	200	292
Oct-15	506	0	0	74	200	232	415	0	0	82	200	133
Nov-15	561	0	0	89	200	272	479	0	0	93	200	186
Dec-15	669	0	0	70	200	399	612	0	0	72	200	340
Jan-16	718	0	0	86	200	432	665	0	0	79	200	386
Feb-16	667	0	0	69	200	398	600	0	0	78	200	322
Mar-16	538	0	0	76	200	262	491	0	0	100	200	191
Apr-16	465	0	0	94	200	171	406	0	0	94	200	112
May-16	469	0	0	70	200	199	394	0	0	77	200	117
Jun-16	665	0	0	43	0	622	546	0	0	53	0	493
Jul-16	849	0	0	31	0	818	681	0	0	37	0	644
Aug-16	842	0	0	29	0	813	647	0	0	52	0	595
Sep-16	621	0	0	42	0	579	527	0	0	50	0	477
Oct-16	479	0	0	78	0	401	405	0	0	79	0	326
Nov-16	529	0	0	85	0	444	464	0	0	97	0	367
Dec-16	652	0	0	74	0	578	581	0	0	69	0	512
Jan-17	692	0	0	82	0	610	633	0	0	82	0	551
Feb-17	647	0	0	72	0	575	594	0	0	79	0	515
Mar-17	514	0	0	76	0	438	471	0	0	100	0	371
Apr-17	439	0	0	99	0	340	394	0	0	90	0	304
May-17	452	0	0	66	0	386	370	0	0	80	0	290

Jun-17	650	0	0	43	0	607	512	0	0	53	0	459
Jul-17	817	0	0	31	0	786	654	0	0	37	0	617
Aug-17	803	0	0	29	0	774	628	0	0	52	0	576
Sep-17	588	0	0	44	0	544	514	0	0	48	0	466
Oct-17	457	0	0	74	0	383	383	0	0	82	0	301
Nov-17	505	0	0	85	0	420	443	0	0	97	0	346
Dec-17	627	0	0	77	0	550	556	0	0	67	0	489
Jan-18	666	0	0	82	0	584	600	0	0	82	0	518
Feb-18	621	0	0	72	0	549	566	0	0	79	0	487
Mar-18	497	0	0	76	0	421	445	0	0	100	0	345
Apr-18	425	0	0	99	0	326	368	0	0	90	0	278
May-18	434	0	0	66	0	368	350	0	0	80	0	270

The comparison of hedged supply and projected load shows that no purchases of energy are required for the 2013/2014 delivery year. In fact, depending on the month, supply is 400-700 MW over-hedged under this scenario, with the average being 550 MW during the peak period and 600 MW in the off-peak period.[77] For the 2014/2015 delivery year, Ameren is again generally over-hedged, with the exception of July and August. It is not until the 2015/2016 delivery year that Ameren Illinois is consistently short, driven largely by the fact that it was unable to purchase sufficient cost-effective[78] supply during the procurement mandated by Public Act 97-6016, falling 400 MW short. If a procurement event were to be held in the spring of 2013 to fill a 2015/2016 delivery year portfolio shortfall, there is a greater likelihood that any shortfall would be cost-effectively filled. Note that ComEd was able to purchase supply for the 2015/2016 supply year and through December 2017 because the legislature effectively prescribed they purchase a supply strip with a term of June 2013-Dec 2017 in order to effect a specified price construct applicable only to ComEd. Ameren products were specified as single delivery year products in order to increase the opportunities for lower bids in each individual year.

Regarding the excess hedged supply, the IPA considered two options: 1) allowing the energy to settle in the MISO markets or 2) a reverse RFP to sell excess through the bilateral market. The IPA recommends that the energy settle through the MISO markets since the benefits appear to outweigh the drawbacks as illustrated below. A similar set of drawbacks and benefits applies to ComEd's excess hedged supply. The IPA therefore recommends that no reverse RFP be undertaken for either utility in this Procurement Plan.

Benefits:

a) The 2013/14 energy hedges are moderately "out of the money" and selling may result in locking in a loss.
b) Buyers in any reverse RFP may seek purchases below market price.
c) The cost of administering a reverse RFP would be avoided.
d) A reverse RFP in spring would do nothing to mitigate price exposure between now and the RFP event.

[77] These values are rounded to the nearest 50MW, to reflect that the standard product currently purchased by the IPA is a 50 MW block.
[78] Where cost-effective means bids received are lower than the confidential price benchmarks approved by the Commission for the products being bid.

e) Any increase in energy prices during 2013/14 could prove beneficial through the MISO settlement process, whereas a reverse RFP could remove this benefit.
f) Any excess energy over that required to serve the expected load serves as a hedge in the event switching is lower than expected and load is consequently higher than expected.

Drawbacks:

a) Prices may continue to fall thus increasing the magnitude that 2013/14 hedges are "out of the money".
b) Switching to ARES may be higher than forecast, thus increasing the magnitude of the excess hedge position, which if coincident with falling prices would increase the magnitude of the "out of the money" position.

4.2 ComEd

A similar table is shown for ComEd below. The ComEd figures also show a significantly over-hedged position for the 2013/2014 delivery year based on expected load projections. However, unlike Ameren, subsequent delivery years are not comparably over-hedged.

ComEd Expected Load and Current Hedge Position												
	Avg. Peak Contract Volumes						Avg. Off-Peak Contract Volumes					
Contract Month	Expected Load MW	2011 MW	2012 MW	20-YR MW	SB 1652 MW	Residual MW	Expected Load MW	2011 MW	2012 MW	20-YR MW	SB 1652 MW	Residual MW
Jun-13	1749	1,800	0	99	450	(600)	1406	1,250	0	102	450	(396)
Jul–13	2042	2,250	0	59	450	(717)	1623	1,800	0	83	450	(710)
Aug-13	1880	2,100	0	63	450	(733)	1499	1,650	0	105	450	(706)
Sep-13	1406	1,300	0	92	450	(436)	1139	1,050	0	101	450	(462)
Oct-13	1241	1,350	0	150	450	(709)	1016	1,100	0	180	450	(714)
Nov-13	1364	1,450	0	187	450	(723)	1159	1,250	0	196	450	(737)
Dec-13	1586	1,750	0	155	450	(769)	1372	1,250	0	146	450	(474)
Jan-14	1594	1,500	0	164	450	(520)	1391	1,300	0	180	450	(539)
Feb-14	1450	1,600	0	152	450	(752)	1277	1,400	0	167	450	(740)
Mar-14	1284	1,400	0	174	450	(740)	1124	1,250	0	194	450	(770)
Apr-14	1134	1,300	0	188	450	(804)	963	1,100	0	205	450	(792)
May-14	1147	1,350	0	196	450	(849)	960	1,100	0	162	450	(752)
Jun-14	1525	0	150	94	450	831	1236	0	0	106	450	680
Jul-14	1827	0	300	59	450	1,018	1459	0	100	83	450	826
Aug-14	1684	0	200	66	450	968	1359	0	50	101	450	758
Sep-14	1267	0	0	87	450	730	1025	0	0	105	450	470
Oct-14	1109	0	0	150	450	509	916	0	0	180	450	286
Nov-14	1230	0	0	197	450	583	1058	0	0	188	450	420
Dec-14	1461	0	100	148	450	763	1273	0	0	152	450	671
Jan-15	1468	0	100	172	450	746	1292	0	0	173	450	669
Feb-15	1341	0	50	152	450	689	1182	0	0	167	450	565
Mar-15	1188	0	0	166	450	572	1043	0	0	202	450	391
Apr-15	1039	0	0	188	450	401	893	0	0	205	450	238
May-15	1048	0	0	206	450	392	891	0	0	156	450	285
Jun-15	1417	0	0	94	450	873	1156	0	0	106	450	600
Jul-15	1709	0	0	59	450	1,200	1369	0	0	83	450	836
Aug-15	1575	0	0	66	450	1,059	1285	0	0	101	450	734

Sep-15	1184	0	0	87	450	647	964	0	0	105	450	409
Oct-15	1025	0	0	150	450	425	857	0	0	180	450	227
Nov-15	1154	0	0	197	450	507	995	0	0	188	450	357
Dec-15	1378	0	0	148	450	780	1200	0	0	152	450	598
Jan-16	1389	0	0	172	450	767	1226	0	0	173	450	603
Feb-16	1282	0	0	152	450	680	1129	0	0	167	450	512
Mar-16	1133	0	0	166	450	517	998	0	0	202	450	346
Apr-16	983	0	0	188	450	345	852	0	0	205	450	197
May-16	1006	0	0	206	450	350	851	0	0	156	450	245
Jun-16	1371	0	0	94	450	827	1103	0	0	106	450	547
Jul-16	1650	0	0	59	450	1,141	1340	0	0	83	450	807
Aug-16	1541	0	0	66	450	1,025	1231	0	0	101	450	680
Sep-16	1135	0	0	87	450	598	942	0	0	105	450	387
Oct-16	992	0	0	150	450	392	831	0	0	180	450	201
Nov-16	1127	0	0	197	450	480	974	0	0	188	450	336
Dec-16	1345	0	0	148	450	747	1176	0	0	152	450	574
Jan-17	1360	0	0	172	450	738	1205	0	0	173	450	582
Feb-17	1241	0	0	152	450	639	1102	0	0	167	450	485
Mar-17	1102	0	0	166	450	486	978	0	0	202	450	326
Apr-17	955	0	0	188	450	317	828	0	0	205	450	173
May-17	985	0	0	206	450	329	830	0	0	156	450	224
Jun-17	1346	0	0	94	450	802	1076	0	0	106	450	520
Jul-17	1617	0	0	59	450	1,108	1315	0	0	83	450	782
Aug-17	1504	0	0	66	450	988	1210	0	0	101	450	659
Sep-17	1103	0	0	87	450	566	919	0	0	105	450	364
Oct-17	970	0	0	150	450	370	810	0	0	180	450	180
Nov-17	1102	0	0	197	450	455	947	0	0	188	450	309
Dec-17	1309	0	0	148	450	711	1150	0	0	152	450	548
Jan-18	1331	0	0	172	0	1,159	1181	0	0	173	0	1,008
Feb-18	1208	0	0	152	0	1,056	1079	0	0	167	0	912
Mar-18	1071	0	0	166	0	905	952	0	0	202	0	750
Apr-18	934	0	0	188	0	746	806	0	0	205	0	601
May-18	961	0	0	206	0	755	807	0	0	156	0	651

5.0 MISO and PJM Resource Adequacy Outlook and Uncertainty

From the perspective of the IPA Procurement Plan, resource adequacy should be viewed from two different angles. First, in contrast to the era in Illinois when fully-integrated utilities built and rate-based generation under full Commission oversight, the process of acquiring resources under the post-Restructuring Act paradigm could be considered simply a function of determining what level of resources to purchase from which markets over time. However, in order for these markets to properly function, the market must provide sufficient resources to satisfy the demand of all users, and there should be sufficient incentives for resources to be available or forthcoming over the planning horizon to support a competitive market. Without such fully functioning markets, the IPA could be in the position to augment the current resource markets by, for instance, seeking longer-term purchases or PPAs to incent development of generation. This section reviews the likely load/resource outcomes over the planning horizon to determine, if indeed, 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 publically 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.
- Midwest ISO ("MISO"), which operates the transmission grid in most of central and southern Illinois.
- PJM Interconnect ("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. While uncertainties exist for the future, such as the implication of environmental standards, the best estimates at this time suggest it is highly probable that resources will be sufficient to meet the needs of Illinois customers without the need for the IPA to undertake any extraordinary actions. Regardless, the IPA will continue to actively monitor resource adequacy and future changes in electric markets that may require the IPA to reconsider its assessment.

5.1 North American Electric Reliably Corporation ("NERC") Reliability Assessments

NERC's most recent reliability assessments for MISO and PJM are reproduced in Table 5-1 and Table 5-2. For the IPA planning period (and well beyond), both MISO and PJM are projected to exceed the NERC planning reserve margin ("PRM") reference level.[79] While NERC uses a reference PRM of 15 percent, MISO calculates an even more conservative PRM. MISO's latest Loss of Load Expectation ("LOLE") studies imply a PRM that is slightly higher (17.4%).[80] Even so, MISO's anticipated PRM, shown on Table 5-5, far exceeds both the MISO and NERC reference PRM with the exception of summer 2018 through 2020, where MISO's anticipated PRM will meet or drop slightly below its own calculated reference PRM. The prospective and adjusted potential PRMs will continue to far exceed both the MISO reference level and the NERC reference PRM.[81] NERC also notes that there are no currently planned retirements in MISO that would significantly affect reliability and if, in the future, a retiring unit were to pose a reliability problem a "reliability mitigation plan" would be implemented until such time as alternatives become available.[82]

For PJM, NERC notes that PJM will meet its PRM for all of the planning periods with the exception of 2021 where it will be less than one percent deficient.[83] NERC notes that PJM has over 40,000 MW of nameplate generation in its interconnection queues. While PJM has identified 3,600 MW of generation retirements, as with MISO, if a retirement affects reliability a mitigation strategy will be put in place. PJM has identified no retirements significant to reliability as a result of recent environmental regulations.[84]

[79] The PRM provides an estimate of the excess of resources over the expected demand or load for a given period.
[80] A LOLE study is used establish the necessary reserves such that load is disconnected, on an expected basis, at some frequency. For example, the current standard for PJM, based on First Reliability Corporation rules, is one day in ten years or 0.1 days per year.
[81] "2011 Long-Term Reliability Assessment" NERC, November 2011, pp. 223-235
[82] Id. p. 225.
[83] PJM's PRM is also slightly higher than the NERC reference level based on PJM's LOLE studies. Id. p. 375
[84] Id. p. 379.

From these data one can conclude that it is highly probable that both MISO and PJM will continue to meet resource adequacy standards over the planning period and beyond.

Table 5-1. MISO Demand, Resources, and Reserve Margins—Summer and following Winter

Period (Summer and following Winter)	Demand		Capacity Resources			Planning Reserve Margins			
	Total Internal	Net Internal	Anticipated	Prospective	Adjusted Potential	Anticipated	Prospective	Adjusted Potential	NERC Reference Margin Level
	(MW)	(MW)	(MW)	(MW)	(MW)	(%)	(%)	(%)	(%)
2011	98,068	90,249	119,764	136,872	136,872	22.1%	39.6%	39.6%	15.0%
2011-2012	79, 052	71, 233	114, 870	131, 978	131, 978	45.3%	67.0%	67.0%	15.0%
2012	92,976	85,157	114,450	131,592	131,592	23.1%	41.5%	41.5%	15.0%
2012-2013	75,208	67,389	109,556	126,698	126,698	45.7%	68.5%	68.5%	15.0%
2013	94,834	87,015	114,509	131,651	131,651	20.7%	38.8%	38.8%	15.0%
2013-2014	77,410	69,591	109,615	126,757	126,757	41.6%	63.7%	63.7%	15.0%
2014	95,227	87,408	114,528	131,670	131,670	20.3%	38.3%	38.3%	15.0%
2014-2015	77,725	69,906	109,634	126,776	126,776	41.1%	63.1%	63.1%	15.0%
2015	95,947	88,128	114,551	131,693	131,693	19.4%	37.3%	37.3%	15.0%
2015-2016	78,574	70,755	109,657	126,799	126,799	39.6%	61.4%	61.4%	15.0%
2016	96,637	88,818	114,633	131,775	131,775	18.6%	36.4%	36.4%	15.0%
2016-2017	79,267	71,448	109,739	126,881	126,881	38.4%	60.1%	60.1%	15.0%
2017	97,332	89,513	114,633	131,775	131,775	17.8%	35.4%	35.4%	15.0%
2017-2018	79,992	72,173	109,739	126,881	126,881	37.2%	58.6%	58.6%	15.0%
2018	98,110	90,291	114,633	131,775	131,775	16.8%	34.3%	34.3%	15.0%
2018-2019	80,778	72,959	109,739	126,881	126,881	35.9%	57.1%	57.1%	15.0%
2019	99,010	91,191	116,196	133,338	133,338	17.4%	34.7%	34.7%	15.0%
2019-2020	81,577	73,758	111,302	128,444	128,444	36.4%	57.5%	57.5%	15.0%
2020	99,929	92,110	116,196	133,338	133,338	16.3%	33.4%	33.4%	15.0%
2020-2021	82,393	74,574	111,302	128,444	128,444	35.1%	55.9%	55.9%	15.0%
2021	143,485	135,199	200,308	200,308	200,308	39.6%	39.6%	39.6%	15.0%
2021-2022	83,217	75,398	111,302	128,444	128,444	33.7%	54.3%	54.3%	15.0%

Source:"2011 Long-Term Reliability Assessment" NERC, November 2011 Data from Tables 7 through 28

Table 5-2. PJM Demand, Resources, and Reserve Margins—Summer and following Winter

Period (Summer and following Winter)	Demand		Capacity Resources			Planning Reserve Margins			
	Total Internal (MW)	Net Internal (MW)	Anticipated (MW)	Prospective (MW)	Adjusted Potential (MW)	Anticipated (%)	Prospective (%)	Adjusted Potential (%)	NERC Reference Margin Level (%)
2011	148,941[(a)]	137,341	193,340	193,340	194,195	29.8%	29.8%	30.4%	15.0%
2011-2012	130,711	119,806	193,548	193,548	193,548	29.8%	29.8%	30.4%	15.0%
2012	158,603[(b)]	151,780	196,424	196,424	199,106	23.8%	23.8%	25.5%	15.0%
2012-2013	133,594	127,464	195,907	195,907	195,907	46.6%	46.6%	46.6%	15.0%
2013	162,489	153,510	200,244	200,244	203,310	23.2%	23.2%	25.1%	15.0%
2013-2014	135,529	127,243	199,712	199,712	199,712	47.4%	47.4%	47.4%	15.0%
2014	164,772	155,793	200,404	200,404	204,545	21.6%	21.6%	24.1%	15.0%
2014-2015	136,948	128,662	200,302	200,302	200,302	46.3%	46.3%	46.3%	15.0%
2015	166,506	157,527	200,990	200,990	206,142	20.7%	20.7%	23.8%	15.0%
2015-2016	137,985	129,699	200,308	200,308	200,308	45.2%	45.2%	45.2%	15.0%
2016	167,847	158,868	200,990	200,990	206,297	19.7%	19.7%	22.9%	15.0%
2016-2017	139,073	130,787	200,308	200,308	200,308	44.0%	44.0%	44.0%	15.0%
2017	169,443	160,464	200,990	200,990	206,522	18.6%	18.6%	21.9%	15.0%
2017-2018	140,040	131,754	200,308	200,308	200,308	43.0%	43.0%	43.0%	15.0%
2018	171,067	162,088	200,990	200,990	206,392	17.5%	17.5%	20.6%	15.0%
2018-2019	141,170	132,884	200,308	200,308	200,308	41.9%	41.9%	41.9%	15.0%
2019	172,780	163,801	200,990	200,990	206,723	16.3%	16.3%	19.6%	15.0%
2019-2020	81,577	73,758	111,302	128,444	128,444	36.4%	57.5%	57.5%	15.0%
2020	174,458	165,479	200,990	200,990	206,723	15.2%	15.2%	18.5%	15.0%
2020-2021	143,485	135,199	200,308	200,308	200,308	39.6%	39.6%	39.6%	15.0%
2021	176,060	167,081	200,990	200,090	206,723	14.2%	14.2%	17.4%	15.0%
2021-2022	144,621	136,335	200,308	200,308	200,308	38.5%	38.5%	38.5%	15.0%

Source: "2011 Long-Term Reliability Assessment" NERC, November 2011 Data from Tables 7 through 28
(a) Includes First Energy and Cleveland Public Power
(b) Includes Duke Ohio and Kentucky

5.2 MISO

While NERC uses data from MISO to conduct its assessment, MISO continues to update its analysis over time with its most recent long-term demand and capacity forecasts approved in December 2011. Total Internal Demand and Net Internal Demand are forecasted to grow to 100,926 MW and 96,717 MW by 2021. Net Internal Demand ranges from 88,765 MW in 2012 to 96,717 MW in 2021 with the reserve margin ranging from 24.5 percent to 16.1 percent over the same time period. The forecasted annual demand growth rate over the next ten years is approximately 1.0 percent, slightly increased from 2010. (Table 5-3)

Generator Interconnection Queue projects are expected to total approximately 7,000 MW of nameplate capacity by 2021, although only 2,549 MW is expected to be designated to serve MISO load by that time. Wind generators account for approximately 4,000 MW of nameplate capacity of the 7,000 MW amount. With the generator interconnection queue considered, Total Designated Capacity is projected to grow from 112,695 MW in 2012 to 114,749 MW in 2021. Internal Designated Capacity Resources are forecasted to be approximately 103,698 MW in 2012 and are assumed to be held constant through 2021. Behind-the-Meter Generation (3,608 MW in 2011) is treated as a capacity resource and not a load modifier, meaning it increases MISO's projected capacity rather than reducing its anticipated load. (Table 5-4) MISO's projection of PRMs is presented in Table 5-5 and is broadly consistent with the earlier NERC figures suggesting that MISO will maintain reliably throughout the planning horizon.

Table 5-3: MISO Load Projections 2012-2017

Demand (MW)	***2012***	***2013***	***2014***	***2015***	***2016***	***2017***
Unrestricted Non-Coincident	97,206	99,149	99,560	100,313	101,034	101,701
Est. Diversity	4,230	4,315	4,333	4,366	4,397	4,429
Total Internal	92,976	94,834	95,227	95,947	96,637	97,332
Direct Control Load Management	1,118	1,118	1,118	1,118	1,118	1,118
Interruptible Load	3,093	3,093	3,093	3,093	3,093	3,093
Net Internal Demand	88,765	90,623	91,016	91,736	92,426	93,121

Source: MISO 2011 Long Term Resource Assessment Table 1-1

Table 5-4: MISO Forecast Capacity 2012-2017

Capacity (MW)	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
Internal Designated Capacity Resources	103,698	103,698	103,698	103,698	103,698	103,698
External Designated Capacity Resources	4,894	4,894	4,894	4,894	4,894	4,894
Behind-the-Meter Generation	3,608	3,608	3,608	3,608	3,608	3,608
Future Planned Resources	495	862	881	904	986	986
Total Designated Capacity	***112,695***	***113,062***	***113,081***	***113,104***	***113,186***	***113,186***

Source: MISO 2011 Long Term Resource Assessment Table 1-1

Table 5-5: MISO Projected Reserve Margins 2012 - 2017

Reserve Margin	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
Reserve Margin (MW)	23,930	22,438	22,064	21,368	20,760	20,065
Reserve Margin (%)	27.0	24.8	24.2	23.3	22.5	21.5
Reserve Requirement (%)[7]	17.4	17.3	17.3	17.2	17.4	17.8

Source: MISO 2011 Long Term Resource Assessment Table 1-1

5.3 PJM

Summer peak load growth for the PJM RTO is projected to average 1.4% per year over the next ten years, and 1.3% over the next 15 years.[85] The PJM RTO summer peak is forecasted to be 176,420 MW in 2022, a 10-year increase of 22,638 MW. It reaches 185,294 MW in 2027, a 15-year increase of 31,512 MW.[86] Annualized 10-year growth rates for individual zones within PJM range from 0.9 to 1.9%.[87] Winter peak load for the PJM RTO is projected to average 1.2% per year over the next 10-year period, and 1.1% over the next 15 years.[88] The PJM RTO winter peak load in 2021/2022 is forecasted to be 144,836 MW, a 10-year increase of 15,996 MW, and reaches 150,901 MW in 2026/2027, a 15 year increase of 22,061 MW.[89] Annualized 10-year growth rates for individual zones within PJM range from 0.6% to 1.6%.[90]

PJM has a significant amount of generation waiting to be added for expected annual load increases. As of March, 2011, PJM had installed generating capacity of 166,292 MW. By the end of 2012, that will be 180,400 MW and by the end of 2013, 189,900 MW. By 2021, planned resources increase capacity by another 1,900 MW. PJM's generator interconnection queue has a total of 27,700 MW of on-peak conceptual capacity over the assessment period.

- Coal: 47.7% capacity
- Nuclear: 35.7% capacity
- Gas: 12% capacity
- 75,737 MW of capacity in generation request queues through 2018; of that, 37,579 MW is wind.

The PJM Reliability Pricing Model ("RPM") is built to encourage new investment to keep capacity reserves at roughly 15% for the PJM system. When existing generation retires, new generation should replace the lost capacity so that retirements should not create a threat to the overall PJM capacity reserves. The model determines capacity payments to generators; these are the payments for having excess capacity, not the price for energy actually being used by consumers. When there is more than 15% reserve capacity, the price of energy steadily lowers below PJM's calculation of the Cost of New Entry (NetCONE). When there is less than 15% reserve capacity the price increases, encouraging new investment up to 15%. There are price caps at 1.5x Net CONE, around 7% reserve capacity, meaning that when there is under 7% reserve capacity the price will not continue to increase.

The 2013/2014 Reliability Pricing Model (RPM) Base Residual Auction (BRA) cleared 152,743.3 MW of unforced capacity in PJM at a Resource Clearing Price of $27.73/MW-day.[91] This MW and price quantity pair on the RTO Variable Resource Requirement curve represents a 20.3% reserve margin; however when the Fixed Resource Requirement (FRR) load is considered the

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[85] PJM Load Forecast Report, January 2012, PJM Resource Adequacy Planning Department

[86] *Id.* at 1.

[87] *Id.* at 2.

[88] *Id.*

[89] *Id.*

[90] *Id.*

[91] PJM "2013/2014 RPM Base Residual Auction Results," PJM DOCS #592585, at 1.

actual reserve margin for the entire RTO is 20.2%.[92] The $27.73/MW-day RTO resource clearing price represents an increase of $11.27/MW-day from the 2012/2013 BRA.[93]

A total of 4,831.9 MW of incrementally new capacity in PJM was available for the 2013/2014 Base Residual Auction.[94] This incrementally new capacity includes new generation capacity resources, capacity upgrades to existing generation capacity resources, new Demand Resources, upgrades to existing Demand Resources, and new Energy Efficiency Resources.[95] The increase is partially offset by generation capacity derations to existing generation capacity resources to yield a net increase of over 2,907.8 MW of installed capacity.[96]

The total quantity of Demand Resources offered into the 2013/2014 BRA was 12,952.7 MW (UCAP) which represents an increase of 3,105.1 MW (32%) over the Demand Resources that offered into the 2012/2013 BRA. Approximately 72% (9,281.9 MW) of these Demand Resources cleared in the auction. Part of this increase (1,384.8 MW) occurred in the new ATSI transmission zone that is participating for the first time in the Base Residual auction due to the ATSI integration. The remaining 1,720.3 MW increase was in the remaining zones of the market. The majority of the increased participation by demand response was driven by the forward capacity market incentives.

The total quantity of Energy Efficiency (EE) Resources offered into the 2013/2014 BRA was 756.8 MW (UCAP) which represents an increase of 33% over the EE Resources that offered into the 2012/2013 BRA. Approximately 90% (679.4 MW) of these EE Resources cleared in the auction.

Table 5-6 summarizes the offer and resultant data for each cleared Base Residual Auction from 2008/09 through the 2013/2014 Delivery Years, and includes all resources located in the RTO (including all LDAs within the RTO) and notes the capacity located outside the PJM footprint that was offered into the auction.[97]

Table 5-6: RPM Base Residual Auction Generation, Demand, and Energy Efficiency Resource Information

Auction Supply (all values in ICAP)	2008/2009	2009/2010	2010/2011	2011/2012**	2012/2013	2013/2014***
Internal PJM Capacity	166,037.9	167,026.3	168,457.3	169,241.6	179,791.2	195,633.4
Imports Offered	2,612.0	2,563.2	2,982.4	6,814.2	4,152.4	4,766.1
Total Eligible RPM Capacity	**168,649.9**	**169,589.5**	**171,439.7**	**176,055.8**	**183,943.6**	**200,399.5**
Exports / Delistings	4,205.8	2,240.9	3,378.2	3,389.2	2,783.9	2,624.5
FRR Commitments	24,953.5	25,316.2	26,305.7	25,921.2	26,302.1	25,793.1
Excused	722.0	1,121.9	1,290.7	1,580.0	1,732.2	1,825.7
Total Eligible RPM Capacity - Excused	**29,881.3**	**28,679.0**	**30,974.6**	**30,890.4**	**30,818.2**	**30,243.3**
Remaining Eligible RPM Capacity	***138,768.6***	***140,910.5***	***140,465.1***	***145,165.4***	***153,125.4***	***170,156.2***

92 *Id.*

93 *Id.*

94 *Id.*

95 *Id.*

96 *Id.*

97 *Id.* at 12.

Generation Offered	138,076.7	140,003.6	139,529.5	143,568.1	142,957.7	156,894.1
DR Offered	691.9	906.9	935.6	1,597.3	9,535.4	12,528.7
EE Offered	0.0	0.0	0.0	0.0	632.3	733.4
Total Eligible RPM Capacity Offered	**138,768.6**	**140,910.5**	**140,465.1**	**145,165.4**	**153,125.4**	**170,156.2**
Total Eligible RPM Capacity Unoffered	***0.0***	***0.0***	***0.0***	***0.0***	***0.0***	***0.0***

*RTO numbers include all LDAs.

**All generation in the Duquesne zone is considered external to PJM for the 2011/2012 BRA.

***2013/

The incremental effect of total capacity additions and reductions to date is summarized on the table below from the 2007/2008 to the 2013/2014 BRAs.[98] A total of 4,831.9 MW of incrementally new capacity in PJM was available for the 2013/2014 BRA, and this incrementally new capacity includes new generation capacity resources, capacity upgrades to existing generation capacity resources, new Demand Resources, upgrades to existing Demand Resources, and new Energy Efficiency Resources.[99] The increase is partially offset by generation capacity derations to existing generation capacity resources to yield a net increase of 2,907.8 MW of installed capacity.[100]

This table also illustrates the total amount of resource additions and reductions over seven Delivery Years since the implementation of the RPM construct. Over the period covering the first seven RPM Base Residual Auctions, 11,582 MW of new generation capacity was added which was partially offset by 7,184.7 MW of capacity derations or retirements over the same period.[101] Additionally, 12,966.5 MW of new Demand Resources were offered over these last seven auctions, and 733.4 MW of new Energy Efficiency resources were offered in the 2013/2014 auction.[102] The total net increase in installed capacity in PJM over the period of the last seven RPM auctions was 17,887.3 MW.

Table 5-7: Incremental Capacity Resource Additions and Reductions to Date

Capacity Changes (in ICAP)	2007 - 2008	2008 - 2009	2009 - 2010	2010 - 2011	2011 - 2012	2012 - 2013	2013 - 2014	Total
Increase in Generation Capacity	602.0	724.2	1,272.3	1,776.2	3,576.3	1,893.5	1,737.5	11,582.0
Decrease in Generation Capacity	-674.6	-375.4	-550.2	-301.8	-264.7	-3,093.9	-1,924.1	-7,184.7
Net Increase in Demand Resource Capacity**	555.0	574.7	215.0	28.7	661.7	7,938.1	2,993.3	12,966.5
Net Increase in Energy Efficiency Capacity**	0	0	0	0	0	632.3	101.1	733.4
Net Increase in Installed Capacity	**482.4**	**923.5**	**937.1**	**1,503.1**	**3,973.3**	**7,160.1**	**2,907.8**	**17,887.3**

* RTO numbers include all LDAs

** Values are with respect to the quantity offered in the previous year's Base Residual Auction. **Does not include Existing Generation located in ATSI Zone

98 *Id.* at 14-15.

99 *Id.* at 14.

100 *Id.*

101 *Id.*

102 *Id.*

On May 18, 2012, PJM announced the results of its annual Reliability Pricing Model (RPM) for capacity three years forward, to meet the needs of the June 1, 2015 to May 31, 2016 delivery year. This auction procured a record amount of new generation in one year, 4900 MW. In addition, capacity imported from west of PJM increased about 8% to 4335 MW. Overall, the auction procured 164,561 MW of capacity resources at a base price of $136 per MW. This compares to PJM's all-time peak up to that time of 158,448 MW. In addition to new generation, most of it natural gas–fired, the capacity auction procured record amounts of demand response, energy efficiency and renewable generation. These results indicate that the PJM capacity market construct is providing the incentive for new generation and reliability, even in the face of coal retirements.[103]

The utilization of the capacity resources procured is dependent on the strength of the transmission system connecting the generators to the grid. As a complement to the RPM auction results, PJM announced on May 17, 2012 the approval of nearly $2 billion in electric transmission upgrades related to generation retirements, consisting of over 130 projects. The upgrades allow for safe and reliability flow of electricity from other sources to replace retiring generation.

5.4 Resource Adequacy Uncertainty and Environmental Regulation

While it appears from published material that resources are likely to remain adequate through the planning period, the uncertainty most likely to impact resource adequacy is new environmental regulation. New regulations requiring capital investments for some facilities such as the Cross State Pollution Rule and the National Emission Standards for Hazardous Air Pollutants have the potential to force a subset of those plants to retire, potentially degrading reliability and/or raising prices for capacity. NERC considers this to be the most significant resource adequacy risk in the coming one to five years.[104] Several entities have attempted to address the issue of environmental regulation-fueled facility retirements by looking at the likely retirement of plants as a result. For example, PJM recently examined the projected impacts of US EPA regulation on coal retirement.[105] Several conclusions are of importance include that:

- Some capital investment will be required with as much as thirty-seven percent of the total coal capacity in PJM requiring at least two retrofits.[106]
- Even with almost 7,000 MW less coal capacity clearing for the 2014/2015 delivery year, PJM estimates the RTO will carry a reserve margin of 19.6 percent for the delivery year.[107]
- Even with the potential retirement of coal capacity already there are also announced commitments to replace a portion of that capacity with new gas-fired capacity such that the PJM would still carry a reserve margin at or above of the target 15.3 percent installed reserve margin.

Add the potential for new entry from demand resources, as has been the trend in recent years, and resource adequacy does not appear to be threatened in PJM. Although no system-wide capacity problem is apparent in PJM, the report noted that localized reliability concerns could arise given the

[103] "PJM Capacity Auction Secures Record Amounts of New Generation, Demand Response, Energy Efficiency", PJM press release, May 18, 2012.
[104] 2011 Long-Term Reliability Assessment" NERC, November 2011, p. 72.
[105] "Coal Capacity at Risk: Potential Impacts of the Finalized EPA Cross State Air Pollution Rule and Proposed National Emissions Standards for Hazardous Air Pollutants," PJM, August 26, 2011
[106] Id. p. i.
[107] Id. p. iv.

location of particular units and the unique locational services they provide such as congestion management of particular transmission facilities and voltage support for the transmission system. . In PJM's assessment, the key is whether replacement resources or transmission reinforcements can be timely added given the breadth of the potential retirements and the pressure on outside vendors to supply new turbines and related resources. PJM noted that as long as resource adequacy and local reliability are assured, the cycle of generation retirement and new resource entry are market-driven outcomes that can be reliability and efficiency enhancing. Newer, more efficient generation resources that replace retiring generation may have lower forced outage rates and thus, are more dependable than older generation resources that may be nearing the end of their useful lives. Additionally, new resources, whether it is new generation, demand response, or energy efficiency, may also provide lower cost alternatives to achieve resource adequacy.

MISO has undertaken its own study and determined that roughly 13,000 MW that could be at risk and -- under the most extreme scenario -- planning margins could fall below acceptable rates without additional resources added.[108]

However, decisions to retire generating plants hinge on a myriad of factors. For example, the sharp decline in natural gas prices, the rising cost of coal and reduced demand for electricity are all contributing to company decisions to retire some of the country's oldest power plants. As noted by Susan Tierney[109], in the 3/20/12 blog ***Politico***[110],

> "Most of the coal-fired power plants in line for retirement are, in fact, of typical retirement age. Many are between 50-60 years old; some are as old as 70. Many are "merchant" plants, whose financial performance is shaped by competitive markets. The bottom line comes down to economic fundamentals: Power companies just can't operate these older coal-fired plants and produce electricity at high enough prices to make money in today's conditions. The chief executive officer of American Electric Power, which owns a big fleet of coal-fired plants in Ohio, said as much recently when he explained a series of coal plant retirements to Wall Street analysts. He said that the coal plant closures involved "high cost plants," *which didn't run often anyway* (emphasis added), because it was more economical to use natural gas and other plants in the company's fleet. Shutting down the coal plants, he said, would mean costs savings."

Similarly, with respect to new coal construction,

> "Consumers Energy, for example, announced on Dec. 2 the cancellation of the 830-megawatt Bay City coal project. The Michigan utility said it was cancelling the project because of the same factors that led it to defer the project in May 2010. The factors are reduced customer demand for electricity due to the condition of the economy, surplus generating capacity in

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[108] "EPA Impacts from the EPA Regulations on MISO," MISO, October 2011, p.

[109] *Susan Tierney is a managing principal at Analysis Group, a business strategy firm that consults on energy and other issues. She is a former assistant secretary for policy at the Energy Department and former secretary of environmental affairs of Massachusetts.*

[110] http://www.politico.com/news/stories/0312/74211.html

> the Midwest and lower natural gas prices linked to expanded shale gas supplies. Lower natural gas prices make new coal-fired plants less economically attractive."[111]

NERC suggests that even in areas where retirements occur, there are options for mitigation that include advancing in-service dates of new generation, increases in transfers between regions, increased demand-side management, use of more gas-fired generation or re-powering coal units with combined cycle turbines, among other options.[112]

5.5 Overall Conclusions for Illinois

The RTO-based reliability assessments examined above are important measures of supply reliability in Illinois, because the Illinois electric grid operates within the control of the RTOs. The integration of Entergy into MISO this November will provide more generation to be dispatched and bid into the MISO markets, and the same can be said of the successful integration of Duke Energy Ohio and Duke Energy Kentucky into PJM. On a more local level, while the announced or actual retirement of several coal-fired units around the State were newsworthy events, including the Fisk and Crawford generating stations located in central Chicago, based on the IPA's familiarity with the in-state generating resources, Illinois appears to have an in-state generating portfolio that is better situated than most because of its early adoption of, and action to achieve, clean air targets, as well as the non-coal diversity of its generating stock, including nuclear and wind. Coupled with a relatively robust transmission system, overall, and proactive transmission planning in anticipation of coal plant retirements, the base case planning scenario for resource adequacy indicates sufficient reliable capacity to meet system reliability targets for the planning horizon. Given this conclusion, the IPA does not need to include any extraordinary measures in the 2013 Procurement Plan to assure reliability over the planning horizon.

6.0 Managing Supply Risks

The IPA 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…[113]

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 IPA's Procurement Plan include:

> [A]n 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.[114]

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[111] A Path Forward for Coal, CARBON CAPTURE KEY, Published In: EnergyBiz Magazine. March/April 2012, Barry Cassell
[112] 2011 Long-Term Reliability Assessment" NERC, November 2011, p. 75-76
[113] 20 ILCS 3855/1-5(A)
[114] 220 ILCS 5/16-111.5(b)(3)(vi)

In other words, the challenge for the IPA in its procurement plans is to balance supply and demand in a given electric market environment, both wholesale and retail, with a goal towards achieving the lowest total cost over time, taking into account any benefits of price stability. The 2013 Procurement Plan, however, faces particular challenges as described below.

This is the IPA's fifth procurement plan. The prior four Plans appropriately assessed the various risk factors applicable to Ameren Illinois and ComEd supply for fixed price default service and resulted in a pre-existing portfolio consisting of laddered standard product supply contracts of varying short-term durations of from one month to one year, supplemented by longer term 20-year contracts from a December 2010 procurement for bundled RECS and energy, and a legislatively-mandated procurement conducted in February 2012 for a delivery period extending through December 2017. As shown in Section 3 of this 2013 Procurement Plan, these pre-existing contracts cover a majority of the supply requirements over the planning horizon. While the preponderance of supply needs have already been met (at least from the perspective of this Procurement Plan), there remain three key categories of risk at the forefront of impact on this specific procurement plan:

1. Market price uncertainty at the wholesale level
2. Supply volume uncertainty at the wholesale level
3. Demand volume uncertainty at the retail level

None of these categories operates without affecting the other categories of risks. As discussed in Sections 3 and 5, wholesale prices affect the quantity of wholesale supply, and both, in turn, affect retail prices and the retail demand for utility fixed price service relative to the demand for ARES retail service. Utilities in restructured markets such as Illinois are particularly burdened with demand volume risk, given the nature of their service obligations.[115] In contrast, an ARES can opt to control, to some degree, the demand volume uncertainty (and its wholesale market price risk) by locking in a portfolio of retail customers for a period of time with some certainty before locking in its supply resources and costs, or creating contractual protections against customers attempting to leave before parallel supply contracts end. Hence, an ARES is better able to control its supply and demand balance. That is one of the underlying factors why an ARES price offer under municipal aggregation is generally held open only for periods as short as a few hours. Neither Ameren Illinois nor ComEd have that luxury under the PUA. The utilities maintain an obligation to serve all default service customers and must be prepared to serve an uncertain range of load that may leave or return at will, subject to some restrictions. Hence, wholesale suppliers bidding to serve utility load are likely to include a volume premium in their price offers.[116] A standard energy block product was designed, in large part, to shift that risk back to the ratepayers, on the theory that the utilities (working in conjunction with the IPA and Commission) could address this risk with a lower premium than the competitive market.

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[115] *See*, *e.g.*, 220 ILCS 5/16-103(c) ("Notwithstanding any other provision of this Article, each electric utility shall continue offering to all residential customers and to all small commercial retail customers in its service area, as a tariffed service, bundled electric power and energy delivered to the customer's premises consistent with the bundled utility service provided by the electric utility on the effective date of this amendatory Act of 1997"); 220 ILCS 5/16-103(d) ("Any residential or small commercial retail customer which elects delivery services [*i.e.* leaves the IPA portfolio] is entitled to return to the electric utility's bundled utility tariffed service offering [*i.e.* return to the IPA portfolio] provided in accordance with subsection (c) of this Section upon payment of a reasonable administrative fee which shall be set forth in the tariff").

[116] Note that both utilities and ARES are subject to the same weather and economic risk. For purposes of this Procurement Plan, it is customer migration risk coupled with the obligation to serve that creates a differential risk between utility and ARES supply portfolios.

Beyond traditional customer-by-customer switching, migration risk due to municipal aggregation introduces an unprecedented potential for volume volatility for both the Ameren and ComEd supply portfolios. Historically, mismatches between the standard products purchased for the supply portfolio and the actual load serving responsibility at the time of delivery have been covered through utility transactions in the day-ahead and real-time balancing markets of MISO and PJM. However, it is necessary to examine the costs of this supply/demand balancing strategy against other solutions, given the current high potential volumes of mismatch. The costs of this strategy are paid by customers through a purchased electricity adjustment, rather than the base supply charge. This adds a level of volatility and unpredictability to supply charges, implicating one of the principles the legislature has articulated for the supply portfolio – price stability.

A number of procurement strategies have been proposed by parties in prior procurement plan approval proceedings at the Commission as means to mitigate certain perceived risks, such as the risk of rising market prices exacerbated by hypothesized resource scarcity. Below, this 2013 Procurement Plan examines the following portfolio risk management strategies in light of current and projected market conditions:

1. The role and risks of long-term contracts vs. short-term supply within the planning horizon.
2. Full-requirements supply as an alternative to reliance on the daily MISO and PJM balancing markets.
3. Demand response as a risk management tool.

In considering risk management strategies, there is no one portfolio strategy that is "optimal", although there can be a portfolio that has an optimal expected cost for a given set of risks. Therefore, the level of risk that each strategy optimally addresses must be understood.

6.1 Market Conditions

In order to understand the factors that create market price uncertainty and supply risks, the IPA conducted a set of modeling scenarios incorporating a range of assumptions with respect to system load, natural gas prices, demand response capability and carbon regulation compliance costs. A base case scenario covering the entire 5-year planning horizon was constructed, while high and low cases were examined over the typical 3-year procurement cycle. A key conclusion is that market prices in Illinois, as measured by Locational Marginal Prices (LMPs) are relatively insensitive to variability of the key inputs listed above. This conclusion means that portfolio strategy decisions can be made in an environment of a relatively well-defined bandwidth of market price projections. This is important because of the IPA's mandate to propose and conduct procurement strategies designed to foster low and stable prices over time.

Modeling of LMPs for Illinois was preformed utilizing a stochastic optimization program that simulates the operations of the electric system.[117] The modeling uses generator data, transmission data, and hourly load data to simulate the outcomes of system operation over the relevant planning horizon and over the entire Eastern Interconnect. As with any modeling of future outcomes, the choice and evolution of different variables can have significant effects on modeled outcomes. In order to obtain an understanding of how LMPs are likely to evolve over time in Illinois in the short term, the modeling results reported here reflect eight different possible

[117] Simulations completed using MarSi. For a more complete description of MarSi *see* "Annual Report: The Costs and Benefits of Renewable Procurement in Illinois under the Illinois Power Agency and Illinois Public Utilities Act," IPA, March 30, 2012, Appendix 3.

futures and one base case. While often this type of modeling is used to make inferences over a long planning horizon e.g., 20 years, in which future conditions are likely to change, given the relative short-term nature of the planning exercise undertaken here, the range of possible outcomes represented by the scenarios below are likely to represent the extremes of ranges of actual outcomes. Table 6.1 illustrates the changes in the key variables considered over possible futures.

Table 6.1: Scenarios for Modeling Illinois LMPs 2013-2017

	Load	**Gas Prices**	**Demand Response**	**Emissions Prices**
Scenario 0: Base Case	Base Case – Based on FERC estimates	NYMEX futures for 2013; escalated at 4%	Embedded in Forecast	CO_2 = $5/ton NOx = $10,000/ton
Scenario 1: Robust Economy	Base Case + 5% (energy growth)	Base Case	Base Case	Base Case
Scenario 2: Frail Economy	Base Case - 10% (energy growth)	Base Case	Base Case	Base Case
Scenario 3: High NG Prices	Base Case	Base Case +10%	Base Case	Base Case
Scenario 4: Low NG Prices	Base Case	Base Case -10%	Base Case	Base Case
Scenario 5: Demand Response I	Base Case	Base Case	Base Case -5% peak demand	Base Case
Scenario 6: Demand Response II	Base Case	Base Case	Base Case -10% peak demand	Base Case
Scenario 7: Carbon Constrained I	Base Case	Base Case	Base Case	CO_2 = $10/ton NOx = $10,000/ton
Scenario 8: Carbon Constrained II	Base Case	Base Case	Base Case	CO_2 = $20/ton NOx = $10,000/ton

One potential risk factor for the IPA portfolio is escalating short-term market prices in which the balancing of the IPA load is done. Using the above futures, the LMPs for the NI-Hub region (defined by 234 nodes in the ComEd territory) and the IL-Hub (defined by 150 nodes in the Ameren Illinois territory) were estimated for the Base Case and the eight scenarios for 2013-2015 and for the base case out to 2017.[118] In the short-term, both the IPA's planning model and PJM forecast LMPs for NI-Hub to increase, on average, modestly over the next three years as shown in Table 6.2.

Table 6.3 provides the same data for the IL Hub. The IL Hub LMPs in the Base Case appear to move even less than what is expected in NI Hub.

Table 6.2: NI-Hub Expected LMPs (2013-2017) - $/MWh

Year	Peak (Base Case)	Off-peak (Base Case)	Peak (Adica Forecast)[(a)]	Peak (NYMEX Futures) [(a)]
2013	41.62	35.16	39.09	35.69
2014	42.47	35.60	39.54	36.57
2015	43.61	36.35	39.99	37.31
2016	45.32	37.34		
2017	46.87	38.46		

(a) Source: Adica produced forecast based on hourly historical day-ahead LMP of PJM-NI-Hub

(b) Source: September 10. 2012, NYMEX Daily Settlements for PJM Northern Illinois Hub

[118] Note that Ameren and ComEd do not necessarily settle their MISO and PJM loads at NI-Hub or IL-HUB but this analysis serves as a useful proxy and comparison for LMP growth projections between the two utility service areas .

Table 6.3: IL-Hub Expected LMPs (2013-2017) - $/MWh

Year	Peak (Base Case)	Off-peak (Base Case)
2013	38.04	33.01
2014	38.85	33.61
2015	39.64	34.35
2016	41.22	35.29
2017	42.11	36.24

Note: MISO is in the process of preparing an Updated LMP Forecast

Figure 6.1 and Figure 6.2 present the results of the modeling in a slightly different manner. Here the ranges of the average monthly (peak) prices are shown for NI-Hub and IL-Hub respectively. The ranges are relatively tight over the three-year period. It is worth noting here that, one extreme Scenario (Carbon Constrained II) has been excluded for this comparison as representing an extremely unlikely outcome in the near term (although perhaps not in the long-term). [119]

[119] Many forecasters assume that carbon will not be priced until after 2017 in base and low case forecasts. In high forecasts carbon prices are likely to begin under $20/ton until at least 2017 (2010 USD). *See e.g.*, "2011 Carbon Dioxide Price Forecast," August 10, 2011 Synapse Energy Economics, Inc. (Table 3) This report also reviews assumptions used in utility planning exercises across the country. In nearly all plans filed before 2011 carbon prices were expected to exceed $20/ton by 2013-2015 (at least in high price scenarios). Those plans filed after 2010, however, typically assume carbon prices exceeding $20/ton only in high price scenarios during this time. It seems likely that carbon will not be priced until 2015 given the time needed to implement rules and the likelihood that the economic situation will not improve in the coming year.

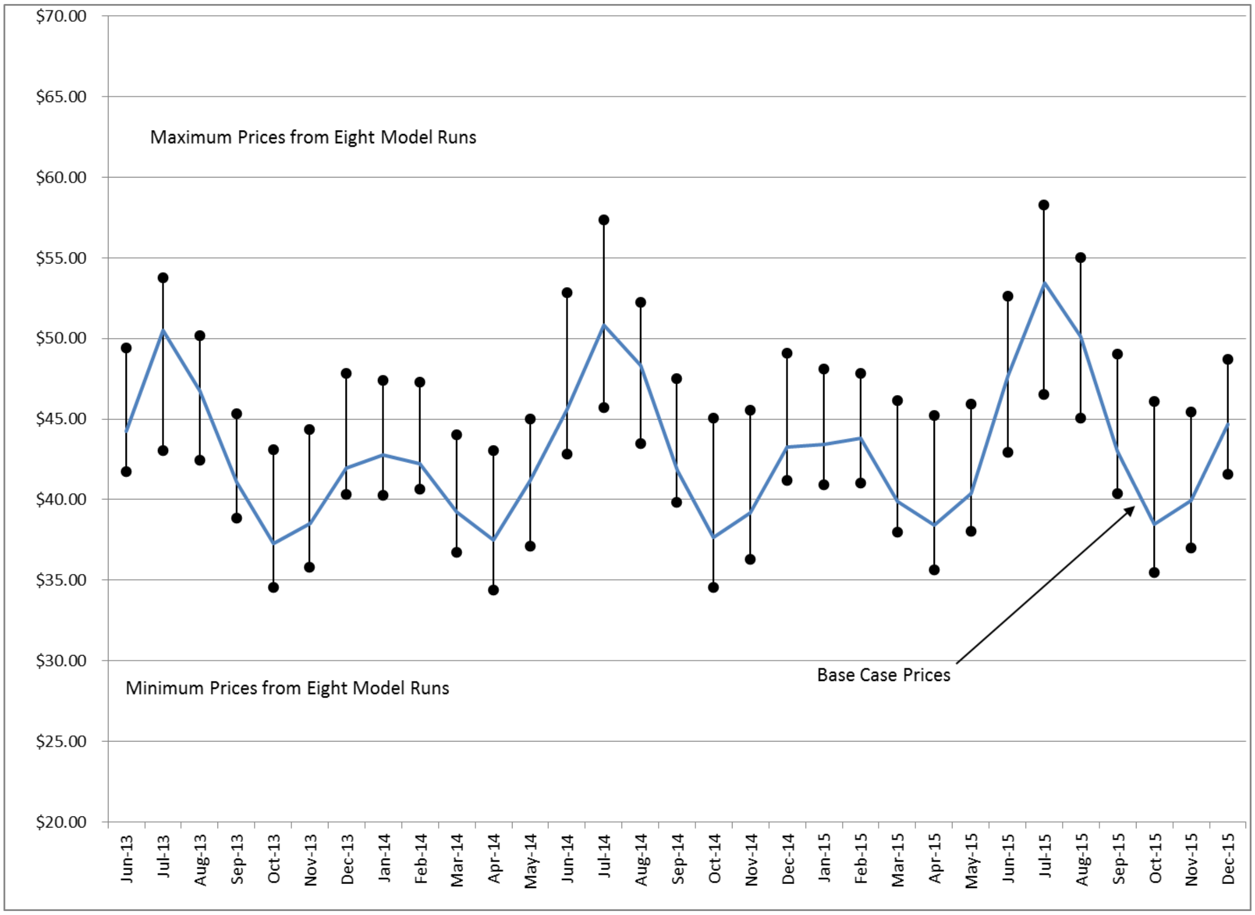

Figure 6.1: Range of Estimated Monthly Average Peak Prices in the Northern Illinois Hub during 2013-2015 ($/mWh)

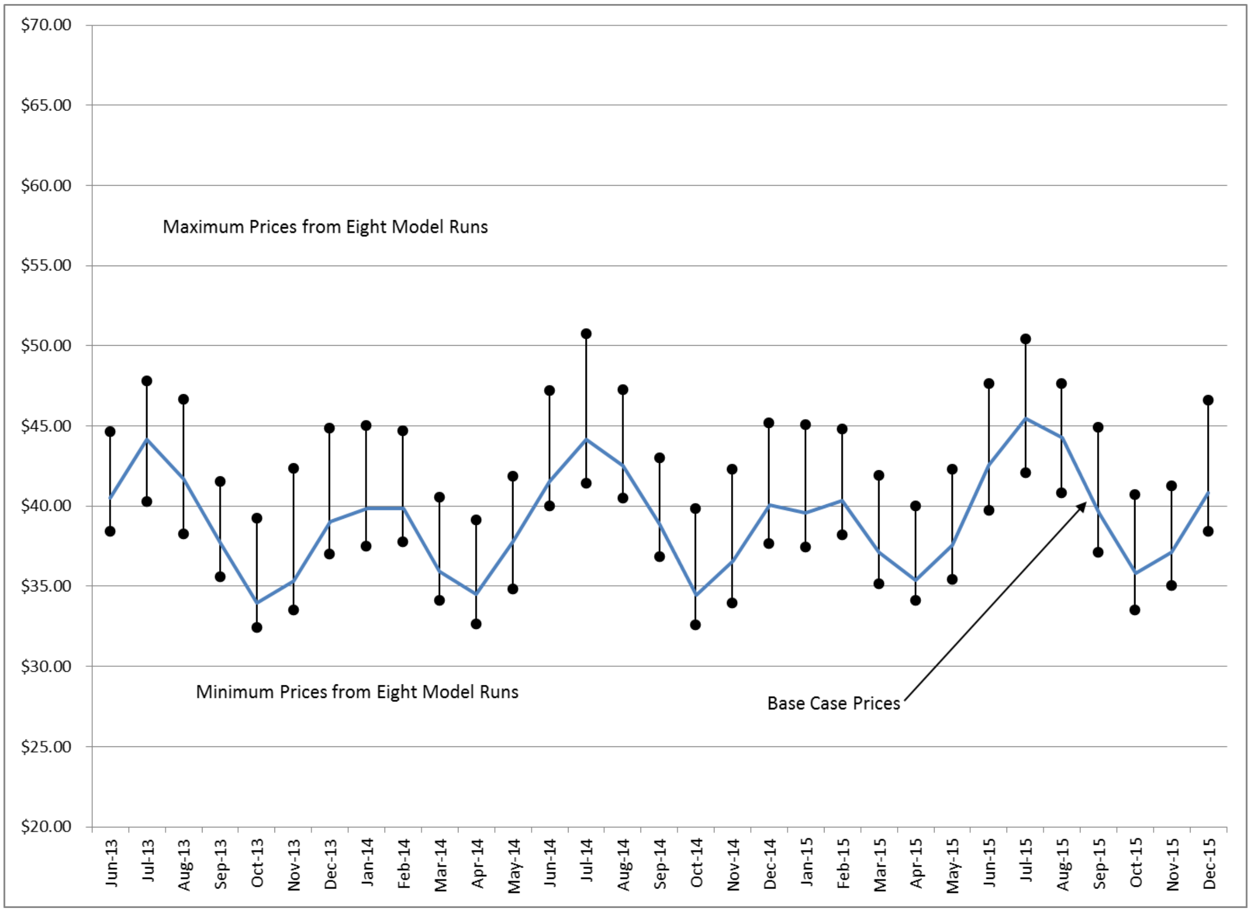

Figure 6.2: Range of Estimated Monthly Average Peak Prices in the Illinois Hub during 2013-2015 ($/mWh)

In the past, the IPA has been concerned about volatility issues that could affect the overall prices paid by customers. The current procurement portfolios already subject customers to some degree of market volatility due to the nature of existing standard block products, which require balancing in the day-ahead market. Additionally, other factors, such as uncertainty concerning utility load requirements suggest that the IPA refrain from recommending additional block energy purchases at this time. The magnitude of quantity risk can be illustrated by reviewing the utilities' compliance forecasts. For example, the ComEd load forecasts have become increasingly volatile largely due to the uncertainty associated with municipal aggregation and to a lesser extent other customer migration issues. For the past two compliance forecasts (2011 and 2012) the differences between the high and low forecast for the first year have expanded dramatically. In 2011 the difference was 85 percent (for 2012-2013). The current forecast shows a 103 percent difference between the high and the low forecast for the first year (2013-2014). For the out years the forecast variation is even wider. The same is true for Ameren. With this type of quantity risk, and the likelihood that market prices will remain soft for the immediate future, it could be prudent to reduce the use of fixed quantity products to hedge portfolio supply as Staff and others have suggested.

6.2 Role and Risks of Long-Term Contracts vs. Short-Term Supply Within the Planning Horizon

Long-term contracts have been characterized as a strategy to incentivize new build, ensure adequate supply, and lock in prices, thus providing reliability and price stability. Is the current IPA-procured portfolio strategy of relying largely on a ladder of short-term contracts appropriate in a future where there are projections of large-scale plant retirements due to promulgation of clean air rules? Section 5 of this Plan describes the PJM and MISO resource adequacy analyses, and concludes that over the 5-year planning horizon the risks of resource shortfalls that might jeopardize reliability are largely mitigated by actions taken by both RTOs, including transmission improvements as well as capacity market incentives. That being said, should the IPA propose a strategy of greater reliance on using long-term contracts as either a price hedge in the face of expected market-price increases or to incentivize new generation that would otherwise be incapable of being financed without a long term power purchase agreement? These arguments are often promulgated on behalf of renewable resources and other generation with economic development opportunities in Illinois. However, this procurement analysis must take place, not in the abstract, but in the context of the pre-existing supply portfolio and current retail and wholesale market conditions.

First, this Plan describes the means by which MISO and PJM operate to optimize additions to the generation supply in their respective market and reliability regions. Then an assessment of the role of additional long-term contracts in the Ameren and ComEd supply portfolios is provided.

6.2.1 Optimizing Timing of New Build for Economics, Reliability and Uncertainty

Building new generating capacity in either PJM or MISO is subject to many conditions and constraints—amount of existing capacity, coal retirements due to age and/or cost of air pollution control costs due to the Cross-State Air Pollution Rule (CSAPR), Mercury and Air Toxics Standard (MATS) and National Ambient Air Quality Standards (NAAQS), delivered fuel prices (coal and natural gas), and market rules for capacity additions. All of the factors are embedded in the bid price of capacity submitted in either the PJM or MISO auction market.

PJM

PJM relies on its Reliability Pricing Model - annual capacity auctions for capacity resources three years into the future plus residual auctions for resources needed one and two years out, calculations of the Cost of New Entry (CONE) and a price screen known as the Minimum Offer Price Rule (MOPR) designed to assure that generators bid on an equal footing - to secure cost-effective capacity resources and to incent new construction to bid into the auctions when it makes economic sense.

The basic premise of the capacity auction system in PJM is to have pricing interact with the targeted reserve margin level so that the closer the supply/demand intersection reaches the targeted reserve margin (15.4%) the more capacity prices will reflect the required economics for new generators. In theory, capacity prices at the target reserve margin level of the supply/demand curve would reach sufficient levels to incentivize new peaker construction, calculated as the Net Cost of New Entry (Net CONE). It is important to recognize the auction itself is structurally designed with a view towards constructing gas-fired peakers; decisions regarding baseload generation remain tied to the underlying energy price outlook, as their high load factors dictate that this is where the bulk of the their revenues and margin is achieved.

The calculations of MOPR and CONE are detailed and complex. In fact, CONE is calculated separately for each of 5 CONE Zones. ComEd is in CONE Area 3, along with AEP, APS, ATSI, Dayton, DEOK, and Duquesne. These calculations serve much like the benchmarks used to screen bids in the IPA-administered procurement process rather than setting minimum and maximum bids. It appears that within PJM, natural gas-fired capacity (either combustion turbines or combined cycle) is currently economically viable, and is being/will be bid into regional markets if the capacity is required and/or it is lower cost on the margin than existing capacity.

PJM has a system to procure capacity resources designed to provide appropriate price signals that will reach the level necessary to bring new resources to the marketplace when it is economically the optimum time to do so. While the capacity market only looks three years into the future, in theory robust capacity, energy and ancillary services markets will, in a mature marketplace, provide a steady stream of revenues over the useful life of the generating asset, thus allowing the asset to be financed and built. In practice, project developers still desire the certainty that long term power purchase agreements provide in terms of revenue streams sufficient to support the total carrying costs of a project. However, in a retail choice state such as Illinois, finding a wholesale customer with a 20-year portfolio horizon is difficult due to the uncertain outlook for the level of steady-state retail load to be served by the wholesale purchase. For a utility in such a volatile load position, care must be taken so that the supply portfolio is not over-burdened with strandable long-term contract costs. Fortunately for generators, the Illinois generation marketplace has access to both the MISO and PJM markets, providing a wealth of opportunity for sales to electricity counterparties other than ComEd and Ameren, including traditional vertically integrated utilities that retain an obligation to serve all customers in their service area and, therefore, more certain load serving obligations. The interconnected system is indifferent to the financial transactions of generators and their customers, only that sufficient supply and demand balance exists electrically at all times. It should not matter who the customer is – the lights will still stay on.

MISO

The MISO capacity market is much less developed than is PJM's and still subject to significant evolution over the next several years. MISO is slated to host its inaugural annual capacity auction in late March 2013, for the 2013/2014 planning year. It is a voluntary auction, unlike PJM's mandatory auction, and the preponderance of MISO members are vertically integrated utilities. Further, the MISO capacity markets construct places much of its emphasis on motivating vertically-integrated utilities to "opt-out" of participation via filing fixed resource adequacy plans (FRAPs). This design orientation is a result of a FERC order (to MISO) to remove its proposed MOPR provisions from its tariff. The signals to incent new build and compensate generator developers in the MISO marketplace come less from the MISO capacity construct and more from the vertically-integrated utilities that predominate the MISO region and that can rate base new assets over their economically useful lives.