State of Illinois
Pat Quinn, Governor

ILLINOIS POWER AGENCY

2012 Power Procurement Plan
September 28, 2011
Updated pursuant to the Illinois Commerce Commission's December 21, 2011 Order in ICC Dkt. No. 11-0660

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1.0 Executive Summary

Pursuant to Public Act 095-0481[1] ("IPA Act"), the Illinois Power Agency ("IPA" of "Agency") submits this annual electricity procurement plan (the "Plan") to the public for comment.

This document and its attachments comprise the fourth Final Plan prepared by the IPA. The IPA Act requires that a Draft Plan and subsequent Final Plan be prepared annually. The procurement methods and specifications recommended in this Plan are designed to fulfill the requirements of the Act to "ensure adequate, reliable, affordable, efficient, and environmentally sustainable electric service at the lowest total cost over time…"[2]

The annual Plan's purpose is to detail procurement approaches that will secure electricity commodity and associated transmission services, plus required renewable energy assets to meet the supply needs and obligations of the eligible retail customers served by Ameren Illinois Company ("Ameren") and Commonwealth Edison Company ("ComEd" and jointly the "Utilities"). Public comments and recommendations on the proposals contained in the Draft Plan were sought, and considered prior to the submittal of this Final Plan to the Illinois Commerce Commission.

This Plan outlines a procurement strategy for the period of June 2012 through May 2017 based on detailed 5-year supply forecast requirements provided by the Utilities (see Attachments A and B). Because existing contracts are in place to satisfy a portion of the consumer load requirements, procurement activities considered in this Plan are limited to meeting the residual consumer demand not covered by those contracts.

The Plan presents the following core procurement elements:

- **Request for Proposals.** The procurement events are organized around a two-stage process governed by a Request for Proposal ("RFP") for each wholesale product sought. The first stage of each RFP will establish a pool of qualified bidders; the second stage will solicit price bids for scheduled volumes of wholesale product.
- **Price and Volume solicitations.** The RFPs will request bids for fixed price and fixed volume contract offers.
- **Schedule.** The IPA proposes to hold the procurement events during the early spring of 2012 to secure the volumes of wholesale products identified in this Plan.
- **Procurement Administrators.** The IPA proposes to extend the contracts of the current procurement administrators: National Economic Research Associates (to administer the ComEd solicitations), and Levitan and Associates (to administer the Ameren solicitations).
- **Products.** The IPA proposes to seek bids for wholesale products:
  - **Energy Supply Resources –** Supply will be sought for the Ameren and ComEd loads on a laddered three-year forward basis in volumes described in this Plan.
  - **Capacity Resources –** Capacity Resources for ComEd will be delivered primarily through the PJM capacity markets. For Ameren, Capacity Resources that are qualified by the Midwest Independent System Operator ("MISO") to issue Planning Resource Credits ("PRC") will be sought for the Ameren load.
  - **Renewable Energy Resources** – Renewable Energy Credits ("REC") for multiple compliance years will be sought. Due to potential customer migration and the structure of the Long-Term Power Purchase Agreements for renewable energy in effect for the 2012-2013 through 2032-2033 compliance periods, specific annual Renewable Resource Budgets are variable. The proposed process will establish a confidential budget threshold for a 10 year budget horizon, and utilize those budgets to structure REC contracts consistent with the solar and wind carve-outs specified in the Renewable Portfolio Standard. IPA will seek to establish common REC contract terms including unsecured credit limits for creditworthy REC suppliers, unless an alternative proposal is acceptable to the procurement administrators, the utilities, the IPA, Commission Staff and the procurement monitor.

2.0 Introduction and Overview

The Illinois Power Agency ("IPA") is required by statute to meet the electricity supply needs of the bundled rate customers of Commonwealth Edison ("ComEd") and Ameren Illinois Company ("Ameren"). It does so by developing and implementing electricity procurement plans designed to "ensure adequate, reliable, affordable, efficient and

[1] Referred to as the Illinois Power Agency Act, or "IPA Act".
[2] 220 ILCS 5/16-111.5(d)(4).

environmentally sustainable" electric service at the "lowest total cost over time,"[3] while taking into account "any benefits of price stability."[4] In the 2012-2013 planning year, the IPA portfolios will supply approximately 40 million MWH to almost 4.5 million "eligible customers" of ComEd and Ameren.[5]

Illinois is in transition from an industry dominated by vertically integrated public utilities to one that relies on deregulated generation and wholesale commodity markets. To optimize portfolio design, the IPA must closely monitor wholesale electricity markets, particularly the PJM Interconnection ("PJM"), in which ComEd participates, and the Midwest Independent System Transmission Operator ("MISO"), in which Ameren participates.[6] In addition, the IPA must also closely monitor the retail markets in Illinois to understand the scale and scope of its tasks. The dynamic nature of these unique and evolving wholesale and retail markets poses challenges to efficient and effective procurement planning.

2.1 Background. In 1997, the Illinois General Assembly passed the Electric Service Customer Choice and Rate Relief Act, legislation that restructured electricity markets and phased in a competitive power market in Illinois. All customers of ComEd and Ameren were given the legal option to purchase electricity from Alternative Retail Energy Suppliers ("ARES") or from their local utility. Regardless of energy supplier, the Utilities were obligated to provide customers non-discriminatory delivery services. The 1997 law created a "mandatory transition period" during which retail electricity rates were reduced and then frozen, and the Utilities were allowed to transfer or sell generation assets to affiliated companies or third parties. The transition period was extended in subsequent legislation through the end of 2006. After a series of proceedings, the Commission entered Orders approving the Utilities' proposals, as modified, to procure power after the transition period through a full requirements reverse auction. The auctions were conducted in fall 2006, and electricity rates for customers buying power from the Utilities were adjusted to reflect those costs as of January 2007.

SB 1592[7] was approved by the General Assembly and signed into law in the summer of 2007. In addition to providing $1 billion in temporary rate relief to consumers, and creating renewable energy and energy efficiency standards, it created the IPA to develop and manage a new power procurement process. Beginning on June 1, 2008, the Utilities were required to procure all power for eligible retail customers ("Eligible Retail Customers") who purchase electricity from the Utilities according to a Plan developed by the IPA and approved by the Commission.

The PUA provides for generation service to be declared competitive for classes of customers when the Commission finds sufficient evidence that competition for generation service within a customer class meet certain legal standards. Certain classes have been declared competitive as a matter of law by action of the General Assembly.

All ComEd commercial and industrial ("C&I") customer classes with demand greater than 100kW are deemed competitive, as are Ameren customers with demand of at least 400kW. However, the law allowed ComEd customers with demand below 400kW, and Ameren customers with demand between 400kW and 1000 kW to continue to purchase power and energy from the utility at bundled utility service rates through May 30, 2010. The law provided that no customer in a class declared competitive is allowed to return to bundled utility service after having switched to an alternative provider. This Plan reflects current competitive declaration status. ComEd and Ameren will procure power for customers in classes deemed competitive only in the hourly spot market and passing through those variable market prices to the competitively declared customers that choose not to select supply service from an ARES.

Increasing the role of competitive supply options within all rate classes served by the Utilities has been supported by recent developments and statutes:

- The Office of Retail Market Development (ORMD) within the Illinois Commerce Commission continues to pursue its mission to "actively seek input from all interested parties and to develop a thorough understanding and critical analyses of the tools and techniques used to promote retail competition in other states. The Office shall monitor existing competitive conditions in Illinois, identify barriers to retail competition for all customer classes, and actively explore and propose to the Commission and to the General Assembly solutions to overcome identified barriers." Some recent ORMD activities include:

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[3] 20 ILCS 3855/1-5.

[4] *Id*.

[5] "Eligible customers" are defined by law as those retail customers that purchase power and energy from the electric utility under fixed-price bundled service tariffs. 220 ILCS 5/16-111.5(a). These are customers that take both delivery and supply service from their electric utility.

[6] PJM interconnection coordinates the movement of wholesale electricity in all or parts of 13 states and the District of Columbia, including the ComEd service territory. MISO coordinates the movement of wholesale electricity in all or parts of 11 Midwestern states, including the Ameren service territory.

[7] Public Act 095-0481

- o Rulemaking for Obligations of Retail Electric suppliers and Internet Enrollment
- o Renewable Portfolio and Clean Coal Standards for Alternative Retail Electric Suppliers and Utilities operating outside of their service areas.
- o Development of an online "Price to Compare" service of Illinois Consumers to research retail price offers from Alternative Retail Electric Suppliers operating in the Ameren and Commonwealth Edison region at http://www.pluginillinois.org/fixedrate.aspx

- Local communities are moving forward with Municipal Aggregation plans. Municipal Aggregation occurs when local communities select an Alternative Retail Electric Supplier for the eligible retail customers that reside within their municipal boundaries. The following communities have taken direct steps to establish their own aggregations:

TABLE A: CURRENT STATUS OF MUNICIPAL AGGREGATION IN ILLINOIS

Community	Status
Campton Hills	Referendum Passed
Crest Hill	Supplier - Direct Energy, Rate - 5.89 cents per kWh through September 2013
Elburn	Supplier - Direct Energy, Rate - 5.99 cents per kWh through October 2012
Erie	Supplier - Nordic Energy Services, Term - 3 years
Fox River Grove	Supplier - Direct Energy, Rate - 5.99 cents per kWh through September 2013
Fulton	Supplier - FirstEnergy Solutions, Rate - 6.23 cents per kWh (residential) through July 2014
Glenwood	Supplier - Direct Energy, Rate - 5.99 cents per kWh through September 2013
Grayslake	Supplier - Integrys, Rate - 5.52 cents per kWh, Term - 2 years
Harvard	Supplier - Direct Energy, Rate - 5.99 cents per kWh through September 2013
Lincolnwood	Supplier - Integrys, Rate - 5.52 cents per kWh, Term - 2 years
Milledgeville	Supplier -FirstEnergy Solutions, Rate - 5.90 cents per kWh, Term - 3 years
Morris	Supplier - FirstEnergy Solutions, Rate - 5.43 cents per kWh through September 2013
Mount Morris	Supplier - FirstEnergy Solutions, Rate - 5.88 cents per kWh, Term - 32 months
New Lenox	Supplier -Direct Energy, Rate - 5.89 cents per kWh through September 2013
North Aurora	Supplier -Integrys, Rate 5.75 cents per kWh (residential), Term - 2 years
Oak Brook	Supplier - Integrys, Rate - 5.52 cents per kWh, Term - 2 years
Oak Park	Supplier – Integrys, Rate – 5.79 cents per kWh; Term – 2 years.
Polo	Supplier - FirstEnergy Solutions, Rate - 5.83 cents per kWh, Term - 32 months
Sugar Grove	Supplier -Direct Energy, Rate - 5.99 cents per kWh through September 2013
Wood Dale	Supplier - FirstEnergy Solutions, Rate - 5.92 cents per kWh, Term - 30 months

Based on these and other indicators (e.g. the number of ARES registered with the ICC, and the number of ARES registering with intent to sell into the residential sector), the IPA anticipates that the policy supporting competitive electricity markets will continue and strengthen, and that a portion of the eligible retail consumers currently served through the IPA portfolio will migrate towards ARES options.

2.2 Procurement Approach. Public Act 095-0481, which includes the IPA Act and certain modifications to the Public Utilities Act ("PUA") was signed into law on August 28, 2007. The IPA Act identifies four primary activities to be undertaken by the Agency:

(1) *develop electricity procurement plans to ensure adequate, reliable, affordable, efficient, and environmentally sustainable electric service at the lowest total cost over time, taking into account any benefits of price stability, for electric utilities that on December 31, 2005 provided electric service to at least 100,000 customers in Illinois. The procurement plans shall be updated on an annual basis and shall include electricity generated from renewable resources sufficient to achieve the standards specified in the Act.*

(2) *conduct competitive procurement processes to procure the supply resources identified in the procurement plan, pursuant to Section 16-111.5 of the Public Utilities Act.*

(3) develop electric generation and co-generation facilities that use indigenous coal or renewable resources, or both, financed with bonds issued by the Illinois Finance Authority.
(4) supply electricity from the Agency's facilities at cost to one or more of the following: municipal electric systems, governmental aggregators, or rural electric cooperatives in Illinois.[8]

This is the fourth Plan submitted by the IPA in accordance with the Section 16-111.5 of PUA. This Plan considers the procurement strategy for the period of June 2012 through May 2017. The Plan applies to the following Utilities: Ameren Illinois Company ("Ameren"), and Commonwealth Edison ("ComEd" and jointly the "Utilities").

The IPA Act requires that the Plan include the following general components:

Each procurement plan shall analyze the projected balance of supply and demand for eligible retail customers over a 5-year period with the first planning year beginning on June 1 of the year following the year in which the plan is filed. The plan shall specifically identify the wholesale products to be procured following plan approval, and shall follow all the requirements set forth in the Public Utilities Act and all applicable State and federal laws, statutes, rules, or regulations, as well as Commission orders[9]

Specific inclusions to the Plan are noted as follows in the IPA Act:

(1) Hourly load analysis. This analysis shall include:
(i) Multi-year historical analysis of hourly loads;
(ii) Switching trends and competitive retail market analysis;
(iii) Known or projected changes to future loads; and
(iv) Growth forecasts by customer class.
(2) Analysis of the impact of any demand side and renewable energy initiatives. This analysis shall include:
(i) the impact of demand response programs, both current and projected;
(ii) supply side needs that are projected to be offset by purchases of renewable energy resources, if any; and
(iii) the impact of energy efficiency programs, both current and projected.
(3) A plan for meeting the expected load requirements that will not be met through preexisting contracts. This plan shall include:
(i) definitions of the different retail customer classes for which supply is being purchased;
(ii) the proposed mix of demand-response products for which contracts will be executed during the next year. The cost-effective demand-response measure shall be procured whenever the cost is lower than procuring comparable capacity products, provided that such products shall:
(A) procured by a demand-response provider from eligible retail customers;
(B) 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;
(C) provide for customers' participation in the stream of benefits produced by the demand-response products;
(D) provide for reimbursement by the demand-response provider of the utility for any costs incurred as a result of the failure of the supplier of such products to perform its obligations thereunder; and
(E) meet the same credit requirements as apply to suppliers of capacity, in the applicable regional transmission organization market;
(iii) monthly forecasted system supply requirements, including expected minimum, maximum, and average values for the planning period;
(iv) the proposed mix and selection of standard wholesale products for which contracts will be executed during the next year, separately or in combination, to meet that portion of its load requirements not met through pre-existing contracts, including but 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;
(v) proposed term structures for each wholesale product type included in the proposed procurement plan portfolio of products; and
(vi) an assessment of the price risk, load uncertainty, and other factors that are associated with the proposed procurement plan; this assessment, to the extent possible, shall include an analysis of the

8 20 ILCS 3855/1-20.
9 220 ILCS 5/16-111.5(b).

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.

(4) Proposed procedures for balancing loads. The procurement plan shall include, for load requirement included in the procurement plan, the process for:

(i) hourly balancing of supply and demand; and,

(ii) the criteria for portfolio re-balancing in the event of significant shifts in load[10].

This Plan meets the requirements of the IPA Act.

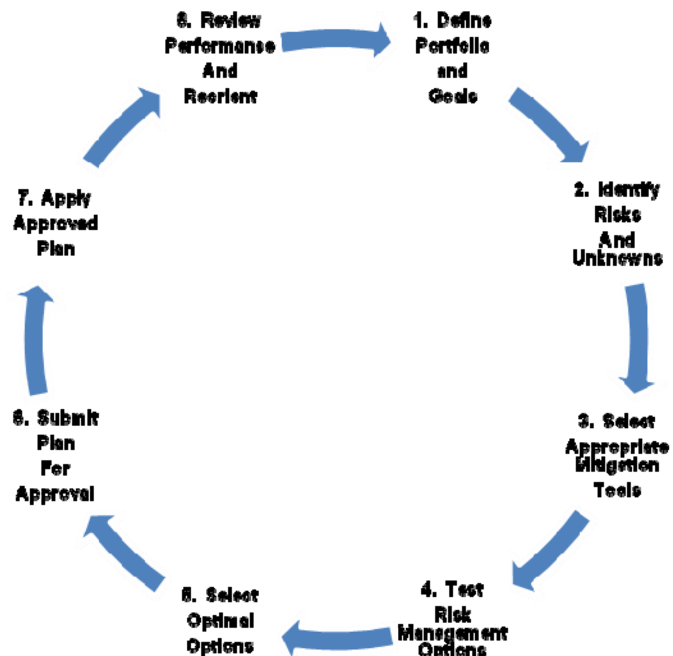
2.3 Planning Process. This Plan proposes to secure pricing and supplies of electricity commodities, and required transmission services to meet the supply requirements for Eligible Retail Customers of Ameren and ComEd. Additionally, it proposes a plan to meet the Illinois Renewable Portfolio Standard ("RPS") for those same Eligible Retail Customers. This Plan also addresses RPS compliance methods for hourly rate customers of the Utilities.

As noted above, the IPA must submit a Plan each year identifying projected loads for Eligible Retail Customers, and a plan for fulfilling those load requirements. Per the PUA, Eligible Retail Customers are defined as:

> *[T]hose retail customers that purchase power and energy from the electric utility under fixed-price bundled service tariffs, other than those retail customers whose service is declared or deemed competitive under Section 16-113 and those other customer groups specified in this Section, including self-generating customers, customers electing hourly pricing, or those customers who are otherwise ineligible for fixed-price bundled tariff service.[11]*

The IPA Act requires that a Plan be submitted annually and that the IPA consider a five-year time horizon when formulating its Plan. The IPA has adopted a continuous-cycle planning process that responds to changing information and market conditions. The diagram below outlines the general stages of the IPA procurement planning process.

FIGURE 1: IPA PROCUREMENT PLANNING PROCESS



1. **Define Portfolio and Goals.** The IPA works with Utilities to define the size of the electricity needs to be supplied by the Plan. Other stakeholders also have opportunity for input into the IPA planning agenda.
2. **Identify Risks and Unknowns.** Market conditions and other factors are reviewed to identify elements that present the potential for increasing consumer prices.
3. **Select appropriate mitigation tools.** Procurement methods and products to most effectively and efficiently mitigate immediate and long-term risks are identified.

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

[11] 220 ILCS 5/16-111.5(a).

4. **Test risk management options.** Statistical models to test the performance and value of identified risk mitigating options are developed and deployed.
5. **Select optimal options.** Products and procedure most suitable for delivering the lowest and most stable costs to the Portfolio are selected.
6. **Submit for approval.** IPA submits the Plan for approval by ICC.
7. **Apply Approved plan.** IPA, Procurement Administrator, and the Utilities coordinate procurement according to the approved Plan.
8. **Review Plan performance and reorient.** Performance of the Plan with regard to prices and stability is closely monitored, and subsequent Plans are reoriented to address current market conditions, new risks and opportunities.

The IPA Act requires several steps in the Plan approval process. A timeframe for those steps is presented in Table B.

TABLE B: PROPOSED IPA PLAN SUBMISSION AND AUTHORIZATION SCHEDULE

Planning Activities	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11
1. Utilities Submit Load Projections	X					
2. IPA Prepares Draft Plan						
3. IPA Submits Draft Plan		X				
4. Public Comment Period						
5. Final Plan submitted to ICC			X			
6. Objections filing period						
7. ICC Hearings determination						
8. ICC review of Plan						
9. ICC confirms or modifies Plan						X

1. **Utilities Submit Load Forecasts.** The IPA Act requires the Utilities to submit detailed hourly projections of the load to be supplied by the Utilities ("Load Forecast"). The projections extend out for five years and are adjusted for customer switching, as well as Utility-sponsored Demand Response, and Energy Efficiency Programs. The Ameren five-year projections were received by the IPA on July 15, 2011, and the ComEd five-year projections were received by the IPA on July 13, 2011.
2. **IPA Prepares Draft Plan.** The IPA prepared this Draft Plan for publication on the IPA website at www.illinois.gov/ipa for the purposes of alerting the public of the procurement methods the IPA is considering prior to formal submittal to the Illinois Commerce Commission.
3. **IPA Submits Preliminary Plan.** The Preliminary Plan was made available to the public for comment on the ICC and IPA websites on August 15, 2011.
4. **Public Comment Period.** The Preliminary Plan was made available to the public for comment. As required by the PUA, during the 30-day period allowed for utilities and other interested entities to submit comments on the IPA's draft plan, the IPA held two public hearings for the purpose of receiving public comment on the procurement plan.
   a. **Friday, September 9, 2011: Springfield** at the Illinois Commerce Commission, 527 East Capital Avenue in the Main Hearing Room from 10am – 1pm. The Commission's audio webcast was used during this meeting.

   b. **Tuesday, September 13, 2011**: **Chicago** at the Illinois Commerce Commission, 160 North LaSalle, 8th Floor Main Hearing Room from 10am – 1pm. The Commission's webcast was not be available for this meeting.
5. **Final Plan Submission to ICC.** A Final Plan was prepared by the IPA in consideration of the comments received during the public comment period and filed with the Illinois Commerce Commission on September 28, 2011.
6. **Objections Filing Period.** Objections to the Plan must be filed within five (5) days after the plan is filed.
7. **ICC Hearings Determination.** ICC has ten (10) days after the plan is filed to determine whether hearings on the Plan are required.
8. **ICC Review of Final Plan.** ICC may take up to ninety (90) days to review the Final Plan.

9. **ICC Approves a Procurement Plan.** The Final Plan is either approved by a vote of the ICC, or an alternative to the IPA Final Plan is approved by the ICC. The Final Plan was approved by the ICC on December 21, 2011 through its Order in ICC Docket No. 11-0660.

The IPA Act requires the following activities in order to execute the recommendations contained in the approved Plan. A timeframe for those steps is presented below in Table C below.

TABLE C: PROPOSED IPA PROCUREMENT EXECUTION SCHEDULE

Procurement Activities	Oct-11	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12
1. Procurement Administrator contracts renewed	X								
2. RFP and systems developed									
3. RFP Released					X				
4. Procurement Event Preparation									
5. Procurement Events									
6. Supply Contracts Executed									
7. Procured Products Delivery Begins									

1. **Procurement Administrator contract renewed.** The IPA Act requires that the IPA retain the services of one or more Procurement Administrators to facilitate execution of the Plan. This third party entity serves as a coordinator of the bidding and contracting activities between the Utilities, bidders, the IPA and the ICC. The IPA Act allows the IPA to retain the services of procurement administrators under one-year contracts with a single one-year extension option. The IPA retained the services of National Economic Research Associates and Levitan and Associates in spring 2011. The IPA intends to execute one-year extensions on those contracts in October 2011.
2. **RFP and Systems Developed.** The Procurement Administrator must develop and submit a series of standard bidder qualifications, submittal documents, industry standard contracts, and bid evaluation forms and methods to facilitate the issuance of the RFP required by the IPA Act.[12]
3. **RFP Released.** Upon completion of the required preparations and authorizations, the Procurement Administrator will issue a series of RFP's to potential wholesale bidders. Bids will be submitted according to the standard products specifications developed by the Procurement Administrator, the Utilities, and the IPA.
4. **Procurement Event Preparation.** The Procurement Administrator will be required to establish methods and platforms to facilitate bidding on defined electricity products. The Procurement Administrator also will be required to facilitate capacity procurement as well as the purchase of renewable energy requirements as specified in the approved Plan.
5. **Supply Contracts Executed.** The Procurement Administrator has two days to submit a confidential recommendation regarding whether the low bids meet market-based benchmarks and should be accepted. The ICC then has two days to accept or reject the recommendations, and the utility then has three days to sign bilateral supply agreements with successful bidders.
6. **Procured Products Delivery Begins.** Physical delivery under the supply contracts secured through the spring 2012 procurement events will commence in June of 2012 (later in the case of some contracts). These new contracts will supplement financial and physical hedges already in place via legacy contract. These legacy contracts include the contracts that resulted from the 2010 and 2011 IPA procurement cycles, as well as certain financial swap contracts alluded to within the PUA[13] and executed in 2007 contemporaneously with passage of the IPA Act.

2.4 Portfolio Design.

The IPA is responsible for developing and implementing a Plan to secure electricity supplies for Eligible Retail Customers for Ameren and ComEd. The schedule of monthly electricity volumes to be purchased and prices for those volumes is based on the IPA portfolio design. The IPA Act provides the priorities for the portfolio design are:

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

[13] See Subsection (k) of Section 111.5 of the Public Utilities Act (220 ILCS 5/16-111.5(k)), added by Public Act 095-0481, which also created the IPA Act. These swap contracts are between the utilities and their affiliates and did not require Commission approval. They predate the first IPA plan and were not the result of a Commission approved competitive procurement process.

"… 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."[14]

The challenge inherent in the IPA's charge is to achieve low and stable prices in a market where prices change constantly and sometimes dramatically. Complicating the task are variables that may significantly increase or decrease IPA Portfolio requirements over the short term (such as weather) or over the longer term (such as customer migration away from the IPA portfolio).

Designing the portfolio requires an appreciation of the variables that drive price and load fluctuation, and the extent to which those variables can affect price. For the purposes of the IPA's analysis and planning, risk is defined as any market condition that has the potential of elevating or lowering prices relative to the fixed price contracts secured through the IPA process. Risk is also defined as any change in the size of the load of eligible retail customers served through the IPA portfolio.

After completing its portfolio design exercise, the IPA proposes the schedule of purchases of wholesale products to meet the needs of eligible customers.

2.4.1 Risk Discussion. The PUA identifies the primary categories of risk exposure to the portfolio when it requires the IPA to include in the Plan the following:

> *"an assessment of the price risk, load uncertainty, and other factors that are associated with the proposed procurement plan; this assessment, to the extent possible, shall include an analysis of the following factors: contract terms, time frames for securing products or services, fuel costs, weather patterns, transmission costs, market conditions, and the governmental regulatory environment; the proposed procurement plan shall also identify alternatives for those portfolio measures that are identified as having significant price risk."*[15]

The following is not an exhaustive list of risks that can affect the IPA portfolio, as market developments can create, eliminate, or reorder known risks.

2.4.1.1 Price Risk. All elements of the portfolio are exposed to price risk on two primary levels: (1) long-term cost trend risk, and (2) short-term clearing risk. The movement of physical electricity prices is due to the primary costs and risks in the electricity sector: fuel, plant efficiency, transmission, and capital investments driven by plant additions and environmental compliance all interact against variable market demand and are reflected in the day-ahead and real time prices yielded by the regional wholesale markets. These real time price patterns translate roughly into future prices for electricity as reflected in financial markets. Mitigating long-term price risk is achieved by taking multiple positions within the market. Within the context of the IPA portfolio, multiple positions are taken within the market by following a laddered approach to securing fixed price electricity contracts at different times over a medium term horizon. Some have rightly observed that while this approach can lessen the impact of accelerating prices, it also slows the delivery of benefits of falling prices. However, mitigating price risk carries a premium, and the IPA maintains that its approach provides necessary protection against longer term price volatility and escalation.

Short-term clearing risk occurs when excess electricity purchased on behalf of the portfolio is not used and is sold back to the market at a loss, or when electricity above the projected volumes is required, and additional volumes must be purchased from the market at spot prices that might be high relative to the average price of electricity already secured for the portfolio. Short-term risks are largely mitigated through the use of load averaging and securing monthly contracts against those load averages.

2.4.1.2 Load Uncertainty. The portfolio is exposed to load uncertainty risk due to inelasticity of demand among many portfolio participants, and the unknown pace of migration of eligible customers to ARES suppliers over time. As noted in the above, the policy of the State of Illinois is to support electricity choice and competitive retail markets with the IPA portfolio of fixed price contracts serving as the "default" rate provider.
Consumption by bundled service customers is relatively inelastic, meaning that consumption does not diminish significantly when prices are high. This is due in large part to current tariff structures that do not expose customers to price variance. Inelasticity of demand represents risk insofar as portfolio participants

[14] 220 ILCS 5/16-111.5(d)(4).
[15] 220 ILCS 5/16-111.5(b)(3)(v).

who do continue to use large volumes of electricity when prices are high (e.g., running air conditioning units during hot summer afternoons) do not carry the full direct cost of their usage. Instead, the cost of their consumption during high cost periods is averaged across the entire portfolio. Inclusion of demand response and energy efficiency and distributed solar PV as alternative products within the IPA procurement events could serve as effective tools in addressing price responsiveness and load shape.

Outside of recently competitively declared rate classes, competitive supply has only recently taken hold in the broader Residential market in Illinois. However, recent developments indicate that significant reductions to the barriers to retail competition in residential markets are on the near-term horizon.

Migration of eligible retail customers to ARES suppliers presents risk to the portfolio insofar as migration can cause cost spiraling under certain conditions. For example, assume that a high percentage of anticipated long-term load requirements for the IPA portfolio were secured with fixed volume contracts. Further, assume that market prices decreased in the future (e.g. our recent market experience in 2008-2009). Finally, assume that migration from the IPA portfolio to an ARES was free of barriers.

In such a situation, higher-than-market bundled rates available through the IPA portfolio would motivate switching by those customers who could be profitably served by ARESs at the relatively lower current market prices. As the number of bundled service customers eroded, those remaining on bundled rates would effectively be paying not only for the cost of their consumption, but also the costs of disposing of the volumes secured for customers who have switched to other suppliers. And while the Purchase of Receivables ("POR") is designed to prevent cherry-picking of customers by ARES, there is the potential that those who do migrate will be larger, more creditworthy, and responsive to marketing; leaving behind smaller, relatively poorer and more remote consumers. For this reason, laddering-in purchases over time enables the IPA to minimize risk for consumers by allowing it to adjust procurement volumes in response to changing customer needs and market conditions.

2.4.1.3 Contract terms. Contract terms related to credit requirements for the bidders and the Utilities may increase direct and indirect costs due to the premiums associated with providing credit facilities that are ultimately borne by the und-use customer. However, it is necessary to obtain such credit requirements from the bidders in order to protect end-use customers from potentially far higher costs that could be incurred in the event of a supplier default.

Collateral Thresholds should remain at the levels used in the Utilities' existing 2011 energy contracts unless there is consensus among the utilities, Procurement Administrators, Procurement Monitor and Staff that a compelling reason warrants new Collateral Thresholds. Under no circumstances should implementing new Collateral Thresholds require retroactive changes that lower the Collateral Thresholds in existing contracts entered into during past or current procurement processes.

2.4.1.4 Time Frames for securing products and services. Time frames for securing products and services present risk to the portfolio insofar as the underlying volatility in electricity markets places a premium on time. Compliance with the PUA leads to the following general calendar when a single procurement event is considered:

- July – Load Forecasts submitted by Utilities to IPA
- August – IPA submits Plan to ICC
- September – Public comment period
- October – Final Plan submittal
- December – ICC authorization of substitution
- Spring – Procurement event held
- June - Deliveries commence

This schedule has yielded procurement events that occur several months after load projections are made and eight months after the initial Plan is developed. Changes in load due to retail switching and other factors, and changes in market conditions during that extended period could limit the value of the forecasts and expose customers to unnecessary risk. In the 2010 and 2011 procurement processes, revised load projections from the Utilities were submitted in response to downward projections in load requirements due to economic weakness within the region.

The portfolio design recommended by the IPA focuses on mitigating upside price risk, however, as seen in recent periods, prices in the wholesale market can and do move down. This being the case, the IPA recommends continuing the practice of laddered procurement over a three-year period in the cases of energy and capacity resources on an annual basis for the purpose of protecting against price escalation.

2.4.1.5 Fuel Costs. Fuel costs present risk to the portfolio insofar as fuel costs are a primary drivers of generation costs except for renewable resources like solar and wind. Even more important is the effect on market prices of rising fuel costs when they occur in a market such as PJM or MISO, in which market clearing prices are set by the marginal producer.

Natural gas-fueled plants are the marginal producers during the summer months in both the PJM and MISO regions. Coal-fueled plants are the marginal producers for the majority of hours in PJM and MISO. Fortunately for consumers, natural gas prices have been low and subdued over the past few years, resulting in lower marginal (and thereby futures) prices for electricity. Part of the natural gas equation is the development of natural gas fracking methods. Potential regulation of the process may change the price dynamic for natural gas, and thereby electricity within the region.

In September of 2010, EPA took the first step in regulating natural gas hydraulic fracturing ("fracking") by issuing a voluntary information request to fracking firms which requested disclosure of chemicals used in the fracking process.[16] Although compliance is voluntary, EPA expects to use any information provided in their ongoing effort to study fracking by publishing a comprehensive study by "late 2012."[17]

Generally, EPA has authority under the Safe Drinking Water Act ("SDWA") to protect underground drinking wells, however, the Energy Policy Act of 2005 specifically exempted "the underground injection of fluids or propping agents (other than diesel fuels) pursuant to hydraulic fracturing operation related to oil, gas, or geothermal production activities" from regulation.[18] The proposed "Fracturing Responsibility and Awareness of Chemicals Act of 2011" attempts to remove this exemption, but it is currently receiving Committee attention in the House of Representatives.[19]

Meanwhile, some states have attempted to limit the location of fracking operations through zoning regulations.[20] However, state regulation of the ability of fracking operations to use undisclosed chemicals is specifically preempted by the SDWA.[21] Therefore, permits to start and maintain fracking operations continue to be approved by state regulators.

If fracking operations continue without additional regulation that adds cost to fuel extraction, such operations would tend to put downward pressure on the price of electricity, by increasing the supply of natural gas.[22] Any stricter federal or state regulations will likely increase the price of electricity by adding costs to natural gas production. Although hydraulic fracturing operations are not a major source of natural gas supply in Illinois, the nation-wide regulation of those operations will likely affect the price for natural gas supply in Illinois. The IPA should monitor the regulatory approach to fracking and anticipate an increase in natural gas costs if the EPA or other states increase regulation of fracking operations.

Electricity market prices incorporate fuel price risk. Mitigation options outside of the proposed portfolio design would have limited utility as the portfolio design is geared towards mitigating general electricity price risk.

2.4.1.6 Weather Patterns. Weather patterns present risk to the portfolio because weather-related changes in demand and supply correlate with spot prices. Particular risks include the possibility of having to sell electricity contracted for at relatively high fixed prices at a time of low spot market prices, or in the opposite case, having to purchase extra volumes at high spot prices.

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[16] EPA, Letter to Fracking Industry (accessed May 10, 2011 at http://water.epa.gov/type/groundwater/uic/class2/hydraulicfracturing/upload/HFvoluntaryinformationrequest.pdf).

[17] See http://water.epa.gov/type/groundwater/uic/class2/hydraulicfracturing/index.cfm.

[18] Pub. L. 109-58, title III, Sec. 322, 119 Stat. 694 (Aug. 8, 2005).

[19] http://www.gpo.gov/fdsys/pkg/BILLS-111s1215is/pdf/BILLS-111s1215is.pdf.

[20] *Huntley & Huntley, Inc. v. Borough Council of Oakmont*, 964 A.2d 855, 865-69 (Pa. 2009).

[21] Hannah Wiseman, *Trade Secrets, Disclosure, and Dissent in a Fracturing Energy Revolution*, 111 Colum. L. Rev. Sidebar 1 (Jan. 27, 2011).

[22] There is some debate over the economics of fracking. Current production is less than originally expected and some argue that true economic fracking potential is much more limited than what is currently predicted.

Selling fixed-price electricity back into a low spot price market. Electricity consumption is highly correlated to weather (e.g. hot summer temperatures drive up summer cooling load). If mild summer weather were to reduce regional cooling loads, spot prices for electricity would drop. With mild weather effectively reducing demand for electricity, consumption would drop below projections based on average temperatures. Excess energy procured through block contracts would have to be sold back into the market, likely at a price lower than what was originally paid. The resulting financial losses would be applied against the portfolio.

Purchasing spot price electricity from a high spot market. If warm summer weather were to increase regional cooling loads, spot prices for electricity would rise. With warmer weather effectively increasing demand for electricity within the portfolio, consumption would increase above projections that were based on an assumption of marginally lower average temperatures. Excess energy would need to be procured from the spot market to meet portfolio requirements, likely at a price higher than what was paid for fixed price purchases executed through the standard procurement process. The resulting increased costs would be applied against the portfolio.

2.4.1.7 Transmission Costs. The Utilities operate in separate regional transmission organization ("RTO") markets: Ameren in MISO and ComEd in PJM. Risks associated with these markets are new transmission asset related costs, tariff rules, and the potential for cost sharing on super-regional transmission lines.

The IPA is limited in its ability to mitigate these growing risks outside of factoring them into cost modeling over the longer range horizon and seeking offsetting cost avoidance elsewhere within the Portfolio, for example, through investments in distributed resources. However, transmission cost allocation is a subject of federal regulation and any changes in transmission costs will likely be borne by all customers regardless of supplier.

Midwest ISO Proposal for Pre-Certification of Transmission Paths for Export Transactions. On September 22, 2010 MISO, filed proposed tariff revisions with FERC that provide an additional study option for firm "point-to-point" transmission service, to facilitate the export of generation from MISO to an external border.[23] According to MISO, the proposal was in response to stakeholder comments advocating enhanced ability to export excess generation from the MISO footprint in transactions that cross MISO's borders.[24] In MISO's view, making additional transmission services studies available to generators will promote the use of existing generation that might otherwise be mothballed or retired, because there would be less delay and uncertainty for exporting customers in negotiating multiple, individual transactions.[25] Ameren Energy Marketing, which intervened in the FERC proceeding to ask for more detail from MISO, contended that development of a cross-border deliverability agreement, or a common/joint capacity market, would be necessary to better facilitate cross-border transactions.[26] Pointing to statements from MISO that lack of a common market mechanism interferes with the sale of MISO capacity into other markets, Ameren Energy Marketing argued that FERC should direct MISO to better align its proposed studies, including its deliverability study periods, with the capacity planning years in MISO and adjoining markets.[27]

FERC conditionally agreed to accept MISO's proposal, but agreed with Ameren Energy Marketing and others that more detail was needed in MISO's tariffs.[28] The FERC agreed that facilitating export transactions to the MISO border will provide benefits to market participants, but rejected Ameren Energy Marketing's notion of a joint market agreement between PJM and MISO if any changes to the existing Joint Operating Agreement between the two RTOs were needed.[29] MISO was further directed to adjust its proposed annual review to ensure that generators seeking to export will have an accurate assessment of the amount of capacity available on pre-certified paths, to avoid overselling transmission service.[30]

Changes in transmission pathways for excess generation will affect not only transmission planning, and supply/capacity prices, but could also affect generation investment in the MISO region.

[23] *In Re Midwest Independent Transmission System Operator, Inc.*, FERC Docket No. ER10-2869-000, Order Feb. 17, 2011 ("Export Transmission Order").

[24] Export Transmission Order at 2.

[25] *Id.* at 2-3.

[26] *Id.* at 4.

[27] *Id.* at 5.

[28] *Id.* at 10.

[29] *Id.* at 11.

[30] *Id.*

While this proposal does not impact any existing variable directly, it could impact the prices of generation across the seam that exists between PJM and MISO, the economics of cross-border prices, and possibly prices within the RTOs. These effects could affect the prices that the IPA pays for power and energy. The effects will need to be monitored closely, as the true impact is likely directly related to the criteria developed for final implementation (e.g. whether a joint capacity zone is created or how capacity portability will work).

Midwest Independent Transmission System Operator, Inc. Resource Adequacy Construct. Over the past several years MISO has undertaken a "resource adequacy planning" process to examine the ways in which it ensures that adequate electricity resources are available for use at all times on the MISO system. Beginning in 2009, MISO has used the threat of financial penalties on load serving entities ("LSEs") who do not demonstrate to MISO that they have procured adequate resources based on an annual Loss of Load Expectations ("LOLE") study.[31] The resulting resource adequacy requirement is expressed as a "Planning Reserve Margin" ("PRM") in excess of the forecasted system non-coincident peak. Each year LSEs submit an annual resource plan that specifies what planning resource credits ("PRCs") will be used to meet the resource adequacy requirement. Based on MISO's monthly compliance rules, this plan can be updated one month prior to the operating day.

In 2009, FERC examined MISO's long-term resource adequacy plan, and in February 2009 FERC required MISO to develop a permanent approach to address congestion that limits aggregate deliverability and to examine whether a locational capacity requirement would be needed to ensure reliability.[32] The FERC ordered MISO to evaluate a locational capacity approach to addressing the deliverability issue, like those used in PJM, ISO New England and the California Independent System Operator.[33] Over the course of 2009, MISO met with stakeholders, who could not agree on the best approach to resolving the issue, and who, in MISO's opinion, did not offer much support for adopting the local capacity requirements used by other regional transmission operators.[34] MISO concluded that its existing tariffs were sufficient to address any congestion issues that might limit deliverability, and filed its conclusions before FERC. MISO also concluded that its system-wide planning reserve margin approach was sufficient to maintain reliability, based on MISO's loss of load expectations ("LOLE") studies.[35] Several parties intervened to contest MISO's conclusions. Among them was Ameren Services Company on behalf of the Ameren companies, which requested a substantive explanation and information on how MISO would provide sufficient data concerning congestion and import-constrained zones within the MISO footprint to enable market participants to provide solutions to aggregate deliverability problems.[36] MISO responded to such concerns by noting its planning process shows no upcoming issues related to the delivery of planning resources through 2018.[37] MISO further maintained that locational capacity requirements are not appropriate for the MISO area and would only add uncertainty while not improving reliability.[38] Any approach based on locational capacity, MISO argued, would be inconsistent with the "energy-only resource adequacy" construct MISO had previously adopted.[39]

FERC, however, concluded differently. MISO's compliance filing was rejected, because it did not identify a permanent approach to address congestion that limits deliverability in the resource adequacy markets.[40] FERC had expected MISO to use as a starting point the market mechanisms utilized by other RTOs – mechanisms such as locational pricing and locational market rules that provide incentives for market participants to obtain sufficient local resources to secure reliability.[41] The FERC determined that the existing LOLE and other study processes were not sufficient, and that for MISO and its stakeholders to fail to develop market mechanisms that address locational resource adequacy simply because "market participants desire a

[31] "Midwest ISO's Resource Adequacy Construct: An Evaluation of Market Design Elements," The Brattle Group, January 19, 2010.

[32] *In Re Midwest Independent Transmission System Operator, Inc*., Order on Compliance Filing ("Compliance Filing Order") FERC Docket ER08-394-024, June 8, 2010.

[33] Compliance Filing Order at 2.

[34] *Id.* at 3.

[35] *Id.*

[36] *Id.* at 4.

[37] *Id.* at 6.

[38] *Id.*

[39] *Id.*

[40] *Id.* at 7.

[41] *Id.*, noting that if MISO had believed its existing tariffs were sufficient to address any congestion issues, MISO could have – and should have – requested rehearing of that Commission order.

more convenient auction tool" than approaches used by other RTOs would sacrifice long-term locational reliability.[42] The FERC directed MISO to develop a plan that allows auction planning credits and locational market mechanisms, which would coexist in MISO's resource adequacy plan.[43]

As a result, over the past two years, MISO has been working to develop a plan along the lines directed by the FERC. The key components of MISO's approach are:

- Establishing system planning reserve requirements with zonal definitions based on planning studies;
- Using annual coincident peak demand forecasts from LSEs and (for retail choice states) electric distribution companies (EDC);
- Qualifying planning resources on a one-year forward basis; and
- Recognizing those resources approved by state integrated resource planning resources.

Energy efficiency and price responsive demand are being pursued in parallel with this planning effort, and will be included as planning resources when measurement and verification details have been determined.[44]

MISO proposes to establish seven local resource zones, with capacity requirements met with planning resources located within each zone or from outside the zone if transmission capacity is sufficient. Within each zone, local clearing requirements will established, along with capacity import and export limits, which will be established for each zone. LSEs will meet those requirements through participation in the annual Planning Resource Auction." The auction would be conducted as a single round, sealed bid auction, similar to that used by MISO for the MISO Day Ahead market.

MISO has integrated demand resources that operate as supplemental capacity on peak days into its planning. Demand resources, demand response resources and behind-the-meter generation contributed more than 8500 MW of unforced capacity during the peak month of June 2008 – making up 6.8% of all planning resources.[45] This would put MISO on a par with other RTOs who integrate demand response and energy efficiency into their supply or capacity markets. For example, for the 2012/2013 planning year, demand response and energy efficiency represented 5.9% of the total committed resources in PJM and 7.8% in ISO New England; the share of capacity from the demand side in NY ISO was 6.4% for the summer of 2009.

If MISO does establish a working capacity market, the resulting financial incentives to invest in demand response resources should create new products and increasing amounts of demand response activities aimed at lowering peak demand.

Midwest ISO Proposal for Dispatchable Intermittent Resources. In February, 2011, FERC approved a proposal by MISO to create a new category of resources, Dispatchable Intermittent Resources ("DIRs"), which would be treated similarly to other generation resources in MISO's real-time energy market.[46] The goal of MISO's proposal was to utilize the capability of some variable resources to respond to instructions to reduce output to address market and operational inefficiencies caused by the manual curtailment of intermittent resources, in turn increasing the participation of variable resources in the MISO markets.[47] The proposal would take effect after a two-year transition period, at which time qualified resources would be able to set market prices and receive real-time credits based upon the maximum megawatt levels the resources could provide for each five-minute interval in the real-time energy market.[48] FERC conditionally accepted MISO's proposal to improve market efficiency and reliability.[49] However, FERC limited the scope of the

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[42] Compliance Filing Order at 8.

[43] *Id.*; FERC clarified in an order on April 27, 2011 that MISO should evaluate locational capacity approaches along with any other approaches, to address the aggregate deliverability issue in the MISO footprint.

[44] "Midwest ISO Resource Adequacy Proposal for 2013/2014 Planning Year," Supply Adequacy Working Group, February 17, 2011.

[45] Energy efficiency is not included in the supply side for MISO, as it has been in forward capacity markets such as PJM and ISO New England. Brattle Report at 27. Both systems count energy efficiency as a supply resource for two reasons – first, doing so allows third-party providers of energy efficiency services to capture the peak-reducing value of their projects. Second, it ensures the peak-reducing value of the measure is recognized in a timely manner, rather than waiting to observe the effects on load, then incorporating the effects in the following forward auction for delivery three years later. There is no threat of such lags in MISO, where the resource adequacy requirement is months, not years, ahead.

[46] *In Re Midwest Independent Transmission System Operator, Inc.*, FERC Docket No. ER11-1991-000, Order Feb. 28, 2011 ("Dispatchable Intermittent Resources Order").

[47] Dispatchable Intermittent Resources Order at 2.

[48] *Id.* at 3, 5.

[49] *Id.* at 5.

proposal to wind resources only and further limited the ability of resources to switch between status as Intermittent Resources or DIRs.[50] Resources qualified as DIRs will be subject to excessive/deficient energy deployment charges since these charges would provide an incentive for updating the forecasted loads as accurately and as often as possible.[51] Finally, among other tariff changes, MISO was directed to file at FERC a study of whether DIRs should be eligible to provide supplemental spinning and/or regulating reserves.[52]

This proposal could encourage investment in renewable resources. It will need to be monitored closely, as its true value is directly related to the criteria developed for final implementation.

Issuance of Final Rule on Demand Response (DR) Compensation. In response to Congressional directives to "encourage DR and to remove barriers to the participation of DR in energy markets,"[53] FERC has issued new rules regarding compensation for demand response resources to "ensure that rates are just and reasonable in the organized wholesale energy markets."[54] On March 18, 2010 FERC proposed a rule that would require Independent System Operators ("ISOs") and Regional Transmission Organizations ("RTOs") to pay the "Locational Marginal Price" ("LMP") for particular types of energy that respond to demand changes.[55] After a year-long comment period, FERC issued the final DR rule on March 15, 2011.[56] The rule is intended to improve the functioning and competitiveness of the organized wholesale energy market, either through a reduction in customer demand (as demand responds to high prices for peak loads) or by providing demand response as a resource in organized wholesale energy markets, to balance supply and demand.[57]

Under the new rules, ISOs and RTOs have to pay demand response resources the full LMP for energy that: (1) "has the capability to balance supply and demand as an alternative to a generation resource;" and (2) "is cost-effective as determined by the net benefits test."[58]

The net benefits test mandated by the second criterion for full LMP payment ensures that "the overall benefit of the reduced LMP that results from dispatching demand response resources exceeds the cost of dispatching and paying LMP to those resources."[59] In connection with this new net benefits test, FERC directs RTOs and ISOs to "develop a mechanism as an approximation to determine a price level at which the dispatch of demand response resources will be cost-effective."[60] While RTOs and ISOs are permitted to show how their existing practices are consistent with the net benefits criterion, any mechanism must ensure that "the monthly threshold price corresponding to the point along the supply stack beyond which the overall benefit from the reduced LMP resulting from dispatching demand response resources exceeds the cost of dispatching and paying LMP to those resources."[61]

All tariff changes required to implement the new rule must be made on or before July 22, 2011.[62] Each RTO's or ISO's compliance filing will become effective after FERC issues an order addressing that filing.[63] Each RTO and ISO is required to file a study with FERC on or before September 21, 2012 "examining the requirements for and impacts of implementing a dynamic approach which incorporates the billing unit effect in the dispatch algorithm to determine when paying demand response resources at the LMP results in net benefits to customers in both the day-ahead and real-time energy markets."[64]

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[50] *Id.*

[51] *Id.* at 32.

[52] *Id.* at 42.

[53] Energy Policy Act of 2005 § 1252(f).

[54] DR Rule at 3.

[55] *Demand Response Compensation in Organized Wholesale Energy Markets*, Notice of Proposed Rulemaking, FERC Stat. & Regs. ¶ 32,656 (2010) ("NOPR").

[56] *Demand Response Compensation in Organized Wholesale Energy Markets*, Order No. 745, FERC Stats. & Regs. ¶ 31,322 (2011) ("DR Rule").

[57] *Id.* at 7.

[58] *Id.* at 2.

[59] *Id.* at 3-4.

[60] *Id.* at 4.

[61] *Id.*

[62] *Id.* at 5.

[63] *Id.*

[64] *Id.* at 6.

FERC anticipates that the DR Rule will provide more just and reasonable energy prices, because RTOs and ISOs can better balance supply and demand by reducing dispatch of higher-priced resources that satisfy loads for which customers can curtail demand.[65] If more demand is responsive to higher market prices, the greater competition to provide those loads is predicted to place "downward pressure … on generator bidding strategies by increasing the risk to a supplier that it will not be dispatched if it bids a price that is too high."[66] Finally, FERC's rule should support system reliability and address adequacy and management challenges by providing a quick balancing of the electricity grid.[67]

Before adoption of this new rule, each RTO and ISO was free to develop its own compensation methodologies for resources participating in day-ahead and real-time energy markets.[68] As a result, the level of compensation for DR varies significantly among RTOs and ISOs.[69] This rule will likely require that PJM increase compensation, since its previous compensation scheme was for less than full LMP; MISO's level of compensation will likely stay the same. The overall price of electricity in PJM will likely rise, since PJM can no longer compensate these resources at previously lower prices. Although the price of demand response resources will likely also increase in the PJM market, the systemic benefits identified by FERC (better balance of supply and demand, reduction of high-priced loads, greater competition, greater reliability) may offset those increases. It is possible that the increased reliability, reduction in demand of high-priced loads, and greater competition in the wholesale energy market may place sufficient downward pressure on prices in the PJM and MISO markets to offset any increase in compensation required by the DR Rule. The IPA should continue to monitor the effect on prices for wholesale electricity in both interconnections, anticipating a slight increase in the PJM interconnection's price for demand response resources.

2.4.1.8 Market Conditions. Market conditions generally relate to the drivers of market prices, customer usage, and customer switching levels. These variables are included in the statistical modeling conducted by the IPA relative to the portfolio design. The current supply mix in Illinois has remained largely unchanged over the last decade, with the majority of the state's electricity generated by nuclear and coal fired plants located within the state. Coal is the marginal fuel for most hours in the year, with wind depressing prices during some nighttime hours and natural gas setting prices during system peaks.

Greenhouse Gas Regulation. On April 2, 2007, the United States Supreme Court ("Supreme Court") held that greenhouse gases ("GHGs") are "air pollutants" under the Clean Air Act ("CAA"), and that the Environmental Protection Agency ("EPA") could not refuse to regulate these gases[70] As a result, the EPA was directed to decide whether GHGs from motor vehicles "cause, or contribute to, air pollution which may reasonably be anticipated to endanger public health or welfare."[71] Subsequently, on December 15, 2009, the EPA published an endangerment finding, concluding that motor vehicle emissions of GHGs endanger public health and welfare.[72] In particular, EPA found that emissions of carbon dioxide (CO2), methane (CH4), nitrous oxide (N2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6) may reasonably be anticipated to endanger public health and welfare.[73] While lawsuits challenging the endangerment finding were filed by industry groups, EPA has moved forward with regulating GHGs for mobile and stationary sources of the six GHGs identified above. Stationary sources include "power plants, chemical plants, oil refineries, manufacturing facilities, and other industrial facilities" that are non-moving, fixed-site emitters of pollutants subject to CAA regulation.[74]

Under the CAA, the Prevention of Significant Deterioration Program ("PSD") applies to new and modified major stationary sources that potentially emit 100 to 250 tons of GHGs per year.[75] PSD regulations require

[65] *Id.* at 8.

[66] *Id.*

[67] *Id.* at 9 (citing an ERCOT incident on February 26, 2008 when a drop in power supplied by wind generators was balanced by 1200 MW of Load acting as Resource, see Oak Ridge Nat'l Lab. Nat'l Renewable Energy Lab., Tech. Rep. NREL/TP-500-43373 (Jul. 2008)).

[68] *Id.* at 11.

[69] *Id.* at 11-12 (noting that the MISO demand response program pays LMP and the PJM demand response program pays LMP minus generation and transmission portions of the retail rate).

[70] *Massachusetts v. Envtl Prot. Agency*, 549 US. 497 (2007).

[71] *Id.* (citing CAA § 202(a)(1)).

[72] 74 Fed. Reg. 66,495 (Dec. 15, 2009).

[73] *Id.*

[74] http://www.epa.gov/apti/course422/ap3b.html (accessed May 17, 2011).

[75] Clean Air Act § 165.

new major stationary sources to undertake a Best Available Control Technology ("BACT") analysis "for each regulated [New Source Review] ("NSR") pollutant that it would have the potential to emit in significant amounts."[76] A "regulated NSR pollutant" is "any pollutant that … is subject to regulation under the Act [with immaterial exceptions]."[77] EPA believes that the combination of these provisions means that the six GHGs became PSD-regulated pollutants on January 2, 2011.[78]

To avoid regulation of smaller sources of GHG emissions, where the costs could be so burdensome as to force them to cease operation, the EPA published a "Tailoring Rule" on June 3, 2010. That rule increased the threshold for regulation of GHG emissions from a band of 100 to 250 tons per year to a total output of 75,000 tons per year, expressed in the common metric of CO2 equivalents ("CO2e").[79] In addition, the rule establishes a multi-phase approach to GHG regulation under the PSD program. In Phase 1 (between January 2, 2011 and June 30, 2011), only new and modified sources[80] that would be subject to PSD permitting due to their emissions for pollutants other than GHGs would be subject to PSD requirements for GHGs (and then only if the source potentially emits 75,000 tons per year of CO2e).[81] In Phase 2 (between July 1, 2011 to June 30, 2013), new sources that potentially emit 100,000 tons per year of CO2e and modified sources that potentially emit 100,000 tons per year of CO2e with modification-induced emission increases of 75,000 tons per year of CO2e will require PSD permits for GHG emissions.[82] In Phase 3 (from July 1, 2013 forward) EPA will undertake another rulemaking beginning in 2011 and concluding by July 1, 2012 to phase-in smaller sources of GHG emissions, but will not require permitting for sources that emit less than 50,000 tons per year of CO2e.[83]

On November 10, 2010, EPA issued guidance on the PSD process for new sources, either those undertaking new construction or sufficiently modifying their facilities to become new sources under the CAA.[84] This EPA guidance explains the BACT analysis that facilities requiring PSD permits must undertake with respect to GHGs. EPA does not establish a presumptive BACT nor does it offer a new approach for selecting BACT.[85] EPA does, however, focus on the energy efficiency of technologies to determine which approach constitutes BACT for the particular source, noting that while carbon capture and storage is a promising technology that merits consideration, it will unlikely constitute BACT due to technical feasibility and cost.[86] Having well-defined BACT specifications can help sources in affected categories by providing regulatory certainty regarding installation of technology to comply with federal and state pollution control laws. However, industry commentators note that for the initial PSD permits, compliance with the new GHG related requirements are "likely to be a time-consuming, complicated and expensive process for regulated entities."[87] In addition to new sources subject to PSD requirements, existing sources with Title V permits under the CAA will be required to address GHGs as part of their continuing Title V permit obligations (such as renewals) under the timetable set forth in the Tailoring Rule.[88]

In determining BACT, the EPA has deferred for three years its decision on whether it will issue a supplemental rule exploring separate accounting rules for different types of feedstock for sources of biogenic

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[76] 40 C.F.R. § 52.21(J)(2).

[77] 40 C.F.R. § 52.21(b)(50)(iv).

[78] 75 Fed. Reg. 31,522-23.

[79] 75 Fed. Reg. 31,513 (June 3, 2010).

[80] Under the CAA, "new" and "modified" sources are those stationary sources that begin construction of their source or sufficiently modify their source after the date of promulgation of New Source Performance Standards for that particular source category. 42 U.S.C. § 7411.

[81] *Id.* at 31,516.

[82] *Id.*

[83] *Id.* at 31,575; 31,578.

[84] *PSD and Title V Permitting Guidance for Greenhouse Gases* (Nov. 2010), EPA-HQ-OAR-2010-0841-0001, (accessed May 10, 2011 at http://www.epa.gov/region4/air/permits/GHG%20Permitting%20Guidance%20-%2011-10-10%20public.pdf) ("GHG Guidance").

[85] *Id.* at 1.

[86] *Id.*

[87] Robert Wyman, *EPA's PSD and Title V Permitting Guidance for Greenhouse Gases: Overview and Analysis*, Practising Law Institute Order No. 29209 (Feb. 9, 2011).

[88] GHG Guidance at 2, 3 n.6 (explaining that EPA does not intend to required PSD permits issued prior to January 2, 2011 to address GHGs, regardless of their effective date); 75 Fed. Reg. 17,004.

GHG emissions.[89] Since add-on controls to reduce GHG-emissions are not as well-advanced for as for most combustion-derived pollutants, energy-efficient measures will serve as the "foundation for a BACT analysis for GHGs."[90] In addition, EPA believes that "performance benchmarking" should be used to compare a unit's energy performance to determine whether additional gains in energy efficiency are achievable.[91] Significantly, the EPA recommends using "output-based metrics" instead of input-based metrics in Step 3 of BACT analyses to more fully consider thermal efficiency and power demand in ranking control options based on total CO2e instead of total mass.[92] In Step 4 of BACT analyses, permitting authorities will have greater discretion to consider a wide range of various direct and indirect economic, energy, and environmental impacts of the control options.[93] Finally, in Step 5 of the BACT analyses, EPA recommends a focus on metrics relying on longer-term averages (e.g., 365 rolling average) to reflect the cumulative impact of GHGs in the environment.[94]

Sources not subject to PSD, such as pollution sources that were constructed before the new source performance standards ("NSPS") for their source category were promulgated or sources that have not been sufficiently modified, have distinct requirements. For those sources, the GHG BACT must be incorporated into a Title V permit if the source: (1) potentially emits GHGs that equal or exceed 100,000 tons per year on a CO2e basis; and (2) potentially emits GHGs in amounts that equal or exceed 100 tons per year of GHGs on a mass basis.[95]

EPA's GHG regulations would likely increase the cost of generating for fossil-fueled electricity and therefore increase the market price of electricity, particularly in hours when fossil-fueled power plants are on the margin. To provide greater guidance for the largest GHG emitters, and as a result of a lawsuit by citizens groups and states, EPA entered a settlement agreement binding it to rulemakings regarding electric generating units at fossil fuel-fired power plants and refineries.[96] This settlement requires EPA to propose regulations for new source performance standards and emission guidelines by July 26, 2011 (to be finalized by May 26, 2012) for natural gas, oil, and coal-fired electric generating units ("EGUs").[97] For refineries, EPA has agreed to issue proposed regulations establishing NSPS and emission guidelines for existing refineries by December 10, 2011 (to be finalized by November 10, 2012).[98] Despite these proposed rulemakings, states have the ability to apply less stringent standards or longer compliance schedule if they demonstrate that the federal requirements are "unreasonably cost-prohibitive, physically impossible, or that there are other factors that reasonably preclude meeting the guidelines."[99]

Regardless of what happens with these Congressional proposals, EPA's proposed GHG regulations will likely increase the cost of fossil-fueled electricity generation. Even the most far-reaching proposals limiting EPA's authority to regulate the emission of GHGs preserve EPA's authority to propose fuel-economy standards jointly with the DOT. In the meantime, by imposing new requirements on the largest emitters of GHGs, EPA's GHG rules require new and modified sources to immediately implement new control technologies to meet the BACT standards. Because such technologies are largely untested and relatively new, their selection and implementation will likely impose a large cost on GHG emitters. Even for existing sources of GHGs, EPA's rules will eventually require BACT for general operating permits. Additionally, the sources subject to EPA's settlement regarding NSPS and emission limitations for EGUs and refineries are some of the largest providers of electricity supply. Requiring new equipment or control methods for their GHG emissions will raise the cost of supply from these generators and, thus, will likely increase the unit-cost of electricity.

[89] Deferral for CO2 Emissions From Bioenergy and Other Biogenic Sources Under the Prevention of Significant Deterioration (PSD) and Title V Programs, 76 Fed. Reg. 43490 (July 20, 2011).

[90] GHG Guidance at 30-31 (explaining that EPA does not intend to required PSD permits issued prior to January 2, 2011 to address GHGs, regardless of their effective date); 75 Fed. Reg. 17,004.

[91] *Id.* at 22-23, App. J.

[92] *Id.* at 39.

[93] *Id.* at 44-45.

[94] *Id.* at 46-47.

[95] *Id.* at 52-53.

[96] EPA, Settlement Agreement to Address Greenhouse Gas Emissions From Electric Generating Units and Refineries, Fact Sheet (accessed May 10, 2011 at http://www.epa.gov/airquality/pdfs/settlementfactsheet.pdf).

[97] *Id.* at 1.

[98] *Id.* at 2.

[99] *Id.*

Because the GHG Rules are being applied to energy sources that were not the direct target of the fuel-economy standards, existing regulatory impact analyses do not address the costs, burdens, and timetables required of power plants subject to the rules.

Mercury Regulation. On March 29, 2005, EPA promulgated a final rule concluding that it was neither appropriate nor necessary to regulate coal and oil fired electrical generating units ("EGUs") under Section 112 of the Clean Air Act ("CAA").[100] Subsequently, on May 18, 2005, EPA issued the Clean Air Mercury Rule ("CAMR") establishing standards of performance for emissions of mercury from new and existing coal-fired EGUs under Section 111 of the CAA.[101] Ensuing litigation has since vacated the CAMR on the grounds that EPA's assumption that there would be no Section 112 regulation of EGUs was incorrect, rendering the Section 111 standards null and void.[102] Environmental and public health organizations thus filed suit against the EPA, alleging that it failed to perform a nondiscretionary duty when it failed to promulgate standards for hazardous air pollutants ("HAPs") emitted from coal and oil fired EGUs pursuant to Section 304(a)(2) of the CAA.[103] The consent decree resolving that litigation requires EPA to propose rules regarding emission standards for coal and oil fired EGUs, to be finalized November 2011.[104]

On May 3, 2011, EPA proposed a *National Emission Standard for HAPs from Coal and Oil Fired EGUs and Standards of Performance for Fossil-Fuel-Fired EGUs* ("National Emission Standard").[105] Because mercury is shown to deposit in higher quantities close to emissions sources, EPA determined that depositions near EGUs constituted a threat to public health and welfare.[106] Moreover, EPA has determined that "currently available control technologies for Hg [Mercury], acid gases, and non-Hg metal HAP shows that significant reductions in these pollutants can be achieved from EGUs."[107] In EPA's estimation, application of available Hg controls in 2016 would reduce Hg emissions by seventy-nine percent (79%) for EGUs.[108]

The National Emission Standard proposes to require approximately 1,200 existing "coal-fired" and 150 existing "oil-fired" EGUs at about 525 power plants to conform to more stringent emission limitations for mercury and other toxic metals.[109] Specifically, the National Emission Standard establishes numerical emission limits for mercury, PM (a surrogate for toxic non-mercury metals) and HCl (a surrogate for toxic acid gases).[110] Compliance with these new emission limits may require installation of dry scrubbers, dry sorbent injection systems, activated carbon injection systems, and baghouses.[111] The proposed rule provides facilities with up to four (4) years to come into compliance.[112] By 2016, EPA estimates that the National Emission Standard will annually cost $10.9 billion.[113]

By 2015, EPA estimates that the annual incremental cost of compliance with the National Emission Standard will be $10.9 billion, or a 3.5% increase in costs to generate, transmit, and distribute electricity to end-use consumers.[114] At the same time, EPA estimates that about 9.9 GW of coal-fired capacity will become uneconomic to maintain due to the standard, reducing total coal-fired capacity by roughly 3%.[115] Coal

[100] 70 Fed. Reg. 15,994; EGUs are defined as fossil fuel-fired combustion units of more than 25 megawatts electric (MWe) that serve a generator that produces electricity for sale. A unit that cogenerates steam and electricity and supplies more than one-third of its potential electric output capacity and more than 25 MWe output to any utility power distribution system for sale is also an electric utility steam generating unit.

[101] 70 Fed. Reg. 28,606.

[102] *New Jersey v. Envt'l Prot. Agency*, 517 F.3d 574 (D.C. Cir. 2008).

[103] 76 Fed. Reg. 24,986.

[104] *Id.*

[105] *Id.* at 24,976.

[106] *Id.* at 25,013.

[107] *Id.* at 25,014.

[108] *Id.* at 25,015.

[109] EPA, Proposed Mercury and Air Toxics Standards, Fact Sheet at 2 (accessed May 17, 2011 at http://www.epa.gov/airquality/powerplanttoxics/pdfs/proposalfactsheet.pdf).

[110] *Id.*

[111] *Id.*

[112] *Id.* at 3.

[113] *Id.* at 4.

[114] EPA, *Regulatory Impact Analysis of Proposed Toxics Rule* at 401 (accessed May 31, 2011 at http://www.epa.gov/ttnecas1/ToxicsRuleRIA.pdf).

[115] *Id.* at 405.

production for electricity generation is expected to decline modestly as a result, however, demand for bituminous coals is expected to increase slightly.[116] Thus, EPA predicts that by 2015, the average retail electricity price will increase by 3.7%, falling to a 2.6% increase by 2020.[117] Comments on the proposed standard will be accepted until July 5, 2011, the final rule will be promulgated in the months thereafter with no specific deadline imposed by law. The IPA will continue to monitor the rulemaking for its potential effects on electricity prices.

Carbon Capture and Sequestration Regulation. On July 25, 2008, EPA proposed a Carbon Dioxide Injection and Geologic Sequestration Rule addressing the injection of GHGs into the ground.[118] The proposed rule noted that the Safe Drinking Water Act ("SDWA") did not provide EPA with the authority to develop regulations for all areas related to Carbon Sequestration, but it does provide authority to the extent necessary to protect underground drinking water wells.[119] In December of 2010, the EPA Administrator promulgated a final rule titled *Federal Requirements Under the Underground Injection Control Program for Carbon Dioxide Geological Sequestration Wells* ("UIC Rule").[120]

The UIC Rule establishes new federal requirements for the underground injection of carbon dioxide for the purpose of long-term underground storage.[121] To address the "unique nature" of CO2 injection with regard to its relative buoyancy, corrosivity, impurities, and mobility, the UIC Rule applies to operators of wells used to inject CO2 into the subsurface for purposes of long-term storage.[122] The UIC Rule thus requires owners, in addition to complying with existing UIC rules, to:

- Perform geologic site characterizations;
- Construct and operate wells with injectate-compatible[123] materials and automatic shutoff systems;
- Develop, implement, and update plan to manage sequestration projects;
- Periodically monitor operational data to verify that CO2 is moving as predicted;
- Test the mechanical integrity of the injection well;
- Extend monitoring to track the location of the injected CO2 until it can be demonstrated that drinking wells are no longer endangered; and
- Ensure funds will be available for corrective action, well plugging, site care, closure, and emergency response.[124]

To distinguish these new requirements from the state and federal permit applications for differing well classes, the UIC Rule creates a new class of wells under the SDWA (Class VI Wells) to promote transparency and national consistency in permitting.[125]

After promulgation of this final rule, state permitting authorities must apply to EPA for "primacy approval" under Section 1422 of the SDWA, which allows states to issue permits enforceable by courts.[126] States have nine months following promulgation to apply for primacy approval. If states do not apply or if states submit

[116] *Id.* at 408.

[117] *Id.* at 410.

[118] 73 Fed. Reg. 43,491.

[119] *Id.* at 43,493.

[120] 75 Fed. Reg. 77,230.

[121] EPA, *Underground Injection Control (UIC) Program Requirements for Geologic Sequestration of Carbon Dioxide Final Rule*, Fact Sheet at 1 (accessed May 10, 2011 at http://water.epa.gov/type/groundwater/uic/class6/upload/uicprogramrequirementsforGSofco2factsheet.pdf).

[122] *Id.* at 2.

[123] "Injectate-compatible materials" are construction materials that can withstand fluids with which those materials may be expected to come into contact and must meet or exceed standards developed for such materials by the American Petroleum Institute, ASTM International, or comparable standards. 40 C.F.R. § 146.86.

[124] *Id.*

[125] *Id.*

[126] *Id.* At this time, US EPA Region V has no listing of any states that have applied for permits; application are not due until August, 2011.

inadequate applications, then EPA will impose a "Federal UIC Class VI program."[127] In the meantime, states with existing Section 1422 primacy programs may issue permits under Class I or Class V well status.[128]

EPA estimates the total cost of implementation of the final rule to be between $31 and $38 million, representing approximately three percent (3%) of the total cost of carbon capture and storage.[129] Because of new requirements that specially account for CO2's unique properties, the UIC Rule will likely increase the cost of carbon storage and sequestration. Increasing the cost of carbon sequestration will directly raise the price for electricity sources using geological sequestration. Additionally, the UIC Rule will likely indirectly increase the price of electricity for consumers by increasing the price of coal generated electricity. However, to the extent that carbon sequestration could be considered BACT, and to the extent it proves cheaper than existing BACT options for sources subject to EPA's GHG Rules, the UIC Rule may slightly decrease the cost of compliance with GHG Rules.

While carbon capture, storage, and sequestration is in the initial stages of development, Illinois' legislative actions suggest a significant interest in using these methods to decrease emissions associated with coal-fired electricity generation. The IPA will monitor whether Illinois applies for primacy for its Class VI well permits, and whether the EPA approves or denies such primacy, to determine the specific requirements imposed on Class VI well owners and operators.

2.4.1.9 Alternatives for those portfolio measures that are identified as having significant price risk. While no analysis can cover every possible risk, the above analysis provides a reasonable representation of the significant risks associated with the June 2012 – May 2017 horizon. The Plan provides reasonable protection for customers from likely risk factors. As a result, given the guidance provided under the PUA, the IPA does not recommend an alternative to its recommended portfolio.

3.0 Procurement Design

The IPA is charged with developing a plan that mitigates risk while ensuring low stable prices for consumers. Taking into account the risks noted above, the IPA has designed a procurement plan to address risk and price issues for energy, capacity, renewable energy, and transmission resources.

3.1 Energy Resources. The IPA relies on Load Forecasts from ComEd and Ameren as the best estimates for future consumption factored for the largely unknown variable of retail switching. Since Utility data projections are updated annually, the IPA readjusts load projections to account for the current view on retail switching and other factors affecting load size and shape. Given the increase in residential switching in the past year, the IPA seeks updated forecasts from the Utilities in early November 2011 so as to improve the accuracy of purchase quantities resulting from the plan. Such forecasts were submitted to the Commission and to the IPA.

The ultimate goal of the Load Forecast is not to identify the combined load of all customers of the Utility. Rather, the 5-year hourly load forecast identifies load projections for "Eligible Retail Customers." Eligible Retail Customers include residential and small commercial customers entitled to purchase electricity from the Utility under fixed-price bundled service tariffs. The Utilities apply statistically adjusted end use models as the basis of its load forecasting process. After adjusting consumption data weather, seasonal variables, and economic conditions, detailed core consumption models are developed.

The econometric models produce monthly sales forecasts for primary customer classes. Those base monthly forecasts are normalized for primary load variables (weather, economic growth, population, etc.) and combined with the hourly models to obtain on-peak and off-peak quantities for each month and each delivery service class.

The statistical models are measured for accuracy against past period consumption volumes for each customer class. Comparisons between predicted and actual consumption volumes are highly correlated and are the best models available for forecasting loads for the eligible retail customers.

[127] *Id.* at 3.

[128] *Id.*

[129] *Id.*

Forecasted portfolio volumes are generated by altering model variables within expected ranges and examining model outputs. Resulting High, Expected, and Low volume scenarios are generated.

TABLE D: OVERVIEW OF KEY ENERGY RESOURCE ISSUES

Key Energy Resource Issues	
Volume	Price
▪ The IPA portfolio is expected to decline over time as consumers migrate to alternative supply options. ▪ Use of alternative supply options will likely increase as long as the IPA prices remains above the current market price for power. ▪ A portion of future IPA portfolio needs will be met through existing standard supply contracts; those volumes and delivery schedules are fixed. ▪ A portion of future IPA portfolio needs will be met through existing Long-Term Renewable Energy contracts; volumes and delivery are variable. ▪ **Securing excess supply can lead to losses through forced sell-back of volumes to the market; securing insufficient supply can lead to higher prices through forced spot-market purchases to meet actual use.**	▪ Underlying commodity costs face upward pressure due to inflation and gradual increase in economic activity. ▪ Generators anticipate elevated operating costs resulting from compliance with USEPA transport and Mercury rules. ▪ Owners of generation units within the region that cannot afford or finance upgrades to their existing coal-fueled resources may close - driving up clearing prices. ▪ A portion of future IPA portfolio needs will be met through existing Long-Term Renewable Energy contracts; costs escalate 2% per year over 20 years. ▪ **Securing excess future supply today can lead to higher than necessary costs if future prices decrease; securing less future supply today can lead to higher prices if future prices rise.**

TABLE E: OVERVIEW OF PRIMARY PLAN INCLUSIONS FOR ENERGY RESOURCES

Primary Energy Resource Measures	
Volume	Price
▪ Utilize the base (median) projection volumes for both Utilities as planning volumes	▪ Maintain procurement selection on the basis of price for standard products.

3.1.1 Background. The IPA maintains that a medium-term laddered approach to procurement for energy and capacity resources provides a high level of cost stability for consumers while still leaving room for some larger market trends – namely consumer migration from the IPA portfolio and the regulatory climate for fossil fuel power generators - to be better identified and assessed. The IPA proposes to continue the practice approved by the Commission in the 2009, 2010 and 2011 Procurement Plans of scheduling procurements of wholesale energy resources relatively evenly over three-year periods. While liquidity indicators for the 24 to 36 month horizons within wholesale energy markets have diminished somewhat, bidding activity in the Spring 2011 procurement cycle for contracts in that cycle's 24-36 month range indicates an adequate level of level of competition and bidder interest.

As prescribed in the 2009, 2010, and 2011 cycles, projections of annual procurement distributions ranging between 20% and 40% continue to indicate a sufficient mitigation of price risk for consumers. Because future market conditions cannot be known, the IPA proposes to employ a portfolio distribution schedule that allows between 20% and 40% of projected loads to be procured in each of the three years prior to the delivery month. Within this range, IPA proposes that the following three-year laddered procurement strategy has a high probability of yielding low risk and stable prices:

- 35% of projected energy needs procured two years in advance of the year of delivery.
- 35% of projected energy needs procured one year in advance of delivery.
- 30% of projected energy needs procured in the year in which power is to be delivered.

3.1.2 Evaluation. The options for electric energy products fall into two general categories: fixed price and variable price products. Fixed price products allow the purchase of known volumes of electricity to be delivered at some time in the future at a set price. Forward purchases, futures contracts, swaps, and options are examples of fixed price products. Fixed price products offer price certainty, but may turn out to be relatively costly if the market price drops prior to delivery, or if too much power is purchased and the excess must be sold back to the market at a loss.

Variable price products allow the purchase of electricity at prices set by supply and demand for electricity at the time of consumption. Locational marginal prices ("LMP") provided through RTOs are the basis of variable price products in organized wholesale markets. Variable price products offer the ability to buy only the amount of electricity needed at any moment, but may turn out to be relatively costly if high market prices exist at the time of usage.

In order to manage procurement for a variable population with uncertain loads in an unpredictable market, this Plan utilizes methods similar to those used by investors to manage market portfolio risks.

The Plan begins by first defining the portfolio and potential risks; then identifying measures that will mitigate those risks; and finally, measuring the relative effectiveness of the risk management measures. The risk profile of the IPA portfolio changes over time. Accordingly, the IPA will be making process improvements that allow for continuous monitoring and annual adjustments to the portfolio strategy as each Plan is developed.

The following are the premises upon which the IPA constructed its portfolio and risk management approach:

- **Physical and financial product parity:** A physical product is one in which the contract requires furnishing of a specified volume of electricity under the terms and conditions of the contract. A financial product is an agreement to guarantee the price for a specified volume of electricity. The IPA views prices for physical electricity products to be equivalent to financially based electricity products, insofar as suppliers of physical products price offers based on forward price curves determined in futures markets.
- **Three-year market liquidity horizon:** The IPA views existing forward markets as providing sufficient liquidity to assure price competition for up to three years. Trading volume in the periods greater than three years into the future are presently insufficient to assure that observed prices are available, reliable, and representative.
- **Historical price volatility as a guide to future volatility:** Past market performance with regard to price volatility, trending, and correlations is the basis of the assumptions incorporated into IPA modeling and evaluations.
- **Today's optimal portfolio distribution may not be optimal tomorrow.** The IPA seeks to identify price risk measured by the following three metrics:
    - **Metric A: Year-over-Year Price Variance** – the extent to which prices change from one year to the next.
    - **Metric B: Mark-to-Market Price Variance** – the extent to which prices agreed to in prior years vary from index prices in the current market.
    - **Metric C: Longitudinal Variance** – the extent to which prices in the latter years of a plan vary from current futures market prices.

A model portfolio for each Utility was developed and applied to each Utility's respective load projections to illustrate the trade-offs between risks and benefits associated with different procurement approaches and ratios of Forward and Index purchases. With efficient market prices, all portfolios should have the same expected value; however, price stability (measured as standard deviation) can vary. To evaluate the price stability of the different portfolios, volatility in the three metrics noted above (Year-over-Year Price Variance, Mark-to-Market Price Variance, and Longitudinal Variance) was measured and combined to generate a composite risk metric for use in the evaluation.
Existing (legacy) supply contracts dating from the 2007 rate relief agreements and subsequent procurement cycles will supply portions of the IPA portfolio into the period covered by this Plan. The IPA will be responsible for managing the procurement of that portion of the eligible-customer load not supplied by the legacy contracts.

The composite metric created is the square root of the average of (A) Year-over-Year Price Variance, (B) Mark-to-Market Price Variance, and (C) Longitudinal Variance:

Composite Metric = Square Root [(SDA^2 + SDB^2 + SDC^2)/3]
Where "SD" is Standard Deviation

A set of potential portfolios was evaluated with multiple model runs against the risk metric defined above. There are three main sections to the model, the first of which is the price section.

1. **Pricing.** The model uses monthly forward peak and off-peak New York Mercantile Exchange ("NYMEX") pricing through 2014 as of August 12, 2011. The IPA views NYMEX as an appropriate indicator of future

prices in the nearer term where market liquidity is sufficient to generate pricing competition. For periods after 2014, the monthly prices indicated on the NYMEX for those periods were escalated at 2% per year to account for market unknowns.
To test how each portfolio will perform under various market conditions, the forward price curves are assumed to vary over time. Prices for forward energy products are highly volatile, meaning that the price observed today for a product may be quite different than the price of that same product when observed at some point in the future.

These volatilities include changes in prices due to all factors, including fuel price movements. Market prices volatility was selected as the appropriate representative of market price risk as the Utilities do not own generation, and therefore, cannot control significant variables such as fuel expense.

Price movements in delivery periods beyond the first year of the forward curve were modeled to move proportionately to movements of the first year, but with somewhat lower volatility. The magnitude of these proportional movements is based on an historical analysis of how prices in years 2-6 of the forward curve moved relative to the magnitude in movements in the price of the first year of the forward curve. Consequently the forward prices in the analysis move together but with a muted effect as one goes out in time.

The process captures how the forward curve moves between annual procurement processes that are assumed to occur each March. The model then uses the same annual volatility estimates to estimate potential price movements from the March procurement date until the future delivery month. Once forward prices are estimated for each month as of the beginning of the month (i.e. the close of the forward product), monthly spot prices are then developed based on the historical volatility observed between the prices of the forward at the beginning of the month and the realized average spot price observed for each month. This process can be summarized as:

Spot Price = FPT + Pchg (T_T+1) + Pchg (March _ Delivery Month) + Pchg (Delivery Forward _ Spot)
Where FP means Forward Price and Pchg means Price Change

2. **Estimated Load Requirements.** As market prices are uncertain and will deviate from estimates, so too will the actual supply required by eligible customers deviate from even the best forecast. To capture this risk, the model starts with the base load estimates for eligible retail customers supplied by the Utilities on July 15, 2011, and then manipulates the loads based on both weather and non-weather (economy and retail switching) factors. The model assumes a triangular distribution for the loads based on the high/low load forecasts supplied by the Utilities.

   For each month for both peak and non-peak (wrap) periods, the model takes the included load for the scenario and estimates the net open requirements by subtracting (1) the load previously awarded through the auction process (2) the amount hedged through the swap arrangements.

3. **Average Cost to Serve.** The last major section of the model estimates the average cost to serve the included customers. For each iteration, the model sets a random load and price based on the distributions and correlations discussed above. The model then estimates the effective cost associated with the swap contracts (fixed price and quantity), the cost of any RFP purchases, transmission costs for ancillaries and capacity and finally, the cost associated with any spot purchases or sales to balance the procured quantities with those actually required. A blended portfolio price is calculated for each iteration and at the end of the run a distribution of potential outcomes is presented.

   A key factor in the analysis is the cost associated with load shape that results from customers using relatively more energy when prices are high and relatively less energy when prices are low. This relationship between expected prices and expected demand generally has the effect of raising the cost to serve load above the level of the straight average price during a delivery period. Since the procurement plan is using monthly block products that provide the same amount of energy every hour (i.e. not sculpted to match expected customer demand), the cost difference between supply provided by these block products and actual customer load profile is picked up through a price/load gross-up factor.

   A simple example of a price/load gross-up factor would be to assume a world with three hours where the customer loads were 10, 20 and 30 MW and the corresponding prices $50, $100, and $150/MWH. The average load is 20 MW and the average price is $100/MWH. However, since the price is highest when loads are highest, the actual average cost to serve the load is:

(10*50+20*100+30*150)/60 or $116.7/MWh

In this example, the load/price gross-up factor is 16.7% ($116.7/$100 – 1).

The level of gross-up variability, and how strongly those variations are correlated to movements in price and load, can play an important role in determining the desirability of one model portfolio versus another. If the correlation is very strong (i.e. when changes in monthly spot prices are high the change in the gross-up factors are also high), the analysis would show that risk-minimizing hedge ratios would be higher than if the correlation were weak or non-existent. A historical analysis of monthly gross-up factors, spot prices, and loads suggests that any relationships between gross-ups and price or between gross-ups and load may be relatively weak. While this result may not be intuitive, note that on a daily basis, the correlation between prices and gross-up factors is fairly strong, but when gross-ups and price/loads are measured over monthly intervals the strength of the relationship appears to diminish.

4. **Results.** The model was designed to help identify whether some portfolios may be superior to other portfolios when looking at specific risk metrics. For conceptual ease, the IPA separated portfolio characteristics into two categories:

   1) The composition of the portfolio (i.e. the what mix of products)
   2) The scale of the procurement (i.e. the volume purchased relative to the expected future load requirement)

   Several portfolio structures were tested in the model to help identify whether one was of relatively lower risk than the others when evaluated using the composite risk metric. The portfolio structures analyzed ranged from all requirements being purchased in the RFP just prior to the beginning of the delivery period to all requirements being purchased three years in advance (the extent of assumed market price liquidity). Each of these portfolios was scaled to provide 100% of the expected load requirement so that scale effects could be disassociated from composition effects.

   For the portfolio structure analysis, the IPA focused on the 2013 - 2014 period, the IPA chose this time period in order to get past legacy contracts including the swaps which tend to distort near term results in an attempt to illustrate the level of risk each portfolio would produce in a 'Steady State'.

   The lowest price risk scenario is achieved when the portfolio is procured relatively evenly over three years, the current period for which there is sufficient liquidity in wholesale energy markets. Procurement distributions ranging between 20% and 40% per procurement cycle were determined to be relatively comparable in their capacity to mitigate risk. Because future market conditions are unknown, the IPA employs a portfolio distribution schedule that allows between 20% and 40% of projected loads to be procured in each of the three years prior to the delivery month. Within this range, a three-year laddered procurement strategy would yield stable prices based on current market conditions:

   - 35% of projected energy needs procured two years in advance of the year of delivery;
   - 35% of projected energy needs procured one year in advance of delivery;
   - 30% of projected energy needs procured in the year in which power is to be delivered.

   Such a ladder provides a reasonable hedge while allowing sufficient flexibility in future procurement cycles to incorporate longer-term contracts for certain products should the planning process find that they are appropriate elements of the portfolio.

5. **Discussion of the results.** The analysis supports a recommendation of fixing the price of 30% of requirements in the procurement immediately prior to the delivery period, 35% one year earlier, and 35% two years earlier. This 30/35/35 model portfolio is analogous to dollar cost averaging in investing. This laddering of energy supply contracts does not apply to the purchase of renewable energy credits.

   Given the high-level nature of this analysis, the 30/35/35 recommendation can be thought of as representative of a range of procurement portfolios that may have very similar risk profiles. Leaving 5-10% of the procurement uncovered (i.e., taking it to spot) does not significantly increase risk exposure to customers based on model results. However, because buying wholesale block products to meet the customer load shape already subjects the Utilities to a significant amount of load balancing transactions in the spot market, additional exposure to the spot market is not recommended at this time.

It is important to remember that quantitative analysis is a modeling exercise based on historical patterns and assumptions about future load requirements. As such, the model cannot predict where prices will be in the next 3 to 5 year period. Instead, the model provides indications on how relative price volatility is managed under different portfolio distributions, thus meeting the IPA's charge to address price stability.

Capturing low costs is another issue. Qualitative evaluation of the current markets indicate that regulatory compliance may force a fair amount of coal generating assets out of the market within the next decade (or at least escalate their operating costs). Replacement baseload capacity has not appeared in the market. Most new "capacity" cited in reports is actually due to the high numbers of variable output wind and solar assets under development. While these assets are assigned a capacity factor, these assets are not suitable or sufficient to meet baseload electricity needs.

At this time, the market presents the probability of meeting replacement coal capacity, future load growth, and balancing variable output renewable assets with new or converted natural gas assets. While this forecast is not a certainty, it would be imprudent to ignore the cost impacts that such a future would hold for consumers. In this environment, the IPA recommends continued layering of future purchases ahead of the time when economic growth returns and the full impact of coal asset retirement is fully realized.

3.1.3 Recommendations.

The IPA recommends applying the standard laddered procurement approach to the Ameren and ComEd portfolios.

3.1.3.1 Treatment of Long Term Renewable Energy Contract Volumes.

The Utilities entered into 20-year supply contracts with approved renewable energy generators in December 2010. The vast majority of these contracts were for wind generation assets. Those contracts secured energy supply as well as associated Renewable Energy Credits (RECs) with deliveries to commence on June 1, 2012. The contract volumes in these contracts are arranged around an annual delivery volume with a plus or minus 10% volume allowance. The contracts do not require minimum monthly deliveries, or Peak and Off-Peak schedule

To accommodate scheduling around these contracts the IPA proposes the following methodology:

1. Establishing reasonable monthly delivery volume projections based on historical regional averages
2. Factoring those monthly delivery volume projections into Peak and Off Peak monthly delivery schedules
3. Adjusting the Peak and Off Peak monthly delivery schedules into average MW contract volumes
4. Including those averaged MW contract volumes into the Utilities procurement schedules

The IPA accessed data from PJM that reported the wind generated power outputs in the Commonwealth Edison region for the May 2009 through April 2011 period. That data is presented in Table F below:

TABLE F: HISTORICAL PJM WIND GENERATION FOR COMED REGION

Month	Wind Capacity (MW)	Total Generation (MWh)	Monthly Capacity Factor	Peak Generation (MWh)	Off-Peak Generation (MWh)	Peak Generation (%)	Off-Peak Generation (%)
May-09	905	185,631	27.6%	70,939	114,692	38.22%	61.78%
June-09	1,005	143,896	19.2%	61,497	82,399	42.74%	57.26%
July-09	1,005	101,897	13.6%	45,686	56,211	44.84%	55.16%
August-09	1,005	140,210	18.7%	46,163	94,047	32.92%	67.08%
September-09	1,005	89,208	11.9%	35,055	54,153	39.30%	60.70%
October-09	1,107	231,912	28.1%	114,569	117,343	49.40%	50.60%
November-09	1,158	292,437	33.9%	121,956	170,481	41.70%	58.30%
December-09	1,761	359,863	27.5%	169,632	190,231	47.14%	52.86%
January-10	1,761	360,050	27.5%	151,499	208,551	42.08%	57.92%
February-10	1,761	251,174	19.2%	123,093	128,081	49.01%	50.99%
March-10	1,761	322,013	24.6%	132,164	189,849	41.04%	58.96%
April-10	1,761	419,030	32.0%	195,790	223,240	46.72%	53.28%

May-10	1,761	318,265	24.3%	150,020	168,245	47.14%	52.86%
June-10	1,761	175,798	13.4%	78,803	96,995	44.83%	55.17%
July-10	2,199	170,025	10.4%	55,307	114,718	32.53%	67.47%
August-10	2,199	160,883	9.8%	60,190	100,693	37.41%	62.59%
September-10	2,199	319,094	19.5%	143,175	175,919	44.87%	55.13%
October-10	2,199	444,265	27.2%	179,547	264,718	40.41%	59.59%
November-10		462,977					
December-10	2,199	462,578	28.3%	207,535	255,043	44.86%	55.14%
January-11	2,199	372,536	22.8%	171,868	200,668	46.13%	53.87%
February-11	2,199	498,564	30.5%	239,124	259,440	47.96%	52.04%
March-11	2,199	478,052	29.2%	198,574	279,478	41.54%	58.46%
April-11	2,199	613,072	37.5%	270,141	342,931	44.06%	55.94%

The monthly capacity factors were averaged to generate a generic May through April capacity factor schedule. From that schedule, a generalized monthly volume allocation for wind outputs was established (in % of annual load). Then the Utility's long-term power purchase volumes were factored by the monthly percentages to establish a monthly renewable energy delivery volume. Those monthly renewable energy delivery volumes were then separated into Peak and Off Peak monthly allocations according to the averaged monthly Peak and Off-Peak allocations. The process of establishing the generic monthly allocations for ComEd are noted below in Table G:

TABLE G: CONVERSION OF HISTORICAL PJM WIND DATA TO COMED LONG TERM PPA MONTHLY NORMALIZED ALLOCATIONS

Month	Average Monthly Capacity Factor	Monthly Volume Allocation (% of Annual)	Monthly Volume Allocation (MWh)	Monthly Peak Period Volume Allocation (MWh)	Monthly Off Peak Period Volume Allocation (MWh)
May	25.9%	9.12%	115,069	49,107	65,962
June	16.3%	5.74%	72,451	31,720	40,731
July	12.0%	4.22%	53,288	20,613	32,675
August	14.3%	5.03%	63,413	22,301	41,112
September	15.7%	5.53%	69,744	29,350	40,394
October	27.7%	9.73%	122,717	55,110	67,607
November	31.1%	10.94%	138,034	59,747	78,287
December	25.1%	8.83%	111,464	51,982	59,481
January	29.0%	10.19%	128,590	57,891	70,699
February	24.2%	8.51%	107,372	48,610	58,762
March	31.0%	10.91%	137,681	58,588	79,093
April	32.0%	11.25%	141,902	66,303	75,599
TOTAL		**100.00%**	**1,261,725**	**551,322**	**710,403**

The process of establishing the generic monthly allocations for Ameren are noted below in Table H:

TABLE H: CONVERSION OF HISTORICAL PJM WIND DATA TO AMEREN LONG TERM PPA MONTHLY NORMALIZED ALLOCATIONS

Month	Average Monthly Capacity Factor	Monthly Volume Allocation (% of Annual)	Monthly Volume Allocation (MWH)	Monthly Peak Period Volume Allocation (MWh)	Monthly Off Peak Period Volume Allocation (MWh)
May	25.9%	9.12%	54,720	23,352	31,368
June	16.3%	5.74%	34,453	15,084	19,369
July	12.0%	4.22%	25,341	9,802	15,538
August	14.3%	5.03%	30,156	10,605	19,550
September	15.7%	5.53%	33,166	13,957	19,209
October	27.7%	9.73%	58,357	26,207	32,150
November	31.1%	10.94%	65,641	28,412	37,229
December	25.1%	8.83%	53,005	24,720	28,286
January	29.0%	10.19%	61,149	27,529	33,620
February	24.2%	8.51%	51,060	23,116	27,944
March	31.0%	10.91%	65,473	27,861	37,612
April	32.0%	11.25%	67,480	31,530	35,950
TOTAL		**100.00%**	**600,000**	**262,176**	**337,824**

The monthly Peak and Off-Peak allocations (in MWH) were then divided by the number of Peak and Off Peak hours expected for each of the months included in this Plan to calculate a MW volume. These MW volumes will be deducted from the targeted contract volumes for each Peak and Off-Peak period in each month between June 2012 and May 2017. The conversion of monthly Peak and Off Peak MWH contract volumes to MW contract volumes for ComEd for the months June 2012 through May 2015 is presented below in Table I:

TABLE I: APPLICATION OF MONTHLY NORMAL ALLOCATIONS TO CONVERSION OF HISTORICAL PJM WIND DATA TO COMED LONG TERM PPA MONTHLY NORMAL ALLOCATIONS (JUNE 2012 THROUGH MAY 2015)

Month	Monthly Peak Hours	Peak Renewable Volumes (MWh)	Average Monthly Peak Load (MW)	Monthly Off Peak Hours	Off Peak Renewable Volumes (MWh)	Average Monthly Off Peak Load (MW)
June-12	336	31,720	94	384	40,731	106
July-12	336	20,613	61	408	32,675	80
August-12	368	22,301	61	376	41,112	109
September-12	304	29,350	97	416	40,394	97
October-12	368	55,110	150	376	67,607	180
November-12	336	59,747	178	384	78,287	204
December-12	320	51,982	162	424	59,481	140
January-13	352	57,891	164	392	70,699	180
February-13	320	48,610	152	352	58,762	167
March-13	336	58,588	174	408	79,093	194
April-13	352	66,303	188	368	75,599	205
May-13	352	65,962	187	392	65,962	168
June-13	320	31,720	99	400	40,731	102
July-13	352	20,613	59	392	32,675	83
August-13	352	22,301	63	392	41,112	105
September-13	320	29,350	92	400	40,394	101
October-13	368	55,110	150	376	67,607	180
November-13	320	59,747	187	400	78,287	196

December-13	336	51,982	155	408	59,481	146
January-14	352	57,891	164	392	70,699	180
February-14	320	48,610	152	352	58,762	167
March-14	336	58,588	174	408	79,093	194
April-14	352	66,303	188	368	75,599	205
May-14	336	65,962	196	408	65,962	162
June-14	336	31,720	94	384	40,731	106
July-14	352	20,613	59	392	32,675	83
August-14	336	22,301	66	408	41,112	101
September-14	336	29,350	87	384	40,394	105
October-14	368	55,110	150	376	67,607	180
November-14	304	59,747	197	416	78,287	188
December-14	352	51,982	148	392	59,481	152
January-15	336	57,891	172	408	70,699	173
February-15	320	48,610	152	352	58,762	167
March-15	352	58,588	166	392	79,093	202
April-15	352	66,303	188	368	75,599	205
May-15	320	65,962	206	424	65,962	156

The conversion of monthly Peak and Off Peak MWH contract volumes to MW contract volumes for Ameren is presented below in Table J:

TABLE J: APPLICATION OF MONTHLY NORMAL ALLOCATIONS TO CONVERSION OF HISTORICAL PJM WIND DATA TO AMEREN LONG TERM PPA MONTHLY NORMAL ALLOCATIONS (JUNE 2012 THROUGH MAY 2015)

Month	Monthly Peak Hours	Peak Renewable Energy Volumes (MWh)	Average Monthly Peak Load (MW)	Monthly Off Peak Hours	Off Peak Renewable Energy Volumes (MWh)	Average Monthly Off Peak Load (MW)
June-12	336	15,084	45	384	19,369	50
July-12	336	9,802	29	408	15,538	38
August-12	368	10,605	29	376	19,550	52
September-12	304	13,957	46	416	19,209	46
October-12	368	26,207	71	376	32,150	86
November-12	336	28,412	85	384	37,229	97
December-12	320	24,720	77	424	28,286	67
January-13	352	27,529	78	392	33,620	86
February-13	320	23,116	72	352	27,944	79
March-13	336	27,861	83	408	37,612	92
April-13	352	31,530	90	368	35,950	98
May-13	352	23,352	66	392	31,368	80
June-13	320	15,084	47	400	19,369	48
July-13	352	9,802	28	392	15,538	40
August-13	352	10,605	30	392	19,550	50
September-13	320	13,957	44	400	19,209	48
October-13	368	26,207	71	376	32,150	86
November-13	320	28,412	89	400	37,229	93
December-13	336	24,720	74	408	28,286	69
January-14	352	27,529	78	392	33,620	86
February-14	320	23,116	72	352	27,944	79

March-14	336	27,861	83	408	37,612	92
April-14	352	31,530	90	368	35,950	98
May-14	336	23,352	70	408	31,368	77
June-14	336	15,084	45	384	19,369	50
July-14	352	9,802	28	392	15,538	40
August-14	336	10,605	32	408	19,550	48
September-14	336	13,957	42	384	19,209	50
October-14	368	26,207	71	376	32,150	86
November-14	304	28,412	93	416	37,229	89
December-14	352	24,720	70	392	28,286	72
January-15	336	27,529	82	408	33,620	82
February-15	320	23,116	72	352	27,944	79
March-15	352	27,861	79	392	37,612	96
April-15	352	31,530	90	368	35,950	98
May-15	320	23,352	73	424	31,368	74

3.1.3.2 Ameren Illinois Company. The IPA selected Ameren's Expected load model as the basis of the Plan. The Expected model volumes are adjusted to account for energy efficiency program results, but not for Demand Response. Additionally, the contract volumes attributable to Long-term Power Purchase Agreements entered into by Ameren in December 2010 are estimated and counted as existing energy purchases for hedging purposes.

In response to Section 8-103(c) of the PUA, Ameren factors its load projections to account for the Utility's demand response programs. Section 8-103(c) of the PUA directs:

> *"Electric Utilities shall implement cost-effective demand-response measures to reduce peak demand by 0.1% over the prior year for eligible retail customers, as defined in Sections 16-111.5 of this Act and for customers that elect hourly service from the utility pursuant to Section 16-107 of this Act, provided those customers have not been declared competitive. This requirement commences June 1, 2008 and continues for 10 years."*[130]

Section 16-111.5(b) of the PUA requires that the procurement plan shall include an analysis of the impact of demand side initiatives established by Section 8-103(c) of the PUA. Those demand side initiatives include the impact of demand response programs and the impact of energy efficiency programs (both current and projected). Recent activity in ICC Docket No. 10-0568 leads the IPA to conclude that Ameren does not have a valid demand response program. Specifically, the IPA notes that the Commission rejected Ameren's request for a proposed Voltage Optimization program, stating it was "not convinced" that by implementing energy efficiency measures Ameren would meet the Section 8-103(c) demand response requirements:[131]

> *"The Commission is of the opinion that it would be appropriate to institute a pilot of the Voltage Optimization Program, to determine what the benefits would be of a wider adoption of this program. The Commission agrees with Staff that the pilot should include testing not only the demand response capabilities of the program, but also the energy efficiency capabilities, if implemented on a continuous basis. The Commission suggests Ameren conduct a pilot of the Voltage Optimization Program on a heavily loaded feeder that is able to support a significant reduction in voltage in order to maximize the cost-effectiveness of the pilot. The Commission further suggests Ameren design a number of tests using industry best practices that can be used to ensure the demand response capabilities of the pilot program will actually work. The Commission believes that the adoption of a pilot program, with the remainder of the funds directed toward greater energy efficiency, along with other possible demand-response measures, will be appropriate at this time. With these measures in place, the Commission does not find it necessary at this time to direct the IPA to acquire demand response, although this may become necessary in the future."*

[130] 220 ILCS 5/8-103(c).

[131] Final Order at 27-28, ICC Docket No. 10-0568.

For the purpose of projecting loads for this year's Plan, the IPA assumes that Ameren will not deliver the required demand response reductions to the portfolio as in the 2009, 2010, and 2011 plan years.

The IPA has included the impacts of the Ameren energy efficiency programs based on their analysis of the current and projected programs. The annual incremental reductions in Ameren's supply requirements to be acquired through the RFP process (net of customer switching) is projected to be for 2012 (159,162 MWh) for 2013 (134,341 MWh), for 2014 (130,399 MWh) for 2015 (127,850 MWh), and for 2016 (124,204 MWh).

The IPA will request validation of the avoided energy consumption delivered by these programs in the near future. The IPA also notes that these Energy Efficiency values are effectively treated as all other legacy supply contracts within the supply resources projections for the Utility.

Ameren Illinois Company will secure the physical energy resources to meet the combine load requirements of eligible retail customers. For the purposes of this Plan, the following Ameren customer rate classes for which supply will be procured are defined as follows:

- **DS-1** – Residential
- **DS-2** – Non residential, less than 150 kW peak demand
- **DS-3a** – Non residential, between 151 kW and 400 kW peak demand
- **DS-5** – Lighting services
- **QF** – Qualified Facilities. Under Rider QF, such qualifying purchases are considered to be preexisting purchases and shall be recovered in Accrued Expenses for the Purchased Electricity Adjustment.[132]

Table K presents Ameren's consolidated monthly volume schedule for each included rate class for the first three years covered by this five-year Plan. This Data was updated by Ameren on November 10, 2011. Data for the entire sixty (60) months covered by this plan for Ameren can be found in Attachment C. IPA notes that Ameren's DS-3a rate class was declared competitive on May 1, 2011. The declaration allows for a three year transition period such that effective May 1, 2014 all load for this rate class must be served by ARES or Ameren real time pricing tariffs.

TABLE K: VOLUME PROJECTIONS PER RATE CLASS FOR AMEREN (JUNE 2012 THROUGH MAY 2015) (As of November 11, 2011)

[132] Sheet 31.003 of the Rider PER tariff.

Projected Monthly Volume Requirements							
Contract Month	DS1 MWH	DS2 MWH	DS3a MWH	DS5 MWH	QF MWH	Total Load MWH	Net Load MWh
June-12	981,549	258,988	41,418	25,401	(41,040)	1,307,356	1,266,316
July-12	1,294,257	285,908	44,630	24,942	(42,408)	1,649,736	1,607,328
August-12	1,282,950	282,318	42,873	26,165	(42,408)	1,634,306	1,591,898
September-12	901,988	243,839	39,011	29,237	(41,040)	1,214,075	1,173,035
October-12	746,174	226,188	38,633	31,413	(42,408)	1,042,407	999,999
November-12	811,999	215,111	35,950	35,090	(41,040)	1,098,151	1,057,111
December-12	1,107,911	244,305	37,374	38,497	(42,408)	1,428,087	1,385,679
January-13	1,189,471	250,357	36,509	41,282	(42,408)	1,517,619	1,475,211
February-13	967,002	232,969	33,303	36,275	(38,304)	1,269,549	1,231,245
March-13	887,978	230,974	33,967	32,566	(42,408)	1,185,486	1,143,078
April-13	681,257	205,299	30,635	30,265	(41,040)	947,455	906,415
May-13	710,264	214,622	32,585	27,218	(42,408)	984,690	942,282
June-13	961,907	244,716	34,592	25,265	0	1,266,481	1,266,481
July-13	1,268,660	271,253	37,745	24,625	0	1,602,282	1,602,282
August-13	1,258,286	269,331	36,787	26,008	0	1,590,412	1,590,412
September-13	883,717	234,121	33,995	28,742	0	1,180,576	1,180,576
October-13	728,503	218,391	34,175	31,249	0	1,012,319	1,012,319
November-13	793,756	209,133	32,318	34,847	0	1,070,054	1,070,054
December-13	1,086,578	238,122	34,030	38,396	0	1,397,126	1,397,126
January-14	1,164,323	244,130	29,314	41,178	0	1,478,945	1,478,945
February-14	946,928	228,568	23,162	36,164	0	1,234,823	1,234,823
March-14	869,464	226,315	19,690	32,372	0	1,147,842	1,147,842
April-14	667,017	201,395	14,228	30,137	0	912,776	912,776
May-14	696,177	210,773	0	27,132	0	934,082	934,082
June-14	944,115	240,008	0	25,174	0	1,209,297	1,209,297
July-14	1,248,093	265,747	0	24,542	0	1,538,382	1,538,382
August-14	1,239,410	263,786	0	25,890	0	1,529,086	1,529,086
September-14	870,532	229,355	0	28,640	0	1,128,527	1,128,527
October-14	717,092	213,944	0	31,186	0	962,222	962,222
November-14	782,094	204,546	0	34,777	0	1,021,417	1,021,417
December-14	1,073,037	233,009	0	38,315	0	1,344,361	1,344,361
January-15	1,129,126	239,671	0	41,097	0	1,409,895	1,409,895
February-15	918,465	223,837	0	36,069	0	1,178,371	1,178,371
March-15	844,324	221,570	0	32,295	0	1,098,188	1,098,188
April-15	650,081	197,153	0	30,094	0	877,328	877,328
May-15	682,348	206,207	0	27,053	0	915,608	915,608

The monthly volumes presented above for the various rate classed are aggregated and set alongside the representative monthly Peak and Off-Peak Average Load in Table L below with the full 2012 to 2017 planning period presented in Attachment D.

TABLE L: AGGREGATED MONTHLY AND AVERAGE LOAD REQUIREMENTS FOR AMEREN (JUNE 2012 THROUGH MAY 2015)

Contract Month	Total Load (MWh)		Average Load	
	On Peak	Off Peak	On Peak	Off Peak
Jun-12	686,633	579,683	2,044	1,510
Jul-12	820,066	787,262	2,441	1,930
Aug-12	887,301	704,597	2,411	1,874
Sep-12	564,609	608,426	1,857	1,463
Oct-12	544,848	455,152	1,481	1,211
Nov-12	539,505	517,605	1,606	1,348
Dec-12	639,722	745,957	1,999	1,759
Jan-13	730,322	744,888	2,075	1,900
Feb-13	621,688	609,557	1,943	1,732
Mar-13	546,456	596,621	1,626	1,462
Apr-13	474,852	431,563	1,349	1,173
May-13	485,816	456,466	1,380	1,164
Jun-13	645,637	620,844	2,018	1,552
Jul-13	851,072	751,211	2,418	1,916
Aug-13	861,894	728,519	2,449	1,858
Sep-13	576,046	604,530	1,800	1,511
Oct-13	541,895	470,424	1,473	1,251
Nov-13	509,990	560,064	1,594	1,400
Dec-13	664,146	732,980	1,977	1,797
Jan-14	729,063	749,882	2,071	1,913
Feb-14	620,277	614,546	1,938	1,746
Mar-14	538,958	608,883	1,604	1,492
Apr-14	475,534	437,242	1,351	1,188
May-14	443,915	490,166	1,321	1,201
Jun-14	618,823	590,473	1,842	1,538
Jul-14	819,986	718,396	2,330	1,833
Aug-14	778,408	750,678	2,317	1,840
Sep-14	568,863	559,665	1,693	1,457
Oct-14	512,001	450,221	1,391	1,197
Nov-14	455,412	566,006	1,498	1,361
Dec-14	669,902	674,459	1,903	1,721
Jan-15	657,019	752,875	1,955	1,845
Feb-15	586,195	592,176	1,832	1,682
Mar-15	542,051	556,137	1,540	1,419
Apr-15	458,819	418,509	1,303	1,137
May-15	416,994	498,614	1,303	1,176

Energy and financial hedges required by the Eligible Retail Customers comes from six sources. First, the swap contract with Ameren Energy Marketing provides a financial hedge on 1,000 MW of Around-the-Clock ("ATC") energy during the June 2012 – December 2012 period. Second, financial hedges are in place for the period June 2012 through May 2013 with such hedges resulting from the 2010 procurement processes. Third, fixed price physical supply contracts for the period June 2012 through May 2014 resulted from the 2011 procurement process. Fourth, Ameren Illinois Company will hedge price exposure for Residual Volumes (IPA will solicit standard wholesale products through a sealed-bid RFP per this Plan) using fixed price physical supply contracts. Fifth, long term renewable contracts resulting from the 2010 procurement process are in place for both energy and RECs (twenty year term). The volume associated with long term renewable contracts are estimated and subtracted from the projections. Sixth, Ameren Illinois will procure the physical energy necessary to meet their combined load requirements via the MISO day ahead and real-time energy markets.

A financial swap is a commercial transaction between two parties involving the exchange (swap) of risk. In this instance, Ameren Illinois desires to pay a fixed price, and will settle all loads with the MISO at LMP. Under a swap transaction Ameren Illinois will pay a fixed price to their supplier in exchange for receiving a floating price (MISO LMPs) from the supplier. As such, the LMP paid by Ameren Illinois to the MISO is offset by the LMP received from the supplier, leaving Ameren Illinois only paying the fixed price. Financial swaps provide the same level of hedging as physical transactions.

The use of financial swaps will not adversely affect reliability as Ameren Illinois will contract for sufficient capacity to meet the load obligations, and the contracts for such capacity shall obligate the seller to offer capacity into the MISO markets.

However, due to uncertainty concerning the viability and practicality of financial swap contracts, primarily due to the recent passage of the Dodd–Frank Wall Street Reform and Consumer Protection Act (Public Law 111-203, H.R. 4173), the IPA shall authorize the procurement administrator to issue contracts for the physical delivery of energy, instead of a financial swap contracts, if during procurement preparations it becomes clear to the procurement administrator that contracts for the physical delivery are more likely to be in the interests of the utility and ratepayers. Furthermore, if the procurement administrator, after consultation with the IPA, Utilities, Commission, and procurement monitor, determines that financial swap contracts are still preferable to contracts for physical delivery of energy, the procurement administrator will still be instructed to fashion the swap contracts to allow for conversion to physical delivery contracts if at some point in the future such conversion is seen to be advantageous to both buyer and seller.

In determining the granularity of the standard wholesale products to be procured through the RFP, the IPA recognized that if the products are defined in a way such that the megawatt amount contracted in each given hour is equal to the actual customer load in that hour, then the wholesale products will effectively provide price stability for customers because the fluctuations in the cost to supply the load will effectively be hedged. Yet, standard products traded in the wholesale market do not involve delivery quantities that vary within the twenty-four (24) monthly on-peak/off-peak periods throughout the year, so the quantities of energy procured in the form of standard wholesale products cannot approximate customer load shapes on a more granular basis than a monthly on-peak/off-peak basis.

Given these facts, the IPA's procurement administrator will issue solicitations to lock-in fixed prices for fixed quantities of energy supply, using single-month, multi-month, and/or annual contracts for on-peak, off-peak, and/or around-the-clock blocks during the period between June 2012 and May 2015, in whatever combinations are deemed appropriate by the procurement administrator, given the objectives described in this plan. The target procurement quantities are determined by multiplying Ameren's average net load obligation (average forecasted load) in each monthly on-peak/off-peak period by the targeted hedge position after the procurement event is completed (i.e. 35% for requirements two years out, 70% for requirements one year out, and 100% for requirements in the year in which power is delivered).

Next, MWs covered by the Ameren Energy Marketing swap are subtracted from the target requirements, as well as those MWs covered as a result of the 2010 and 2011 procurement plans. These procurement plans included block purchases using both swaps and physical settlement, as well as variable purchases of energy from renewable facilities. To the extent the calculated procurement quantity for a period is less than zero, no energy will be procured for that period and existing positions will be maintained. Also, note that calculations in the model are rounded to the nearest 50 MW. By procuring a portfolio of the most granular standard wholesale products available and in quantities reflective of forecasted loads, the forecasted net amount of energy transacted in the volatile spot market will be minimized.

Bidders will be provided an opportunity to bundle their bids for various products as determined by the procurement administrator after consulting with the IPA, Ameren Illinois, the procurement monitor and the Commission. By providing some flexibility for bundled bids, bidders will be better able to bid on the products for which they can offer the most competitive prices. The procurement administrator will accept the bids that together represent the lowest cost portfolio of products that provide the desired monthly on-peak and off-peak quantities being solicited through the RFP, provided that other legal standards in the PUA are followed.

Based on the current load forecast, the quantities of standard wholesale energy products to be procured through the sealed-bid RFP are as follows (rounded to the nearest 50 MW) are found in Tables M and N. A full schedule of related planned procurement loads for Ameren can be found in Attachments E and F.

TABLE M: PROPOSED AMEREN OFF-PEAK LOAD VOLUMES TO BE SECURED IN 2012 CYCLE

Off Peak Contract Volumes to Secure (MW)

Contract Month	Projected Volumes (MW)	Swap Volume (MW)	2010 Portfolio Volume (MW)	2011 Portfolio Volume (MW)	LT Wind Portfolio Volume (MW)	Residual Volume (MW)	2012 IPA Procurement (MW)
Jun-12	1,510	1,000	0	150	50	310	300
Jul-12	1,930	1,000	0	450	38	442	450
Aug-12	1,874	1,000	0	400	52	422	400
Sep-12	1,463	1,000	0	200	46	217	200
Oct-12	1,211	1,000	0	0	86	125	100
Nov-12	1,348	1,000	0	50	97	201	200
Dec-12	1,759	1,000	0	300	67	392	400
Jan-13	1,900	0	750	250	86	814	800
Feb-13	1,732	0	700	250	79	703	700
Mar-13	1,462	0	600	500	92	270	250
Apr-13	1,173	0	500	450	98	125	100
May-13	1,164	0	500	450	80	134	150
Jun-13	1,552	0	0	550	48	954	500
Jul-13	1,916	0	0	700	40	1,176	600
Aug-13	1,858	0	0	700	50	1,108	550
Sep-13	1,511	0	0	600	48	863	400
Oct-13	1,251	0	0	500	86	665	300
Nov-13	1,400	0	0	500	93	807	400
Dec-13	1,797	0	0	650	69	1,078	550
Jan-14	1,913	0	0	700	86	1,127	550
Feb-14	1,746	0	0	650	79	1,017	500
Mar-14	1,492	0	0	550	92	850	400
Apr-14	1,188	0	0	450	98	640	300
May-14	1,201	0	0	450	77	674	300
Jun-14	1,538	0	0	0	50	1,488	500
Jul-14	1,833	0	0	0	40	1,793	600
Aug-14	1,840	0	0	0	48	1,792	600
Sep-14	1,457	0	0	0	50	1,407	450
Oct-14	1,197	0	0	0	86	1,111	350
Nov-14	1,361	0	0	0	89	1,272	400
Dec-14	1,721	0	0	0	72	1,649	550
Jan-15	1,845	0	0	0	82	1,763	550
Feb-15	1,682	0	0	0	79	1,603	500
Mar-15	1,419	0	0	0	96	1,323	400
Apr-15	1,137	0	0	0	98	1,039	300
May-15	1,176	0	0	0	74	1,102	350

Off Peak Contract Volumes to Secure (MW)

Contract Month	Projected Volumes (MW)	Swap Volume (MW)	2010 Portfolio Volume (MW)	2011 Portfolio Volume (MW)	LT Wind Portfolio Volume (MW)	Residual Volume (MW)	2012 IPA Procurement (MW)
Jun-15	1,497	0	0	0	53	1,444	0
Jul-15	1,807	0	0	0	41	1,766	0
Aug-15	1,847	0	0	0	48	1,799	0

Sep-15	1,397	0	0	0	50	1,347	0
Oct-15	1,168	0	0	0	82	1,086	0
Nov-15	1,309	0	0	0	93	1,216	0
Dec-15	1,661	0	0	0	72	1,589	0
Jan-16	1,839	0	0	0	79	1,760	0
Feb-16	1,666	0	0	0	78	1,588	0
Mar-16	1,379	0	0	0	100	1,279	0
Apr-16	1,129	0	0	0	94	1,035	0
May-16	1,138	0	0	0	77	1,061	0
Jun-16	1,507	0	0	0	53	1,454	0
Jul-16	1,798	0	0	0	37	1,761	0
Aug-16	1,791	0	0	0	52	1,739	0
Sep-16	1,378	0	0	0	50	1,328	0
Oct-16	1,142	0	0	0	79	1,063	0
Nov-16	1,282	0	0	0	97	1,185	0
Dec-16	1,645	0	0	0	69	1,576	0
Jan-17	1,778	0	0	0	82	1,696	0
Feb-17	1,636	0	0	0	79	1,557	0
Mar-17	1,366	0	0	0	100	1,266	0
Apr-17	1,119	0	0	0	90	1,029	0
May-17	1,103	0	0	0	80	1,023	0

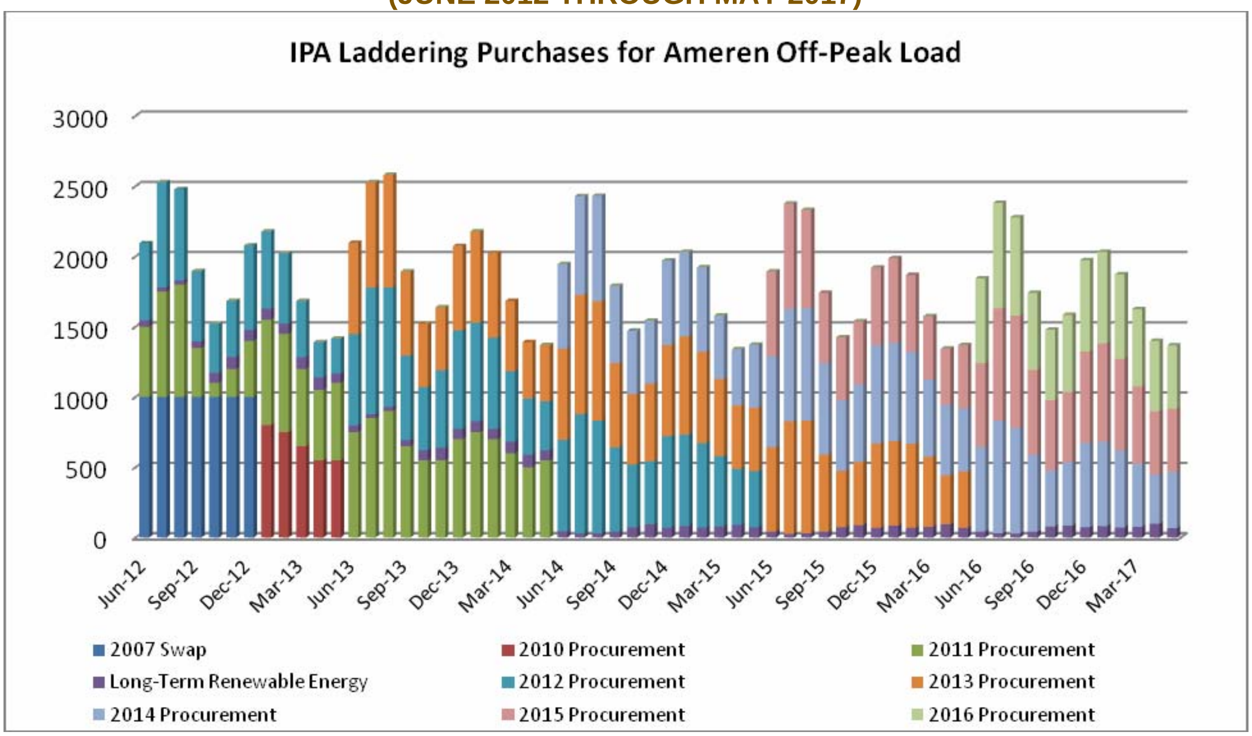
TABLE N: PROPOSED AMEREN PEAK LOAD VOLUMES TO BE SECURED IN 2012 CYCLE

Peak Contract Volumes to Secure (MW)							
Contract Month	Projected Volumes (MW)	Swap Volume (MW)	2010 Portfolio Volume (MW)	2011 Portfolio Volume (MW)	LT Wind Portfolio Volume (MW)	Residual Volume (MW)	2012 IPA Procurement (MW)
Jun-12	2,044	1,000	0	500	45	499	500
Jul-12	2,441	1,000	0	750	29	662	650
Aug-12	2,411	1,000	0	800	29	582	600
Sep-12	1,857	1,000	0	350	46	461	450
Oct-12	1,481	1,000	0	100	71	310	300
Nov-12	1,606	1,000	0	200	85	321	300
Dec-12	1,999	1,000	0	400	77	522	500
Jan-13	2,075	0	800	750	78	447	450
Feb-13	1,943	0	750	700	72	421	400
Mar-13	1,626	0	650	550	83	343	350
Apr-13	1,349	0	550	500	90	209	200
May-13	1,380	0	550	550	66	214	200
Jun-13	2,018	0	0	750	47	1,221	600
Jul-13	2,418	0	0	850	28	1,540	800
Aug-13	2,449	0	0	900	30	1,519	800
Sep-13	1,800	0	0	650	44	1,106	550
Oct-13	1,473	0	0	550	71	852	400
Nov-13	1,594	0	0	550	89	955	500
Dec-13	1,977	0	0	700	74	1,203	600
Jan-14	2,071	0	0	750	78	1,243	600
Feb-14	1,938	0	0	700	72	1,166	600
Mar-14	1,604	0	0	600	83	921	450
Apr-14	1,351	0	0	500	90	761	350
May-14	1,321	0	0	550	70	701	300
Jun-14	1,842	0	0	0	45	1,797	600
Jul-14	2,330	0	0	0	28	2,302	800
Aug-14	2,317	0	0	0	32	2,285	800
Sep-14	1,693	0	0	0	42	1,651	550
Oct-14	1,391	0	0	0	71	1,320	400
Nov-14	1,498	0	0	0	93	1,405	450
Dec-14	1,903	0	0	0	70	1,833	600
Jan-15	1,955	0	0	0	82	1,873	600
Feb-15	1,832	0	0	0	72	1,760	550
Mar-15	1,540	0	0	0	79	1,461	450
Apr-15	1,303	0	0	0	90	1,213	350
May-15	1,303	0	0	0	73	1,230	400

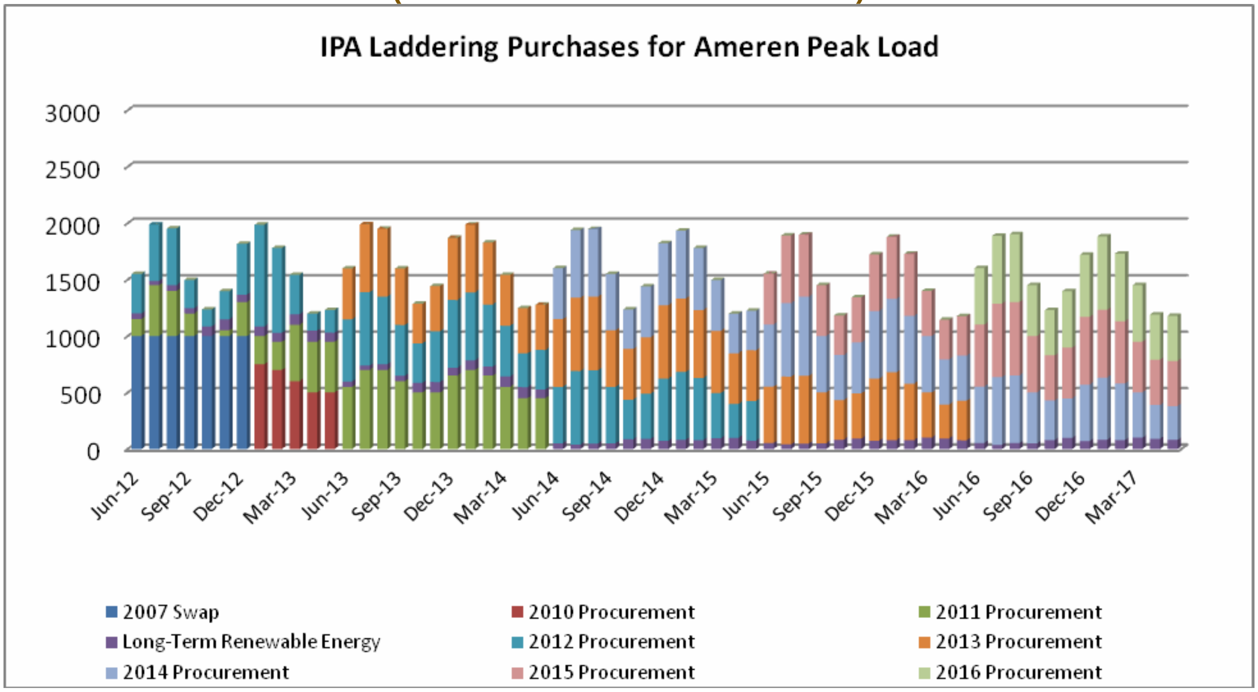
Peak Contract Volumes to Secure (MW)							
Contract Month	Projected Volumes (MW)	Swap Volume (MW)	2010 Portfolio Volume (MW)	2011 Portfolio Volume (MW)	LT Wind Portfolio Volume (MW)	Residual Volume (MW)	2012 IPA Procurement (MW)
Jun-15	1,808	0	0	0	43	1,765	0
Jul-15	2,263	0	0	0	27	2,236	0
Aug-15	2,223	0	0	0	32	2,191	0
Sep-15	1,700	0	0	0	42	1,658	0
Oct-15	1,376	0	0	0	74	1,302	0
Nov-15	1,479	0	0	0	89	1,390	0

Dec-15	1,872	0	0	0	70	1,802	0
Jan-16	1,928	0	0	0	86	1,842	0
Feb-16	1,806	0	0	0	69	1,737	0
Mar-16	1,552	0	0	0	76	1,476	0
Apr-16	1,295	0	0	0	94	1,201	0
May-16	1,317	0	0	0	70	1,247	0
Jun-16	1,771	0	0	0	43	1,728	0
Jul-16	2,309	0	0	0	31	2,278	0
Aug-16	2,218	0	0	0	29	2,189	0
Sep-16	1,695	0	0	0	42	1,653	0
Oct-16	1,388	0	0	0	78	1,310	0
Nov-16	1,471	0	0	0	85	1,386	0
Dec-16	1,863	0	0	0	74	1,789	0
Jan-17	1,950	0	0	0	82	1,868	0
Feb-17	1,804	0	0	0	72	1,732	0
Mar-17	1,525	0	0	0	76	1,449	0
Apr-17	1,287	0	0	0	99	1,188	0
May-17	1,326	0	0	0	66	1,260	0

GRAPH 2: PROPOSED LADDERING SCHEDULE FOR AMEREN OFF-PEAK LOAD (JUNE 2012 THROUGH MAY 2017)



GRAPH 3: PROPOSED LADDERING SCHEDULE FOR AMEREN PEAK LOAD (JUNE 2012 THROUGH MAY 2017)



The PUA provides that it is the duty of the Procurement Administrator, in consultation with the Commission, Ameren, and other interested parties, to develop the standard contract form that will be used for the standard wholesale products to be procured through the RFP.[133]

The standard wholesale products to be procured through the RFP could be settled physically or financially. In both cases, Ameren would contract to purchase or hedge specific quantities of energy at fixed prices.

In the case of financial settlement, Ameren would procure energy in the day-ahead or real-time markets, and debit or credit a dollar amount to the seller based on the difference between the agreed-upon fixed contract price and an index price, whereby the index price would be specified in the contract to be either the day-ahead or real-time energy price. Financial contracts are generally referred to as "contracts for differences". The swap contract with Ameren Energy Marketing is an example of a financially-settled contract.

In the case of physical settlement, the contracting parties would transact through MISO. In this case, both parties must be MISO members in good standing. Ameren and the seller would execute an agreement, under which the seller transfers energy to Ameren via a MISO process. Ameren would then directly pay the seller the agreed-upon fixed contract price for the specified amount of energy.

The choice between settling physically and financially does not affect service reliability. Whether the products settle physically or financially, MISO will still dispatch the system in such a way to ensure that customers' requirements are met. The decision to settle physically or financially affects the logistics regarding cash flows, the administrative tasks that are required of the various parties involved, the non-performance risks and the standard of legal review.

The IPA makes note that federal legislation regarding the regulation of derivatives has recently passed and is currently going through a rule making process. It is expected that such legislation will allow the CFTC to

[133] 220 ILCS 5/16-111.5(e)(2).

regulate derivatives (including financial swaps) and enforce position limits, margin requirements and reporting requirements. Such changes have the potential to increase costs for Ameren Illinois, its suppliers and customers. The date of the final rule making is uncertain and it is unclear if final rules will exempt existing financial swap transactions via a “grandfather” clause. It is also uncertain whether Ameren Illinois will be partially or completely exempt from the rule making outcome since Ameren Illinois may be viewed as an end user and not a speculator. In summary and in light of the information currently available, the IPA recommends that the spring 2012 procurement event continue the process established in the spring 2011 procurement event whereby financial swaps were replaced with those that settle physically within MISO. This would appear to be the most prudent course of action until the rule making process is better understood. However, if the procurement administrator, after consultation with the IPA, utilities, Commission, and procurement monitor, determines that financial swap contracts are preferable to contracts for physical delivery of energy, the procurement administrator will be instructed to fashion the swap contract, as previously noted in the Plan. The IPA will monitor the rule making process and recommend a course of action for procurement events beyond spring 2012 as the outcome of the current rule making process becomes clearer.

Additional elements to the supply resources plan include:

Load Balancing Procedures. Upon Commission approval of this Plan, Ameren will enter into fixed price transactions that settle physically within MISO. This will act as a hedge for the energy price risk of the portfolio since 100% of the actual energy required to supply the load included in this Plan will be purchased in the MISO energy markets with such pricing varying from hour to hour. Ameren will forecast respective load requirements for each delivery day in accordance with industry standards and practices for each delivery day. These forecasts will be utilized to submit a day-ahead demand bid to the MISO market, which will be settled with the MISO at a price equal to the MISO day-ahead LMPs for each hour.

Hourly balancing will be performed through the MISO real time energy market, with deviations from the day-ahead demand bid settling at a price equal to the MISO real-time LMP. MISO charges, including Revenue Neutrality Uplift and Revenue Sufficiency Guarantee payments will also apply

Portfolio Rebalancing in the Event of Significant Shifts in Load. The PUA requires that the IPA provide the criteria for portfolio rebalancing in the event of significant shifts in load. Shifts in load are incorporated into the utility-prepared forecasts used in the IPA’s plans. However, the IPA recognizes that between the time that each plan’s forecasts are prepared and the time that the relevant portion of the plan is implemented, the conditions underlying those forecasts can and do change. Thus, between March 1 and March 10, the IPA recommends that Ameren submit to the IPA and to Commission staff a revised base-case forecast of monthly on-peak and off-peak loads encompassing the first three years of the five-year planning horizon. Since a significant driver of load shifting is customer switching to alternative retail electric suppliers and, more recently, to municipal aggregation programs, the IPA recommends that Ameren pay particular attention to these factors. It is also recommended that Ameren survey the actual number and size of the municipalities that have at that time filed with the relevant election authority to hold, or have already passed referenda, approving “opt out” aggregation. Based on the information provided by Ameren, the IPA will work with Ameren, the Commission staff and the procurement administrator and monitor to revise the volumes of products that will be sought through the spring procurement events, but only if a consensus is reached..

Intercompany Dynamics Cost and Resource Sharing. In late 2010, Ameren completed an internal merger of its three legacy Illinois utilities into Ameren Illinois Company. Therefore, Ameren will purchase as one entity and the language in previous plans regarding intercompany dynamics cost and resource sharing is therefore no longer applicable.

Contingency Procurement Plan. Ameren Rider PER (Purchased Energy Recovery) (Electric Service Schedule Ill.CC. No. 18) will serve as the basis of the Contingency Procurement Plan.

3.1.3.3 Commonwealth Edison. The IPA selects the Expected Load Model as the basis of the procurement plan for the ComEd portfolio. The Expected Load model volumes are adjusted to account for energy efficiency program and demand response results. Additionally, the contract volumes attributable to Long-term Power Purchase Agreements entered into by ComEd in December 2010 are factored out of the projection.

In response to Section 8-103(c) of the PUA, ComEd factors its load projections to account for the Utility's demand response programs. Section 8-103(c) of the PUA directs:

> *"Electric Utilities shall implement cost-effective demand-response measures to reduce peak demand by 0.1% over the prior year for eligible retail customers, as defined in Sections 16-111.5 of this Act and for customers that elect hourly service from the utility pursuant to Section 16-107 of this Act, provided those customers have not been declared competitive. This requirement commences June 1, 2008 and continues for 10 years."*[134]

Section 16-111.5(b) of the PUA requires that the procurement plan shall include an analysis of the impact of demand side initiatives established by Section 8-103(b) and (c) of the PUA. Those demand side initiatives include the impact of demand response programs both current and projected) and the impact of energy efficiency programs (both current and projected). For the purpose of projecting loads for this year's Plan, the IPA assumes that ComEd intends to implement demand response programs sufficient to achieve their targeted peak reductions. Based on ComEd's analysis, the effective aggregated reduction in ComEd's maximum system load requirements for eligible retail customers due to demand response programs is projected to be for 2012 (10.7 MW), for 2013 (10.8 MW), for 2014 (7.0 MW), for 2015 (7.0 MW), and for 2016 (7.1 MW).

The IPA anticipates requesting validation of the ability to dispatch the Energy Efficiency assets included in the forecast in the near future.

Section 8-103(b) of the PUA also establishes specific requirements for energy efficiency programs that reduce energy consumption of delivery services customers by 0.2% in the 2008 planning year and by an additional 0.2% each year through 2012, growing to a total decrease in energy consumption of 2.0% in 2015 and thereafter.[135] The annual aggregate reductions in ComEd's supply requirements to be acquired through the RFP process (net of customer switching) is projected to be for 2012 (756 GWh), for 2013 (934 GWh), for 2014 (1,117 GWh), for 2015 (1,288 GWh), and for 2016 (1,471 GWh).

The IPA anticipates requesting validation of the ability to dispatch the Demand Response assets included in the forecast in the near future. The IPA also notes that these Energy Efficiency values are effectively treated as all other legacy supply contracts within the Supply Resources projections for the Utility.

ComEd Energy Supply Resources. ComEd will meet the physical supply requirements of the projected loads for specific rate classes as identified in the Load Forecast report submitted by ComEd to the IPA a copy of which can be found in Attachment E of this document. The Tables below present the consolidated consumption projections for the five year period covered in the Plan. ComEd customer rate classes are defined as follows:

- **SF -** Single-family residential, non-electric space heating
- **MF -** Multi-family residential, non-electric space heating
- **SFSH -** Single-family residential, electric space heating
- **MFSH -** Multi-family residential, electric space heating
- **WH –** Watt-Hour, non-residential, consumption of less than 2,000 kWh per billing period
- **Small –** Small Load, non-residential, less than 100 kW peak demand
- **DD –** Dusk to Dawn Lighting
- **GL –** General Lighting

Table O presents ComEd's consolidated monthly volume schedule for each rate class for the first 12 months of the period covered by this Plan. Volumes include on-peak as well as off-peak periods, and are adjusted for eligibility and projected switching activity. Tabular data for all sixty (60) months covered by this plan can be found in Attachment G.

[134] 220 ILCS 5/8-103(c).
[135] 220 ILCS 5/8-103(b).

TABLE O: VOLUME PROJECTIONS PER RATE CLASS FOR COMED (JUNE 2012 THROUGH MAY 2015)

Contract Month	Projected Monthly Volume Requirements									
	SF MWh	MF MWh	SFSH MWh	MFSH MWh	WH MWh	Small MWh	Condo MWh	DD MWh	GL MWh	Total MWh
12-Jun	1,803,202	393,843	42,644	94,682	34,690	465,273	17,028	8,039	1,245	2,860,645
12-Jul	2,320,581	504,385	42,517	101,391	37,632	497,643	18,675	8,252	1,278	3,532,353
12-Aug	2,087,645	466,960	37,320	92,188	37,017	487,674	18,756	8,774	1,359	3,237,692
12-Sep	1,295,555	298,458	24,966	62,012	30,841	416,476	16,362	8,845	1,370	2,154,885
12-Oct	1,042,736	242,638	28,565	62,892	28,656	393,326	15,911	9,795	1,517	1,826,036
12-Nov	986,915	222,164	43,343	87,775	25,399	365,654	15,440	9,944	1,540	1,758,172
12-Dec	1,182,212	252,932	66,506	142,653	27,613	388,652	19,947	10,530	1,631	2,092,677
13-Jan	1,165,345	244,425	75,734	174,669	28,356	393,625	20,659	10,520	1,630	2,114,964
13-Feb	939,389	210,516	65,694	153,063	25,043	342,310	18,372	9,050	1,402	1,764,839
13-Mar	913,849	207,920	58,040	133,554	25,905	347,033	19,194	9,297	1,440	1,716,232
13-Apr	787,293	182,223	41,135	92,059	23,748	316,326	15,159	8,639	1,338	1,467,920
13-May	843,146	197,735	30,639	68,662	24,785	324,110	15,977	8,613	1,334	1,515,001
13-Jun	1,188,910	267,556	28,307	66,659	26,267	339,415	16,999	8,214	1,272	1,943,599
13-Jul	1,559,125	347,813	28,656	71,794	28,826	368,216	18,814	8,494	1,316	2,433,054
13-Aug	1,428,298	326,542	25,513	65,511	28,509	359,310	18,745	8,965	1,389	2,262,781
13-Sep	965,965	226,493	18,522	47,256	24,828	310,762	16,526	9,121	1,413	1,620,885
13-Oct	838,933	198,266	22,794	51,525	23,857	292,533	16,021	10,056	1,558	1,455,544
13-Nov	908,371	207,362	39,515	82,060	22,620	276,669	15,459	10,136	1,570	1,563,763
13-Dec	1,108,440	240,086	61,687	135,507	25,011	298,000	20,197	10,829	1,677	1,901,434
14-Jan	1,091,368	230,653	69,736	164,451	25,734	304,096	20,859	10,790	1,671	1,919,356
14-Feb	881,848	198,850	60,580	144,168	22,820	267,055	18,528	9,292	1,439	1,604,581
14-Mar	860,803	197,018	53,698	126,159	23,732	273,379	19,365	9,567	1,482	1,565,202
14-Apr	743,436	173,140	38,165	87,201	21,865	251,754	15,292	8,906	1,379	1,341,139
14-May	796,353	188,135	28,499	65,167	22,803	259,425	16,023	8,841	1,369	1,386,615
14-Jun	1,147,001	260,021	26,897	64,613	24,525	275,901	17,204	8,505	1,317	1,825,984
14-Jul	1,506,992	338,599	27,278	69,701	26,913	299,723	18,938	8,745	1,355	2,298,242
14-Aug	1,376,903	316,939	24,214	63,400	26,645	293,242	18,787	9,181	1,422	2,130,733
14-Sep	938,903	221,565	17,721	46,087	23,577	258,136	16,741	9,427	1,460	1,533,617
14-Oct	812,532	193,361	21,769	50,114	22,668	243,317	16,151	10,329	1,600	1,371,840
14-Nov	878,125	201,720	37,639	79,590	21,480	230,643	15,496	10,341	1,602	1,476,637
14-Dec	1,089,183	237,228	59,686	133,473	24,165	253,180	20,487	11,149	1,727	1,830,276
15-Jan	1,061,055	225,216	66,688	160,054	24,730	258,138	21,003	11,037	1,710	1,829,631
15-Feb	860,611	194,859	58,142	140,819	22,057	228,886	18,727	9,560	1,481	1,535,143
15-Mar	844,365	194,099	51,813	123,882	23,119	236,763	19,689	9,913	1,535	1,505,177
15-Apr	724,116	169,458	36,583	85,068	21,216	218,010	15,458	9,196	1,424	1,280,529
15-May	772,583	183,495	27,223	63,355	22,042	224,761	16,103	9,091	1,408	1,320,062

The monthly volumes presented above for the various rate classed are aggregated and set alongside the representative monthly Peak and Off-Peak Average Load in Table P below with the full 2012 to 2017 planning period presented in Attachment H.

TABLE P: AGGREGATED MONTHLY AND AVERAGE LOAD REQUIREMENTS FOR COMED (JUNE 2012 THROUGH MAY 2015)

Contract Month	Total Load (MWh)		Average Load (MW)	
	On-Peak	Off-Peak	On-Peak	Off-Peak
12-Jun	1,483,123	1,377,522	4,414	3,587
12-Jul	1,783,342	1,749,011	5,308	4,287
12-Aug	1,773,935	1,463,757	4,820	3,893
12-Sep	999,298	1,155,587	3,287	2,778
12-Oct	982,889	843,147	2,671	2,242
12-Nov	889,563	868,610	2,648	2,262
12-Dec	969,881	1,122,796	3,031	2,648
13-Jan	1,065,498	1,049,465	3,027	2,677
13-Feb	890,543	874,296	2,783	2,484
13-Mar	825,734	890,498	2,458	2,183
13-Apr	771,098	696,822	2,191	1,894
13-May	779,607	735,393	2,215	1,876
13-Jun	957,737	985,862	2,993	2,465
13-Jul	1,284,990	1,148,064	3,651	2,929
13-Aug	1,188,879	1,073,902	3,377	2,740
13-Sep	792,561	828,324	2,477	2,071
13-Oct	780,887	674,656	2,122	1,794
13-Nov	748,014	815,750	2,338	2,039
13-Dec	919,251	982,183	2,736	2,407
14-Jan	962,107	957,250	2,733	2,442
14-Feb	804,964	799,617	2,516	2,272
14-Mar	748,042	817,161	2,226	2,003
14-Apr	700,108	641,031	1,989	1,742
14-May	676,392	710,223	2,013	1,741
14-Jun	939,364	886,620	2,796	2,309
14-Jul	1,213,357	1,084,885	3,447	2,768
14-Aug	1,068,561	1,062,173	3,180	2,603
14-Sep	787,188	746,429	2,343	1,944
14-Oct	733,187	638,654	1,992	1,699
14-Nov	668,563	808,073	2,199	1,942
14-Dec	922,539	907,737	2,621	2,316
15-Jan	873,949	955,682	2,601	2,342
15-Feb	770,530	764,613	2,408	2,172
15-Mar	751,617	753,560	2,135	1,922
15-Apr	665,177	615,352	1,890	1,672
15-May	609,781	710,281	1,906	1,675

Energy required by the Eligible Retail Customers comes from four sources. First, the swap contract with ExGen provides a financial hedge on 3,000 MW of ATC energy during the June 2012 – May 2013 period. Second, certain fixed price physical supply contracts were secured through the 2011 procurement process. Third, the long-term renewable contracts that were entered into in December 2010 provide a financial hedge on 1,261,725 MWH a year for the period June 2012 through May 2032. Fourth, the IPA will solicit standard wholesale products through a sealed-bid RFP per this Plan. Fifth, balancing energy will be procured from the PJM-administered day-ahead and real-time energy markets.

In determining the granularity of the standard wholesale products to be procured through the RFP, the IPA recognized that if the products are defined in a way such that the megawatt amount contracted in each given hour is equal to the actual customer load in that hour, then the wholesale products will effectively provide price stability for customers because the fluctuations in the cost to supply the load will effectively be hedged. Yet, standard products traded in the wholesale market do not involve delivery quantities that vary within the twenty-four (24) monthly on-peak/off-peak periods throughout the year,[136] so the quantities of energy procured in the form of standard wholesale products cannot approximate customer load shapes on a more granular basis than a monthly on-peak/off-peak basis.

Given these facts, the IPA's procurement administrator will issue solicitations to lock-in fixed prices for fixed quantities of energy supply, using single-month, multi-month, and/or annual contracts for on-peak, off-peak, and/or around-the-clock blocks during the period between June 2012 and May 2015, in whatever combinations are deemed appropriate by the procurement administrator, given the objectives described in this plan. The target procurement quantities are determined by multiplying ComEd's average forecasted load obligation in each monthly on-peak/off-peak period by the targeted hedge position after the procurement event is completed (i.e. 35% for requirements two years out, 70% for requirements one year out, and 100% for requirements in the year in which power is delivered). Next, MWs covered by previous RFPs and the ExGen swap are subtracted from the target requirements. To the extent the calculated procurement quantity for a period is less than zero, no energy will be procured for that period and existing positions will be maintained. Also note that calculations in the model are rounded to the nearest 50 MW. By procuring a portfolio of the most granular standard wholesale products available in quantities reflective of forecasted loads, the forecasted net amount of energy transacted in the volatile spot market will be minimized.

Bidders will be provided an opportunity to bundle their bids for various products. By providing some flexibility for bundled bids, bidders will be better able to bid on the products for which they can offer the most competitive prices. The procurement administrator will accept the bids that together represent the lowest cost portfolio of products that provide the desired monthly on-peak and off-peak quantities being solicited through the RFP.

Based on the current load forecast, the quantities of standard wholesale energy products to be procured through the sealed-bid RFP are as follows (rounded to the nearest 50 MW) are found in Tables Q and R. A full schedule of related planned procurement loads for ComEd can be found in Attachments I and J.

TABLE Q: PROPOSED COMED OFF-PEAK LOAD VOLUMES TO SECURE IN 2012 CYCLE (JUNE 2012 THROUGH MAY 2015)

Contract Month	Off-Peak Contract Volumes to Secure (MW)					
	Projected Volume (MW)	Swap Volumes (MW)	2011 IPA Procurement (MW)	Long-Term Renewable Energy (MW)	Residual Volumes (MW)	2012 IPA Procurement (MW)
12-Jun	3,587	3,000	-	106	481	500
12-Jul	4,287	3,000	600	80	607	600
12-Aug	3,893	3,000	300	109	484	500
12-Sep	2,778	3,000	-	97	-319	0
12-Oct	2,242	3,000	-	180	-938	0
12-Nov	2,262	3,000	-	204	-942	0
12-Dec	2,648	3,000	-	140	-492	0
13-Jan	2,677	3,000	-	180	-503	0

[136] Both the NYMEX and the Intercontinental Exchange, Inc. ("ICE"), the two most visible platforms on which to trade electricity products, report prices for products with delivery periods that are no more granular than by monthly on-peak/off-peak period.

13-Feb	2,484	3,000	-	167	-683	0
13-Mar	2,183	3,000	-	194	-1,011	0
13-Apr	1,894	3,000	-	205	-1,311	0
13-May	1,876	3,000	-	168	-1,292	0
13-Jun	2,465	-	1,250	102	1,113	350
13-Jul	2,929	-	1,800	83	1,046	150
13-Aug	2,740	-	1,650	105	985	150
13-Sep	2,071	-	1,050	101	920	300
13-Oct	1,794	-	1,100	180	514	0
13-Nov	2,039	-	1,250	196	593	0
13-Dec	2,407	-	1,250	146	1,011	300
14-Jan	2,442	-	1,300	180	962	250
14-Feb	2,272	-	1,400	167	705	0
14-Mar	2,003	-	1,250	194	559	0
14-Apr	1,742	-	1,100	205	437	0
14-May	1,741	-	1,100	162	479	0
14-Jun	2,309	-	-	106	2,203	700
14-Jul	2,768	-	-	83	2,685	900
14-Aug	2,603	-	-	101	2,502	800
14-Sep	1,944	-	-	105	1,839	600
14-Oct	1,699	-	-	180	1,519	400
14-Nov	1,942	-	-	188	1,754	500
14-Dec	2,316	-	-	152	2,164	650
15-Jan	2,342	-	-	173	2,169	650
15-Feb	2,172	-	-	167	2,005	600
15-Mar	1,922	-	-	202	1,720	450
15-Apr	1,672	-	-	205	1,467	400
15-May	1,675	-	-	156	1,519	450

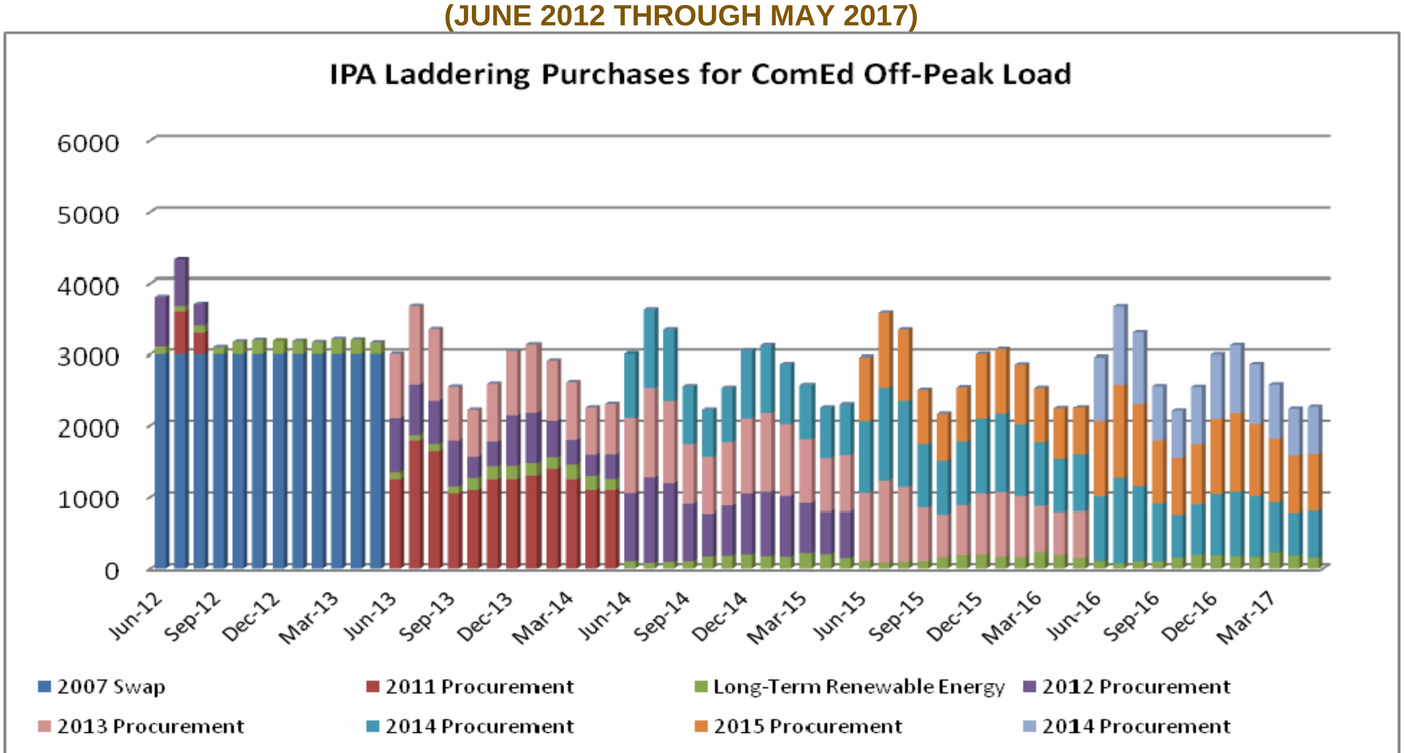
TABLE R: PROPOSED COMEDPEAK LOAD VOLUMES TO SECURE IN 2012 CYCLE (JUNE 2012 THROUGH MAY 2015)

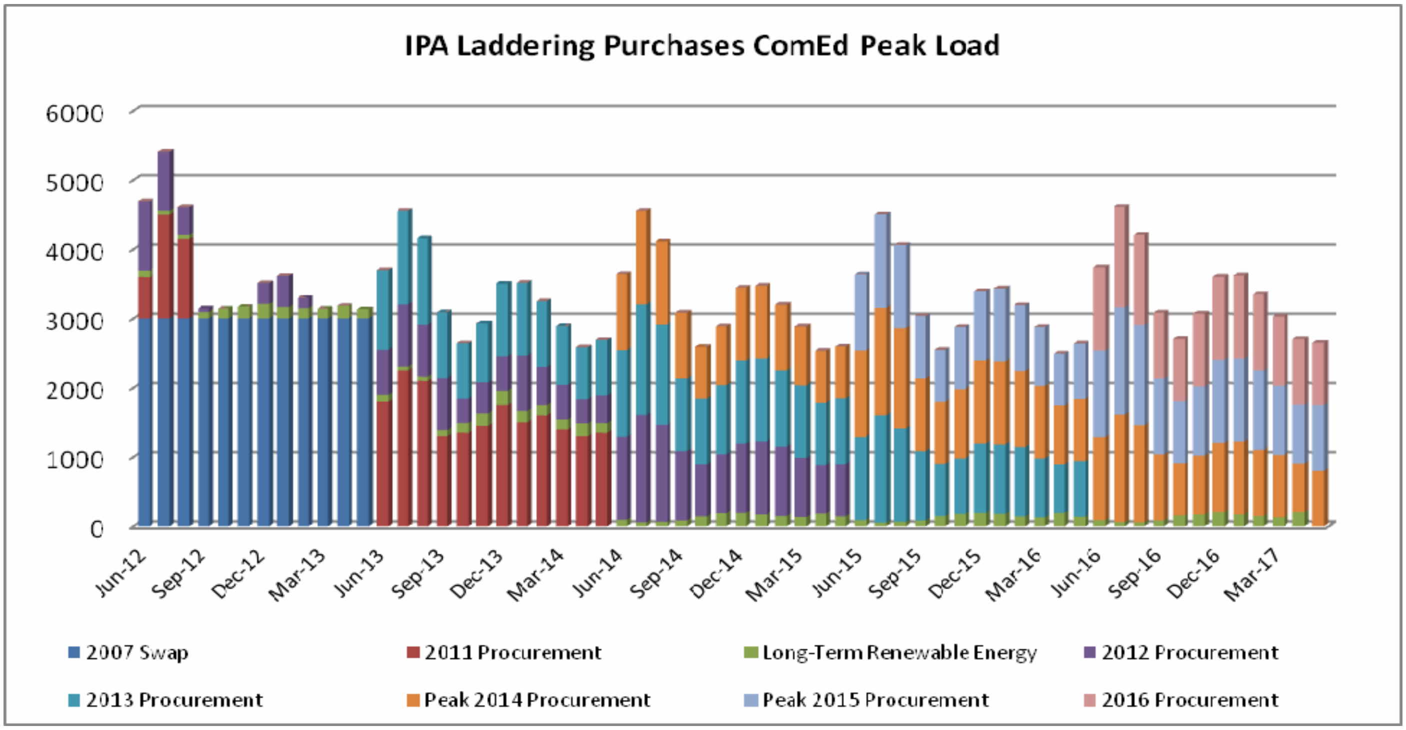
Contract Month	Peak Contract Volumes to Secure (MW)					
	Projected Volume (MW)	Swap Volumes (MW)	2011 IPA Procurement (MW)	Long-Term Renewable Energy (MW)	Residual Volumes (MW)	2012 IPA Procurement (MW)
12-Jun	4,414	3,000	600	94	720	700
12-Jul	5,308	3,000	1,500	61	747	750
12-Aug	4,820	3,000	1,150	61	609	600
12-Sep	3,287	3,000		97	190	200
12-Oct	2,671	3,000		150	-479	0
12-Nov	2,648	3,000		178	-530	0
12-Dec	3,031	3,000		162	-131	0
13-Jan	3,027	3,000		164	-137	0
13-Feb	2,783	3,000		152	-369	0
13-Mar	2,458	3,000		174	-716	0
13-Apr	2,191	3,000		188	-997	0
13-May	2,215	3,000		187	-972	0

13-Jun	2,993	-	1,800	99	1,094	200
13-Jul	3,651	-	2,250	59	1,342	250
13-Aug	3,377	-	2,100	63	1,214	200
13-Sep	2,477	-	1,300	92	1,085	350
13-Oct	2,122	-	1,350	150	622	0
13-Nov	2,338	-	1,450	187	701	0
13-Dec	2,736	-	1,750	155	831	0
14-Jan	2,733	-	1,500	164	1,069	250
14-Feb	2,516	-	1,600	152	764	0
14-Mar	2,226	-	1,400	174	652	0
14-Apr	1,989	-	1,300	188	501	0
14-May	2,013	-	1,350	196	467	0
14-Jun	2,796	-	-	94	2,702	900
14-Jul	3,447	-	-	59	3,388	1150
14-Aug	3,180	-	-	66	3,114	1050
14-Sep	2,343	-	-	87	2,256	750
14-Oct	1,992	-	-	150	1,842	550
14-Nov	2,199	-	-	197	2,002	550
14-Dec	2,621	-	-	148	2,473	750
15-Jan	2,601	-	-	172	2,429	750
15-Feb	2,408	-	-	152	2,256	700
15-Mar	2,135	-	-	166	1,969	600
15-Apr	1,890	-	-	188	1,702	450
15-May	1,906	-	-	206	1,700	450

Graphs 4 and 5 represent how the Plan anticipates securing load for Eligible Retail Customers by laddering in purchases so that no one month or season is purchased all at one time.

GRAPH 4: PROPOSED LADDERING SCHEDULE FOR COMED OFF-PEAK LOAD (JUNE 2012 THROUGH MAY 2017)





The PUA provides that it is the duty of the Procurement Administrator, in consultation with the Commission, ComEd, and other interested parties, to develop the standard contract form that will be used for the standard wholesale products to be procured through the RFP.[137]

The standard wholesale products to be procured through the RFP could be settled physically or financially. In both cases, ComEd would contract to purchase or hedge specific quantities of energy at fixed prices.

In the case of financial settlement, ComEd would procure energy in the day-ahead or real-time markets and debit or credit a dollar amount to the seller based on the difference between the agreed-upon fixed contract price and an index price, whereby the index price would be specified in the contract to be either the day-ahead or real-time energy price. Financial contracts are generally referred to as “contracts for differences” (“CFD”). The swap contract with ExGen is an example of a financially settled contract.

In the case of physical settlement, the contracting parties would transact through PJM. In this case, both parties must be PJM members in good standing. ComEd and the seller would execute an agreement, under which the seller transfers energy to ComEd via a PJM eSchedule. ComEd would then directly pay the seller the agreed-upon fixed contract price for the specified amount of energy.

The choice between settling physically and financially does not affect service reliability. Whether the products settle physically or financially, PJM will still dispatch the system in such a way to ensure that customers' requirements are met. The decision to settle physically or financially affects the logistics regarding cash flows, the administrative tasks that are required of the various parties involved, the non-performance risks and the standard of legal review.

The IPA recommends that the contracts to be procured through the RFP be settled physically for ComEd volumes for the following reasons:

- Physical contracts are lower risk in the event of supplier default. The exposure of a supplier under a CFD is limited only by the PJM energy price cap of $999 per MWh. While it would be very rare for prices for a sustained period to be at or near the energy price cap, a primary value of a hedge is to protect against such occurrences. It is not inconceivable that a supplier may in fact be unable to pay the difference between spot and contract prices if there is a sustained price spike. If the contract is physical, the

[137] 220 ILCS 5/16 – 111.5(c)(1)(v); 220 ILCS 5/16-111.5(e)(2).

supplier will be liable to PJM, and until the supplier's PJM market privileges are revoked, ComEd will receive the energy at the contract price. Default costs would be spread over PJM.

In the event of a default under a CFD, ComEd would owe PJM the high spot prices and would bear the cost of the supplier being unable to pay the difference. While increased collateral may reduce this risk, it is not clear that there are adequate credit provisions to equalize this risk; therefore the physical contract is lower risk for customers.

- Physical contracts reduce ComEd credit requirements and overall credit costs. Under a financial contract, ComEd would be considered by PJM to be buying all loads in the spot market and would have to provide credit for all volumes. Under a physical contract, the supplier is responsible to provide credit for all volumes. While the credit cost is not eliminated it may be reduced as some suppliers may have lower financing costs, especially in the event that the supplier is maintaining offsetting long positions within PJM.

While the IPA recommended the procurement of Energy Efficiency as Alternative Resource ("EEAR"), the Commission did not approve it for inclusion in this Plan. The IPA may recommend future consideration of the purchase of EEAR for the ComEd portfolio. The purpose of this is twofold – first, to establish whether energy efficiency can be cost competitive with more traditional resources; and second, to establish additional benefits such as price stability can be gained through the expansion in the type of resource products placed into the ComEd portfolio.

Additional elements to the supply resources plan include:

Load Balancing Procedures. Upon Commission approval of the Final Plan, ComEd will utilize the PJM-administered day-ahead and real-time energy markets to balance its loads. On a daily basis, ComEd will report to PJM its estimate of its total load requirements for the following day. ComEd will then submit its day-after estimate to PJM via a daily load responsibility schedule and the estimate will in turn be settled by PJM based on the real time market prices.

If the delivered physical power exceeds the day-ahead estimate, PJM will credit the difference to ComEd at the day-ahead price; if the delivered physical power is less than the day-ahead estimate, PJM will charge ComEd the difference at the day-ahead price.

When ComEd submits its day-after estimate to PJM, PJM will perform a similar settlement function in the PJM real-time market. To the extent the day-ahead estimate reported by ComEd is less than the day-after estimate; PJM will charge ComEd the difference at the real-time price. To the extent that the day-ahead estimate reported by ComEd is greater than the day-after estimate, PJM will credit ComEd with the difference at the real-time price.

Portfolio Rebalancing in the Event of Significant Shifts in Load. The PUA requires that the IPA provide the criteria for portfolio rebalancing in the event of significant shifts in load. Over In large measure, the portfolio is automatically rebalanced on an annual basis, as shifts in load are incorporated into the utility-prepared forecasts used in the IPA's plans. However, the IPA recognizes that between the time that each plan's forecasts are prepared and the time that the relevant portion of the plan is implemented, the conditions underlying those forecasts can and do change. Thus, between March 1 and March 10, the IPA recommends that ComEd submit to the IPA and to Commission staff a revised base-case forecast of monthly on-peak and off-peak loads encompassing the first three years of the five-year planning horizon. Since a significant driver of load shifting is customer switching to alternative retail electric suppliers and, more recently, to municipal aggregation programs, the IPA recommends that Ameren pay particular attention to these factors. It is also recommended that ComEd survey the actual number and size of the municipalities that have at that time filed with the relevant election authority to hold, or have already passed referenda, approving "opt out" aggregation. Based on the information provided by ComEd, the IPA will work with ComEd, the Commission staff and the procurement administrator and monitor to revise the volumes of products that will be sought through the spring procurement events, but only if a consensus is reached.

Contingency Procurement Plan. The following is the plan to procure power and energy for ComEd's "Eligible Retail Customer" load should all or any part of that load not be met due to the advent of: 1) supplier default; 2) insufficient supplier participation; 3) Commission rejection of procurement results; or 4) any other cause. The plan is based on the contingency plan as specified in the IPA Act and Section 16-111.5(e)(5)(i) of the PUA.

Supplier Default. In the event of a supplier default that results in contract termination where the amount of load provided by that supplier is 200 MW or greater and there are more than 60 calendar days remaining on the defaulted contract term, ComEd will immediately notify the IPA, ICC Staff and the procurement administrator that another procurement event must be administered. The procurement administrator will execute a procurement event to replace the same products and amounts as that initially approved by the ICC in this plan. The ICC Staff and its procurement monitor will oversee the event. The replacement plan will, to the maximum degree possible, seek to replace the defaulted products with the same or similar products to those that were defaulted on. This substitute plan would continue to seek energy-only standard-block products. All ancillaries, capacity and load balancing requirements will continue to be procured through the PJM-administered markets. During the interim time period beginning at time of default and continuing through the contingency procurement process, all electric power and energy will be procured by the utility through PJM-administered markets. Notwithstanding, if a particular required product is not available through PJM, it shall be purchased in the wholesale market.

In the event of a supplier default that results in contract termination where the amount of load provided by that supplier is less than 200 MW or there are less than 60 calendar days remaining on the defaulted contract term, ComEd will procure the required power and energy directly from the PJM administered markets. This procurement would include day ahead and/or real time energy, capacity, and ancillary services. Should a required product not be available directly through the PJM administered markets, it shall be procured through the wholesale markets.

ICC Rejection of Initial Procurement Results or Insufficient Supplier Participation. In the advent that the ICC rejects the results of the initial procurement event or the initial procurement event results in under subscription, a meeting of the procurement administrator, the procurement monitor, and the ICC Staff shall occur within ten (10) calendar days to assess the potential causes and to consider what remedies, if any, could be put in place to either address the ICC's concerns or would result in full subscription to the load. If revisions to the procurement event are identified that would likely either address the ICC's concerns or enhance the possibility of having a fully subscribed load, the procurement administrator will implement those changes and run a procurement event predicated on a schedule established within the aforementioned meeting. The new procurement event will be executed by the procurement administrator within ninety (90) calendar days of the date that the initial procurement process is deemed to have failed.

Should a procurement event be required subsequent to the initial event, the procurement administrator and the procurement monitor will separately submit a confidential report to the ICC within 2 business days after opening the sealed bids. The procurement administrator's report will put forth a recommendation for acceptance or rejection of bids based on the established benchmarks, as well as other observed factors, to include any modifications necessary to run a subsequent procurement event if necessary.

Other scenarios. In all cases where the factors are such that, either for an interim period or otherwise, there would be insufficient power and energy to serve the required load, ComEd will procure the required power and energy requirements for the eligible load through the PJM-administered markets. Direct procurement activities would thus include day-ahead and/or real-time energy, along with the normal direct procurement of capacity and ancillary services. Also, in the case that a particular required product is not available through PJM, ComEd will purchase that product through the wholesale market.

3.2 Capacity Resources.

Special challenges as associated with meeting the capacity requirements of the Utilities. Capacity resources must be secured to support wholesale supply contracts entered into by the Utilities.

TABLE S: OVERVIEW OF KEY CAPACITY RESOURCE ISSUES

Key Capacity Resource Issues	
Ameren Illinois Company	Commonwealth Edison
▪ Capacity markets are bilateral ▪ MISO has proposed a forward capacity market ▪ MISO capacity market proposal may be litigated ▪ **Existing Demand Response (DR) programs do not appear to be in operation.**	▪ Capacity markets are centralized within PJM ▪ PJM RPM process provides 3-year forward curve ▪ Capacity costs rise through 2012, 2013, and 2014 ▪ **Existing Demand Response (DR) programs appear to reduce IPA portfolio capacity requirements.**

TABLE T: OVERVIEW OF PRIMARY PLAN INCLUSIONS FOR CAPACITY RESOURCES

Primary Capacity Resource Measures	
Ameren Illinois Company	Commonwealth Edison
▪ IPA secure capacity through direct solicitation ▪ Secure monthly and one-year capacity requirements ▪ Do not reduce capacity procurement volumes by projected DR program performance.	▪ Utility secure capacity via the PJM RPM offering ▪ Secure capacity requirements as necessary ▪ Reduce capacity procurement volumes by projected DR program

3.2.1 Background. Ameren and ComEd acquire capacity resources to meet ISO requirements tied to reliability.

3.2.2 Evaluation. Ameren and ComEd are obligated by the MISO and PJM Tariffs to secure specific capacity resource volumes. PJM has created and maintains a forward market to set prices for capacity; securing capacity resources for ComEd load via this market tool is a means by which the resources can be secured at a competitive rate. MISO operates primarily on a bi-lateral contracting basis; the only option for Ameren to purchase more than prompt month capacity is to conduct a procurement event.

3.2.3 Recommendations. The IPA recommends the following measures with regard to Ameren and ComEd transmission arrangements:

3.2.3.1 Ameren Illinois Company. Module E of the Midwest ISO's Open Access Transmission, Energy and Operating Reserve Markets Tariff addresses resource adequacy. Module E requires Ameren to hold the lower of the reserve requirement as specified by an annual planning process undertaken by the Midwest ISO or the requirement of the relevant state regulatory authority. Module E, along with the associated business practice manual, also requires Ameren to provide an annual forecast of monthly loads adjusted for transmission losses and subsequently confirm on a month-ahead basis that Ameren has enough Planning Reserve Credits to meet or exceed its Resource Adequacy Requirement (the monthly peak load forecast plus its planning reserve margin).

In 2009, MISO implemented significant penalties associated with a capacity deficiency event based on the Cost of New Entry (CONE). For the 2009 Planning Year, the deficiency penalty was determined by MISO to be $80/kW-Month, $90/kW-Month for 2010 and $95/kW-Month for 2011.

The IPA makes note that significant changes to the MISO resource adequacy construct are currently filed at FERC. Initially planned to be filed in December of 2010, MISO ultimately filed tariff modifications and enhancements to Module E on July 20, 2011. These enhancements include moving to an annual forward construct and thus moving away from the current monthly construct. The new modifications also address zonal delivery and pricing concepts. MISO has requested FERC order an effective date of October 1, 2012 and has requested an order from FERC no later than February 29, 2012 which will be after the Commission order relative to this Plan.

For the planning year 2012, MISO will utilize its existing tariff which is based on monthly resource requirements. The IPA will therefore procure 100% of the Capacity required to fully comply with the MISO resource adequacy requirements for the 2012 planning year with such quantities based on monthly requirements. For planning years 2013 and 2014, the IPA proposes to procure 50% and 35% respectively of the annual Capacity based on MISO's anticipated change to an annual forward construct. The IPA notes that FERC has not ordered on the MISO proposal and it's possible that the MISO proposal may be modified or rejected outright. As a solution, the IPA proposes that the Commission approve the IPA proposal to pursue annual Capacity for 2013 and 2014. But the IPA also asks that the Commission acknowledge the dynamic nature of the MISO proposal and therefore authorize the IPA to make modifications to this plan as warranted during the 2012 procurement process after consultation with the Procurement Administrator, Procurement Monitor, ICC Staff and Ameren Illinois.

TABLE U: PROPOSED AMEREN CAPACITY CONTRACT VOLUMES TO SECURE IN 2012 CYCLE (JUNE 2012 THROUGH MAY 2013)

AMEREN CAPACITY CONTRACT VALUES - MONTHLY (June 2012 - May 2013)									
	Peak Load	Transmission Losses	Planning Reserves	Capacity Requirement	2009 Purchases	2010 Purchases	2011 Purchases	2012 Purchases	% Hedged
June-12	3,568	80	138	3,787	0	1,440	0	2,350	100%
July-12	4,008	90	155	4,253	0	1,570	0	2,690	100%
August-12	4,042	91	157	4,289	0	1,530	0	2,760	100%
September-12	3,454	78	134	3,665	0	1,410	0	2,260	100%
October-12	2,412	54	93	2,560	0	920	0	1,640	100%
November-12	2,234	50	87	2,370	0	900	0	1,470	100%
December-12	2,677	60	104	2,841	0	1,200	0	1,650	100%
January-13	2,835	64	110	3,008	0	1,180	0	1,830	100%
February-13	2,597	58	101	2,756	0	1,080	0	1,680	100%
March-13	2,140	48	83	2,271	0	950	0	1,330	100%
April-13	1,979	45	77	2,100	0	810	0	1,290	100%
May-13	2,513	57	97	2,667	0	940	0	1,730	100%

Please note that MISO changed its planning reserve margin for 2012 plan year from 3.81% to 3.79% and the above values reflect this small change.The IPA proposes undertaking capacity procurement into future years during the 2012 procurement cycle. This will result in a hedge of approximately 50% of the capacity requirement for the 2013 planning year (June 2013 through May 2014), and 35% of the capacity requirement for the 2014 planning year (June 2014 through May 2015) as detailed in Table V:

TABLE V: PROPOSED AMEREN CAPACITY CONTRACT VOLUMES TO SECURE IN 2012 CYCLE (JUNE 2013 THROUGH MAY 2015)

AMEREN CAPACITY CONTRACT VALUES - ANNUAL (June 2013 - May 2017)									
	Peak Load	Transmission Losses	Planning Reserves	Capacity Requirement	2009 Purchases	2010 Purchases	2011 Purchases	2012 Purchases	% Hedged
June-13	3,523	79	137	3,739	0	0	0	2,130	50%
July-13	3,944	89	153	4,186	0	0	0		
August-13	3,997	90	155	4,242	0	0	0		
September-13	3,406	77	132	3,615	0	0	0		
October-13	2,394	54	93	2,540	0	0	0		
November-13	2,237	50	87	2,374	0	0	0		
December-13	2,668	60	103	2,831	0	0	0		
January-14	2,812	63	109	2,985	0	0	0		
February-14	2,590	58	100	2,749	0	0	0		
March-14	2,128	48	82	2,258	0	0	0		
April-14	1,961	44	76	2,081	0	0	0		
May-14	2,450	55	95	2,600	0	0	0		
June-14	3,383	76	131	3,590	0	0	0	1,440	35%
July-14	3,803	86	147	4,036	0	0	0		
August-14	3,869	87	150	4,106	0	0	0		
September-14	3,290	74	127	3,491	0	0	0		
October-14	2,288	51	89	2,428	0	0	0		
November-14	2,143	48	83	2,274	0	0	0		
December-14	2,573	58	100	2,730	0	0	0		
January-15	2,697	61	105	2,862	0	0	0		
February-15	2,479	56	96	2,631	0	0	0		
March-15	2,038	46	79	2,163	0	0	0		
April-15	1,885	42	73	2,000	0	0	0		
May-15	2,419	54	94	2,567	0	0	0		
June-15	3,313	75	128	3,516	0	0	0	0	0%
July-15	3,745	84	145	3,975	0	0	0		
August-15	3,805	86	147	4,038	0	0	0		
September-15	3,232	73	125	3,430	0	0	0		
October-15	2,249	51	87	2,386	0	0	0		
November-15	2,095	47	81	2,223	0	0	0		
December-15	2,515	57	97	2,669	0	0	0		
January-16	2,679	60	104	2,843	0	0	0		

February-16	2,491	56	97	2,644	0	0	0		
March-16	2,013	45	78	2,136	0	0	0		
April-16	1,867	42	72	1,982	0	0	0		
May-16	2,388	54	93	2,535	0	0	0		
June-16	3,295	74	128	3,496	0	0	0	0	0%
July-16	3,729	84	144	3,957	0	0	0		
August-16	3,772	85	146	4,003	0	0	0		
September-16	3,206	72	124	3,402	0	0	0		
October-16	2,234	50	87	2,371	0	0	0		
November-16	2,072	47	80	2,199	0	0	0		
December-16	2,496	56	97	2,649	0	0	0		
January-17	2,647	60	103	2,809	0	0	0		
February-17	2,427	55	94	2,575	0	0	0		
March-17	1,994	45	77	2,116	0	0	0		
April-17	1,850	42	72	1,964	0	0	0		
May-17	2,372	53	92	2,518	0	0	0		

3.2.3.2 Commonwealth Edison. ComEd will continue to procure the capacity and ancillary services required by the Eligible Retail Customers directly from PJM-administered markets. Under the RPM program approved by the FERC and administered by PJM, ComEd is able to purchase capacity directly from PJM-administered markets. The RPM capacity prices for the June 2012 - May 2015 period have already been determined through a competitive bid process administered by PJM, so direct procurement from PJM results in a reasonable approach to procuring capacity for these customers. Furthermore, the PJM-administered markets for ancillary services are the most visible and easily accessible markets for these services so direct procurement from these markets is a reasonable approach for providing these services to customers.

From time to time, PJM may determine that the amount of capacity it procured three years prior to the delivery year exceeds the amount actually needed in the delivery year when adjusted for updated load forecasts. In such cases, PJM may return excess capacity credits to the utility. These credits represent MW units of capacity and are not in the form of cash or cash equivalents. While these credits cannot be used to offset capacity payments to PJM, they can be used by the utility to offset shortfalls in capacity the utility previously bid and which cleared in the applicable RPM auction or they can be sold to a third party. To the extent practicable, the IPA proposes that ComEd attempt to sell any excess capacity credits it does not need and return any corresponding proceeds to customers. PJM has a bulletin board where such excess capacity credits can be made available for sale.

3.3 Renewable Energy Resources.

Special challenges are associated with meeting the Illinois Renewable Portfolio Standard. Tables R and S below outline those challenges and the general procurement approaches the IPA recommends for use in satisfying the RPS goal.

TABLE W: OVERVIEW OF KEY RENEWABLE ENERGY RESOURCE ISSUES

Key Renewable Energy Resource Issues
Ameren Illinois Company and Commonwealth Edison
▪ The Renewable Portfolio Standard (RPS) may be met by securing Renewable Energy Credits (RECs) or RECs plus the associated power outputs. ▪ The RPS must be satisfied with a 75% carve-out for wind power, and an eventual 6% carve-out for solar. ▪ In the current market, wind RECs demand a very low price while solar RECs carry a very high price. ▪ The annual Renewable Resources Budget (RRB) establishes a cap that prevents the RPS from increasing consumer costs by more than 2.015% ▪ The annual RRB is expected to decline over time as the total IPA portfolio volumes decline ▪ About 1.9 million RECs of variable costs to be delivered to Utilities between June 2012 and May 2033 from long-term contracts. ▪ **Commitments to purchase Renewable Energy Resources <u>cannot</u> exceed the annual RRB**

TABLE X: OVERVIEW OF PRIMARY RENEWABLE ENERGY RESOURCE MEASURES

Primary Renewable Energy Resource Measures
Ameren Illinois Company and Commonwealth Edison
▪ Project conservative annual Renewable Resources Budget (RRB) for the next year ▪ ▪ Sort bids according to price and source (solar, wind, etc.) ▪ Select bids in a manner that yields at least the minimum carve out requirements are met when the LTPPA volume are added to the new REC volumes.

3.3.1 Background. Section 1-75(c) of the IPA Act establishes that:

> *The procurement plans shall include cost-effective renewable energy resources. A minimum percentage of each utility's total supply to serve the load of eligible retail customers, as defined in Section 16-111.5(a) of the Public Utilities Act*[138]

The statute defines renewable energy resources as follows:

> *"Renewable energy resources" includes energy and its associated renewable energy credit or renewable energy credits from wind, solar thermal energy, photovoltaic cells and panels, biodiesel, anaerobic digestion, crops and untreated and unadulterated organic waste biomass, tree waste, hydropower that does not involve new construction or significant expansion of hydropower dams, and other alternative sources of environmentally preferable energy. For purposes of this Act, landfill gas produced in the State is considered a renewable energy resource.*[139]

The statute also applies a cost cap to the process where the cost of compliance must not exceed a formula rate. The annual volume and cost cap standards are presented in the following table:

TABLE Y: RPS STANDARDS FOR AMEREN AND COMED

Delivery period	Minimum Percentage (Annual volume goal)	Maximum Cost Standard
2012-2013	7% of June 1, 2010 through May 31, 2011 eligible retail customer load	No more than the greater of 2.015% of the amount paid per kilowatt hour by those customers during the year ending May 31, 2007 or the incremental amount per kilowatt hour paid for these resources in 2011
2013-2014	8% of June 1, 2011 through May 31, 2012 eligible retail customer load	No more than the greater of 2.015% of the amount paid per kilowatt hour by those customers during the year ending May 31, 2007 or the incremental amount per kilowatt hour paid for these resources in 2011
2014-2015	9% of June 1, 2011 through May 31, 2012 eligible retail customer load	No more than the greater of 2.015% of the amount paid per kilowatt hour by those customers during the year ending May 31, 2007 or the incremental amount per kilowatt hour paid for these resources in 2011
2015-2016	10% of June 1, 2011 through May 31, 2012 eligible retail customer load	No more than the greater of 2.015% of the amount paid per kilowatt hour by those customers during the year ending May 31, 2007 or the incremental amount per kilowatt hour paid for these resources in 2011
2016-2017	11.5% of June 1, 2011 through May 31, 2012 eligible retail customer load	No more than the greater of 2.015% of the amount paid per kilowatt hour by those customers during the year ending May 31, 2007 or the incremental amount per kilowatt hour paid for these resources in 2011

It is important to note that the volume goals and cost caps for the IPA are variable. As retail competition develops in Illinois, the IPA expects that the RPS volume goals as the available budgets will diminish over time.

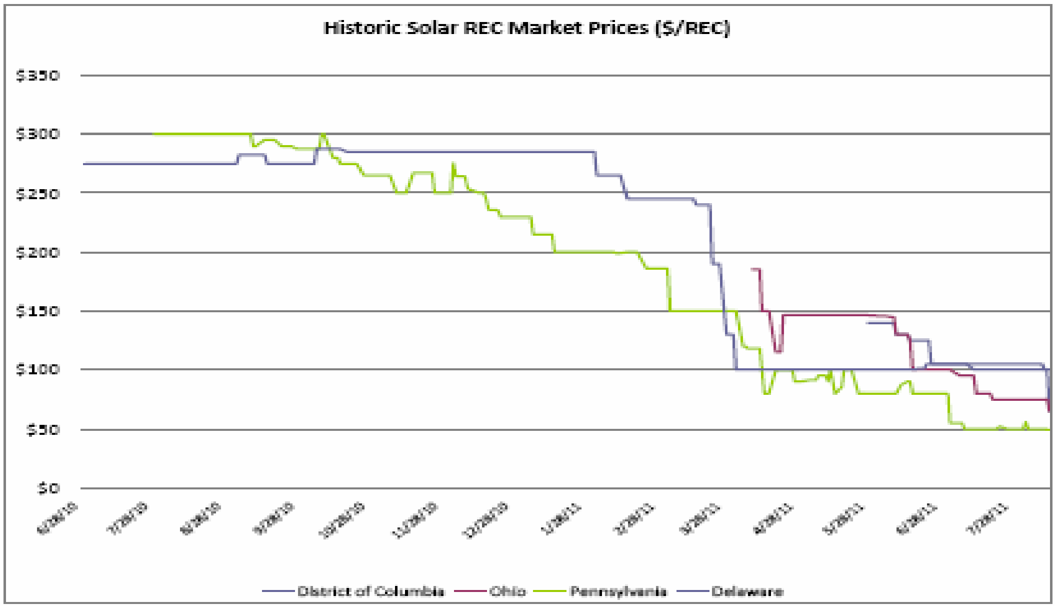
In prior years, the RPS obligation was met through the purchase of RECs only. This approach proved sufficient to meet RPS volume goals while observing the statutory budget constraints. In December 2010, a series of 20-year Long-Term Power Purchase Agreements (LTPPA) were entered. The LTPPAs specified a bundled purchase of energy plus RECs from renewable resources.

[138] 20 ILCS 3855/1-75(c)(1)
[139] 20 ILCS 3855/1-10.

Under these contracts, a single price was set for the bundled product (energy plus REC) with a 2% per annum cost escalator over the term of the contracts. The cost of the energy included in the product was to be paid as a standard index energy contract, with the unit price set at variable market index. The cost of the REC was to be paid out of the Renewable Resources Budget (RRB), with the unit price set at the contract cost minus the variable market index energy cost.

Lastly, the IPA Act requires that 75% of the RPS be met with wind resources and eventually 6% by solar resources. Recent solicitations for short term wind RECs within the region indicate that market prices for those assets range around $1/REC. Solar RECs are less plentiful and thus more expensive than wind RECs; however, the costs of solar RECs in other states appear to be dropping. Graph 6 presents historical price data for solar RECS dating back to June of 2010:

GRAPH 6: HISTORIC SOLAR REC COSTS



3.3.2 Evaluation. Meeting the RPS obligation is growing more complicated over time with volume requirements, budgets, and the costs of pre-existing contract obligations all operating in a variable manner. Additionally, because the forward cost curve governing the applied costs for RECs delivered under the LTPPAs is confidential, a final RRB for each utility cannot be presented in this Plan.

The confidential forward price curve for energy is a critical component to establishing annual Renewable Resource Budgets developed by the IPA, Procurement Administrators, Commission Staff, and the Procurement Monitor to aid in establish which portion of the annual RRB is to be allocated to the LTPPA contract costs. Therefore, the cost of the long-term obligations is not a known variable and is subject to change over time.

For the purposes of this Plan, the IPA observes that a comprehensive procurement system for renewable is necessary. The presence of the competing solar and wind carve-outs and their wide cost differences coupled with revenue variance increases the risk of the IPA portfolio not meeting its procurement goals in future years.

3.3.3 Recommendations. The ultimate limit on the procurement of renewable energy resources is the Renewable Resources Budget. The IPA will use the following method to meet the RPS obligations for the 2012-2013 compliance year:

- Conduct procurements that yield carve-out consistent one year contracts for solar and wind RECs
  - In 2012, invite bids for one year unbundled RECs
  - Select only those bids such that all renewable contract volumes fit beneath the factored NRBB
  - Sort bids according to price and source (solar, wind, etc.)
  - Select the lowest bid combination that yields at least the minimum carve out requirements when the LTPPA volumes are added to the new REC volumes.

o

The proposed approach would facilitate offers from short term REC bidders seeking contracts for low price RECs.

In addition to the above, the IPA recommended the following in its proposed Plan:

- **Distributed SRECs.** The IPA shall design the procurement program for distributed SRECs between January - May 2012, announce the program in June 2012 and initiate the first procurement event by December 2012. The procurement program will be designed to enable the Utilities to sign long-term (at least 10-year) contracts for SRECs from distributed solar systems in Illinois at prices that are competitive with the average SREC clearing price from the procurement process described above. The IPA will consider the following broad program types:

  (1) A fixed price, long-term, standard offer contract program in which initial contract prices are based on the auction clearing prices for SRECs from the IPA's Spring 2012 auction, and contract price offers are adjusted over time to track the market;
  (2) An auction for long-term SREC contracts in which participation is limited to aggregators of SRECs from multiple small and mid-size distributed solar systems in Illinois.

  In order to design and announce the distributed SREC procurement program by June 2012 and initiate the first procurement event by December 2012, the IPA will host a series of workshops between January - May 2012. IPA will invite input from the public, including policy experts and solar industry stakeholders to address major program design features and other issues, including:

  - Definitions for "small" and "mid-size" distributed solar systems eligible to participate in the procurement.
  - The terms and conditions under which distributed SREC providers would verify SREC deliveries
  - Administrative procedures that minimize transaction costs for participants and administrative burdens for the utilities and the IPA
  - A process for assessing program results, including the energy and capacity values of the distributed solar energy developed as a result of the program, and the benefits to the Illinois distribution grid.
  - A process for modifying the program over time.

  For purposes of this Plan, "distributed SREC" is intended to mean the renewable energy credit associated with the output of a solar PV system interconnected to the electric distribution system in Illinois and located on the customer's side of the electric meter.

After due consideration, the IPA has withdrawn this recommendation, and will not be procuring Distributed SRECs for the 2012 Plan Cycle.

Pricing Benchmark. The Procurement Administrators will be directed to continue to establish benchmark REC prices for the 2012 procurement event, and to reject bids priced above the benchmarks. The benchmarks shall be set at levels that consider relevant market prices. The benchmark prices shall be confidential, but shall be provided to, and will be subject to, Commission review and approval prior to solicitations of REC bids.

Preferences. Section 1-75 (c) (3) of the IPA Act requires that until June 1, 2011 cost effective renewable energy resources be procured first from facilities in the State of Illinois, then from facilities located in states adjacent to Illinois, then from facilities located elsewhere. Because renewable energy resources are being procured for a period after June 1, 2011, the State of Illinois preference no longer applies.

Compliance Tracking. PJM Environmental Information System's ("EIS") Generation Attribute Tracking System ("GATS"), the Midwest Renewable Energy Tracking System ("M-RETS") and the North American Renewables Registry ("NAR") will be utilized to independently verify the location of generation, resource type and month and year of generation. GATS tracks generation attributes and the ownerships of the attributes as they are traded or used to meet renewable portfolio standards ("RPS") and other programs, typically for generators whose energy is settled in the PJM market or whose facility is located in the PJM footprint. M-RETS tracks renewable energy generation and assists in verifying compliance with individual state/provincial RPS requirements or voluntary programs, for generators located in South and North Dakota, Minnesota, Wisconsin, Iowa, Illinois and Ohio. NAR tracks renewable energy generation from facilities typically outside of the M-RETS and PJM footprints.

Each agreement for the acquisition of a REC shall have a specified term. All RECs used by Ameren to comply with the statutory requirements shall be retired in compliance with 1-75 (c) (4).

3.3.3.1 Ameren Illinois Company. The IPA proposes that Ameren shall meet the renewable energy resource portfolio standard for the Plan year through the acquisition of qualifying renewable energy credits ("RECs") as defined in Section 1-10 of the IPA Act. The acquisition of RECs for this period meets the requirements of the IPA Act and is preferable to the direct acquisition of energy from qualifying renewable resources at this time.

Sufficient RECs to comply with the quantities established by 1-75 (c) (1) of the IPA Act shall be acquired on the basis of (1) the requirements established in 1-75 (c) (3) of the IPA Act and (2) price, as determined by comparing qualifying bids meeting approved benchmarks. Such acquisitions of renewable energy credits shall be memorialized with a Master Renewable Energy Certificate Purchase and Sale Agreement.

As noted, the statute establishes a methodology for calculating annual volumetric goals for the portfolio as well as establishing a Renewable Energy Resource Budget ("RRB") that serves as a maximum cost cap for meeting those goals. In the event that the cost cap is met, purchases of renewable energy resources in excess of existing contract amounts would be limited or curtailed, leaving the annual volumetric goal unmet. Table U below presents the Annual Volume Targets resulting from the application of the statute's standards to the Ameren portfolio for planning years 2008-2009, 2009-2010, and 2010-2011. The IPA notes that 600,000 MWh are already purchased under 20 year contracts and therefore the Planning Year RPS Volume Target (MWh) listed in Table Z for 2012-2013 will be reduced by 600,000 MWh and the result will be the quantity of one year RECs solicited in the spring of 2012.

TABLE Z: ANNUAL AMEREN RPS VOLUME TARGETS

Ameren RPS Volume Targets				
Planning Year	Reference Year	Reference Year Delivered Volume (MWh)	Planning Year RPS % Target	Planning Year RPS Volume Target (MWh)
2008-2009	2006-2007	20,719,607	2.00%	414,392
2009-2010	2007-2008	17,984,564	4.00%	719,383
2010-2011	2008-2009	17,217,197	5.00%	860,860
2011-2012	2009-2010	15,869,084	6.00%	952,145
2012-2013	2010-2011	16,048,235	7.00%	1,123,376

Per the statute, the higher of two separate calculations is used to establish each planning year's RBB. Tables AA and BB below presents the Annual Renewable Energy Resource Budgets resulting from the application of the statute's standards to the Ameren portfolio for planning year 2012-2013. The IPA makes note of a change to the procurement plan for this year in that Ameren Illinois began collecting money from customers on its real time pricing tariffs starting June 1, 2010 pursuant to the legislative requirement. Ameren Illinois collected $424,440 from such customers for the period June 1, 2010 through May 31, 2011. The legislation requires the IPA to increase its spending on the purchase of renewable energy resources to be procured by the electric utility for the next plan year by an amount equal to the amounts collected by the utility under the alternative compliance payment rate or rates in the prior year ending May 31. The IPA has therefore added this quantity to its RRB calculations (listed under HSS/RTP Supply Portfolio calculations). Additionally, the "Planning year Projected Total Delivery Volume" in the Tables reflect the aggregate projected portfolio minus losses. Lastly, as noted above, Rate Class DS/BGS-3A was declared competitive on May 1, 2011. In accordance with the statute, volumes representing the rate class have been removed from the following calculation yielding a smaller "Base year volume for eligible retail customers" in Table BB.

The IPA also notes that 600,000 MWh are already purchased under 20 year contracts and therefore the Total IPA RRB Calculations listed in Table W will be reduced by an amount associated with the confidential REC value of such contracts. The result will be the IPA RRB associated with purchases of one year RECs in the spring of 2012.

TABLE AA: ANNUAL AMEREN RRB CALCULATIONS – OPTION A

Option A (Incremental Increase from Prior Year)		
IPA Supply Portfolio Calculations (RRB)		**2012-2013**
(A) Incremental amount per MWh paid in 2011	$	0.0583
(B) Planning Year Projected Total Delivery Volume		13,867,609
(C) Planning Year Option A Cost Cap [A * B]	$	808,482
HSS/RTP Supply Portfolio Calculations (RRB)		
(D) Compliance Year Budget	$	424,440
Total IPA RRB Calculations		
(E) Gross Budget [C + F]	**$**	**1,232,922**

TABLE BB: ANNUAL AMEREN RRB CALCULATIONS – OPTION B

Option B (Percentage Increase on Base year)		
IPA Supply Portfolio Calculations (RRB)		**2012-2013**
(A) Base year volume for eligible retail customers (MWH)		17,658,276
(B) Base year cost for eligible retail customers	$	1,582,184,107
(C) Base year Average Delivered Electricity Unit Cost - [B / A]	$	89.6001
(D) Planning Year Incremental RPS Cost Limit		2.015%
(E) Planning Year Maximum Unit Cost Increase [C * D]	$	1.8054
(F) Planning Year Projected Total Delivery Volume (MWH)		13,897,609
(G) Compliance Year Budget [E * F]	$	25,090,743
HSS/RTP Supply Portfolio Calculations (RRB)		
(H) Compliance Year Budget	$	424,440
Total IPA RRB Calculations		
(I) Gross Budget [G + H]	**$**	**25,515,183**

3.3.3.2 Commonwealth Edison. ComEd shall meet the renewable energy resource portfolio standard for the Plan year through the acquisition of qualifying renewable energy credits ("RECs") as defined in Section 1-10 of the IPA Act. The acquisition of RECs for this period meets the requirements of the IPA Act and is preferable to the direct acquisition of energy from qualifying renewable resources at this time.

Sufficient RECs to comply with the quantities established by 1-75 (c) (1) of the IPA Act shall be acquired on the basis of (1) the requirements established in 1-75 (c) (3) of the IPA Act and (2) price, as determined by comparing qualifying bids meeting approved benchmarks. Such acquisitions of renewable energy credits shall be memorialized with a Master Renewable Energy Certificate Purchase and Sale Agreement.

As note, the statute establishes a methodology for calculating annual volumetric goals for the portfolio as well as establishing a Renewable Energy Resource Budget (RRB) that serves as a maximum cost cap for meeting those goals. In the event that the cost cap is met, purchases of renewable energy resources in excess of existing contract amounts would be limited or curtailed, leaving the annual volumetric goal unmet. Table CC below cites the volume goals.

Table CC below presents the Annual Volume Targets resulting from the application of the statute's standards to the ComEd portfolio for planning year 2012-2013.

TABLE CC: ANNUAL COMED RPS VOLUME TARGETS

ComEd RPS Volume Targets				
Planning Year	Reference Year	Reference Year Delivered Volume (MWh)	Planning Year RPS % Target	Planning Year RPS Volume Target (MWh)
2008-2009	2006-2007	39,802,463	2.00%	796,049
2009-2010	2007-2008	39,109,145	4.00%	1,564,366
2010-2011	2008-2009	37,740,282	5.00%	1,887,014
2011-2012	2009-2010	35,284,241	6.00%	2,117,054
2012-2013	2010-2011	37,105,691	7.00%	2,597,398

Per the statute, the higher of two separate calculations is used to establish each planning year's RBB. Tables DD and EE below presents the Annual Renewable Energy Resource Budgets resulting from the application of the statute's standards to the ComEd portfolio for planning year 2012-2013. Additionally, the "Planning year Projected Total Delivery Volume" in the Tables reflect the aggregate projected portfolio minus losses.

TABLE DD: ANNUAL COMED RRB CALCULATIONS – OPTION A

Option A (Incremental Increase from Prior Year)	
IPA Supply Portfolio Calculations (RRB)	**2012-2013**
(A) Incremental amount per MWh paid in 2011	$0.0570
(B) Planning Year Projected Total Delivery Volume	24,037,807
(C) Planning Year Option A Cost Cap [A * B]	$1,370,155
HEP Supply Portfolio Calculations (RRB)	
(D) Compliance Year Budget	$1,499,113
Total IPA RRB Calculations	
(E) Gross Budget [C + D]	**$2,869,268**

TABLE EE: ANNUAL COMED RRB CALCULATIONS – OPTION B

Option B (Percentage Increase on Base year)	
IPA Supply Portfolio Calculations (RRB)	**2012-2013**
(A) Base year volume for eligible retail customers (MWH)	39,802,463
(B) Base year cost for eligible retail customers	$3,736,750,000
(C) Base year Average Delivered Electricity Unit Cost - [B / A]	$93.8824
(D) Planning Year Incremental RPS Cost Limit	2.015%
(E) Planning Year Maximum Unit Cost Increase [C * D]	$1.8917
(F) Planning Year Projected Total Delivery Volume (MWH)	24,037,807
(G) Compliance Year Budget [E * F]	$45,472,319
HEP Supply Portfolio Calculations (RRB)	
(H) Compliance Year Budget	$1,499,113
Total IPA RRB Calculations	
(I) Gross Budget [G + H]	**$46,971,432**

The Procurement Administrator shall seek to acquire the Target amount of RECs, but no more without exceeding the RRB.

3.3.3.3 Material Instances of Supplier Default on Renewable Energy Contracts. The IPA proposes the following in the event that a Utility's counterparty to a contract defaults and the default results in a reduction in the number of renewable energy credits ("RECs") retired on the utility's behalf for any given plan year (ending May 31):

If the contract volume effected by the default represents less than 5% of the annual RPS obligation.. The Utility will request price proposals from the other vendors supplying RECs in that compliance year for replacement RECs of the same vintage and specifications of those the defaulting vendor has failed to deliver. Terms in RECs contracts will allow for contract amendment to facilitate additional REC volume delivery under default circumstances. To accommodate replacement REC purchases, the IPA proposes to extend the allowable vintage ranges for complying RECs within the terms of the supply contracts negotiated in the 2012 procurement cycle. In the event that replacement RECs are purchased by the Utility due to a default, the Utility will first use the collateral on hand from the defaulting supplier to satisfy costs associated with securing replacement RECs.

If the contract volume effected by the default represents greater than 5% of the annual RPS obligation. The IPA will solicit bids from all firms deemed qualified as REC suppliers in the most recent REC solicitation. The solicitation will seek replacement RECs of the same vintage and specifications as those the defaulting vendor has failed to deliver. To accommodate replacement REC purchases, the IPA proposes to extend the allowable vintage ranges for complying RECs within the terms of the supply contracts negotiated in the 2012 procurement cycle. The Utility will first use the collateral on hand from the defaulting supplier to satisfy costs associated with securing replacement RECs.

The IPA does not interpret the statute as allowing the transfer of Renewable Resources Budget funds between compliance years.

With respect to any contract entered into by Ameren and ComEd as a result of an IPA procurement process, if Ameren's and ComEd's counterparty to the contract defaults, and such default results in a reduction in the number of renewable energy credits ("RECs") retired on the utility's behalf for any given plan year (ending May 31), the IPA shall add the shortfall of RECs to the quantity of RECs to purchase through RFPs issued for subsequent plan years. Any dollar amounts that were not spent due to the default, plus any additional collateral retained by Ameren and ComEd due to the default, shall be added to the REC budgets for those subsequent plan years. If possible, the purchase of the replacement RECs shall be reflected in the subsequent procurement plan(s). However, even if not explicitly reflected in a procurement plan, the IPA may include in an RFP the purchase of replacement RECs associated with recent defaults, if such inclusion is deemed acceptable, unanimously by the procurement administrator, the procurement monitor, and Ameren and ComEd.

The IPA recognizes that, except in the case of defaults on long-term contracts, it may not be feasible to replace RECs with those of identical vintage. For example, if sometime late in the Plan year, it becomes clear that a supplier will fail to supply all of the June 2012-May 2013 vintage RECs that the latter agreed to supply, the IPA may be hard pressed to hold a special RFP before the end of the vintage year. Furthermore, even when possible, the expense of holding a special RFP for what might be a small quantity of replacement RECs would be high. If the Commission concludes that separate procurements for replacement RECs are necessary, the IPA will comply.

3.4 Transmission Resources.

3.4.1 Background. Ameren and ComEd acquire certain transmission-related products and services to effectuate delivery of power and energy to the applicable loads. These services may include Network Transmission Service and Ancillary Services. Further, Ameren may be allocated certain Financial Transmission/Auction Revenue Rights.

3.4.2 Evaluation. Ameren and ComEd are obligated by the MISO and PJM Tariffs to secure specific certain transmission service related products. As these are tariff mandated and governed transactions, the IPA procurement plan validates those obligations.

3.4.3 Recommendations. The IPA recommends the following measures with regard to Ameren and ComEd transmission arrangements:

3.4.3.1 Ameren Illinois Company. Network Transmission Service, and Ancillary Services as well as Financial Transmission/Auction Revenue Rights for Ameren should be managed as follows:

Network Integrated Transmission Service. Network Integrated Transmission Service ("NITS") is described in Section III of Module B to the MISO Tariff. Ameren utilizes such NITS to reliably deliver capacity and energy from their Network Resources to their Network Loads – namely their Native Load obligations.

The MISO tariff requires each NITS customer to complete an application for service, complete any applicable technical arrangements in conjunction with the Transmission Provider and Transmission Owner and execute both a Service Agreement and a Network Operating Agreement.

Ameren has acquired the necessary NITS in accordance with the tariff. The cost for this service shall be established in the applicable MISO tariff schedules.

Ancillary Services. Ancillary Services are services that are necessary to support capacity and the transmission of energy from resources to loads while maintaining reliable operation of the transmission system. Effective January 2009, the Midwest ISO implemented an Ancillary Services market to provide regulation service and operating reserve service (both spinning and supplemental) reserves. The Ameren Illinois Company procures these required services through the MISO Ancillary Services market.

Auction Revenue Rights. Auction Revenue Rights ("ARRs") are not a power and energy resource. However, the nomination and subsequent allocation of such rights to Ameren generally serves to reduce the cost of congestion borne by Ameren (and, thus, ultimately by their customers).

As part of the 2011 ARR allocation process at MISO, Ameren received a set of ARR entitlements and were awarded ARRs for the 2011 planning year.

For future planning years, Ameren shall continue to actively participate in the MISO ARR nomination and allocation process and shall seek to nominate those ARRs with an expected positive value. Ameren recognizes they may not be allocated all of the ARRs requested and they may be required by the MISO to accept certain ARRs which do not have an expected positive value.

Ameren shall retain the allocated ARRs and receive associated credits for its customers. Ameren should make no further changes except to the extent that should the delivery point for one or more of the energy resources be other than within the AMIL balancing authority, Ameren may attempt to reallocate the applicable ARRs from their historical resource points to those which align more closely with the designated energy resource delivery point.

3.4.3.2 ComEd Transmission Resources. In addition to the acquisition of power and energy related products as detailed above, ComEd is obligated by the PJM Tariff to acquire certain transmission service related products and services to effectuate delivery of power and energy to the applicable loads including Ancillary Services. Further, ComEd may be allocated certain Financial Transmission/Auction Revenue Rights

Ancillary Services. Ancillary Services are services that are necessary to support capacity and the transmission of energy from resources to loads while maintaining reliable operation of the transmission system. PJM operates an Ancillary Services market to provide regulation service and operating reserve service (both spinning and supplemental) reserves. ComEd will secure these required services through the PJM Ancillary Services market.

Auction Revenue Rights. Auction Revenue Rights ("ARRs") are not a power and energy resource. However, the nomination and subsequent allocation of such rights to ComEd generally serves to reduce the cost of congestion borne by ComEd (and, thus, ultimately by their customers). As part of the 2010-11 ARR allocation process at PJM, ComEd received a set of ARR entitlements and was awarded ARRs for that planning year.

For future planning years, ComEd shall continue to actively participate in the PJM ARR nomination and allocation process and shall seek to nominate those ARRs with an expected positive value. ComEd recognizes they may not be allocated all of the ARRs requested and they may elect certain ARRs which ultimately do not have a positive value. ComEd shall retain the allocated ARRs and receive associated credits for its customers. All proceeds and costs of such sales, including costs incurred to evaluate and execute such a strategy, will be passed to customers through Rider PE.

4 Additional Issues

4.1 Clean Coal. Section 75 of the IPA Act includes a requirement that annual procurement plans include electricity generated by the initial clean coal facilities. Moreover, it is the goal of the State that by January 1, 2025, 25% of the electricity used in the State shall be generated by cost-effective clean coal facilities. Thus, the IPA may also propose in a procurement plan the procurement of electricity generated by a clean coal facility that does not qualify as the initial clean coal facility. Such a proposal is, however, subject to the approval of the Illinois Commerce Commission under the standards set forth in section 16-111.5(d)(4) of the PUA. That standard requires a demonstration that the proposed procurement will result in electric service that is the lowest total cost over time. The record is insufficient at this time to conclude that conducting a procurement event for a clean coal sourcing agreement would result in the lowest total cost over time. Therefore, the IPA is not proposing the procurement of electricity generated from clean coal facilities at this time.

4.2 Senate Bill 1652. The Illinois General Assembly passed SB1652 on August 26, 2011 and sent it to the Governor on August 29, 2011. Although the Governor vetoed that Bill on September 12, legislative efforts to override were successful with the bill becoming law as Public Act 97-0616 on October 31, 2011. With the passage of the bill, it impacts the amount of energy and RECs that are proposed to be procured in the Plan. P.A. 97-0616 amends the PUA by adding subsection k-5 to section 16-111.5. That subsection requires the IPA to conduct a separate procurement event within 120 days of the effective date of the new law to procure both energy and RECs for the period June 1, 2013 through December 31, 2017.

The amount of energy that is to be procured is to be based upon an updated forecast of the minimum monthly load requirements shown in the forecasts. The amount of RECs that is to be procured is to be based on the amount of RECs that would satisfy the requirements set out in section 1-75(c) of the IPA Act. The procurement event under P.A. 97-0616 will occur in February 2012. The volumes of energy and RECs to be procured pursuant to the Plan will be revised downward in proportion to the amount of energy and RECs procured in the new procurement event. The IPA will work with Staff, the Procurement Administrator, the Procurement Monitor, and the Utilities to revise the portfolio volumes.

Ameren Illinois Company
Load Forecast for the period June 1, 2012 – May 31, 2017

Purpose and Summary

The development of the load forecast is an essential step in the development of the Ameren Illinois procurement plan. The load forecast provides the basis for subsequent analysis resulting in a projected system supply requirement. The load forecast process includes a multi-year historical analysis of loads, analysis of switching trends, and competitive retail markets by customer class, known and projected changes affecting load, customer class specific growth forecasts and an impact analysis of statutory programs related to demand response, energy efficiency and renewable energy. The results of this analysis and modeling include a 5 year summary analysis of the projected system supply requirements.

Load Forecast Methodology

Energy Forecast

The models developed for the June 1, 2012 – May 31, 2017 load forecast use both econometric and the statistically adjusted end use (SAE) approaches. The traditional approach to forecasting monthly sales is to develop an econometric model that relates monthly sales to weather, seasonal variables, and economic conditions. The strength of econometric models is that they are well suited to identify historical trends and to project these trends into the future. In contrast, the strength of the end-use modeling approach is the ability to identify the end use factors that are driving energy use. By incorporating an end-use structure into an econometric model, the statistically adjusted end-use modeling framework exploits the strengths of both approaches. This SAE approach was used for all residential classes, while traditional econometric models were developed for the remaining commercial, industrial and public authority classes. Lighting sales were forecasted by either exponential smoothing models or econometric models. Models were developed using revenue month sales data spanning from January 1995 (data for some models start later than 1995) to March 2011. Economic variables were obtained from Moody's Economy.com. Saturation and efficiency data were obtained from EIA. Revenue month weather data was created using billing cycles and weighting daily average temperatures according to the billing cycles. After revenue month sales models were created, the models were simulated with calendar month weather (and calendar month days where applicable) to obtain the calendar month sales forecast.

Since the rate structure changed in 2007 and it was not possible to reclassify the historical data according to the new rates; therefore, modeling was done on each revenue class, i.e., residential, commercial, industrial, public authority and lighting. Next step in the energy forecast was to allocate the sales forecast into the new delivery service rates. DS1 class is equivalent to residential class, and lighting sales are equivalent to DS5. Commercial, industrial and public authority sales were separated into the DS2, DS3A, DS3B and DS4 classes after calculating the shares of each delivery service class within a revenue class.

Residential SAE Model

The SAE modeling framework defines energy use in residential sector (USEy,m) in year (y) and month (m) as the sum of energy used by heating equipment ($Heat_{y,m}$), cooling equipment ($Cool_{y,m}$) and other equipment ($Other_{y,m}$). The equation for this is as follows:

$$\mathrm{Use}_{y,m} = \mathrm{Heat}_{y,m} + \mathrm{Cool}_{y,m} + \mathrm{Other}_{y,m} \qquad (1)$$

Although monthly sales are measured for individual customers, the end-use components are not. Substituting estimates for the end-use elements gives Equation 2,

$$\mathrm{Use}_{y,m} = a + b_1 \times \mathrm{XHeat}_{y,m} + b_2 \times \mathrm{XCool}_{y,m} + b_3 \times \mathrm{XOther}_{y,m} + \varepsilon_{y,m} \qquad (2)$$

where $XHeat_{y,m}$, $XCool_{y,m}$, and $XOther_{y,m}$ are explanatory variables constructed from end-use information, weather data, and market data. As shown below, the equations used to construct these X variables are simplified end-use models, and the X variables are the estimated usage levels for each of the major end use based on these models. The estimated model can then be thought of as a statistically adjusted end-use model, where the estimated slopes are the adjustment factors.

Constructing XHeat- Electric

Energy use by space heating systems depends on heating degree days, heating equipment share levels, heating equipment operating efficiencies, billing days, average household size, household income, and energy price. The heating variable is represented as the product of an annual equipment index and a monthly usage multiplier. That is,

$$\mathrm{XHeat}_{y,m} = \mathrm{HeatIndex}_{y} \times \mathrm{HeatUse}_{y,m} \qquad (3)$$

where $XHeat_{y,m}$ is estimated heating energy use in year (y) and month (m), $HeatIndex_y$ is the annual index of heating equipment, and $HeatUse_{y,m}$ is the monthly usage multiplier.

The HeatIndex is defined as a weighted average across equipment saturation levels normalized by operating efficiency levels. Given a set of fixed weights, the index will change over time with changes in equipment saturations (Sat) and operating efficiencies (Eff). Formally, the equipment index is defined as:

$$HeatIndex_y = StructuralIndex_y \, x \sum_{Type} Weight^{Type} \, x \frac{\left(Sat_y^{Type} \big/ Efficiency_y^{Type} \right)}{\left(Sat_{05}^{Type} \big/ Efficiency_{05}^{Type} \right)} \qquad (4)$$

In the above expression, 2005 is used as a base year for normalizing the index. The ratio is equal to 1 in 2005. In other years, it will be greater than 1 if equipment saturation levels are above their 2005 level. This will be counteracted by higher efficiency levels, which will drive the index downward. The weights are defined as follows.

$$\mathrm{Weight}^{Type} = (\mathrm{Energy}_{05}^{Type} / \mathrm{HH}_{05}) \times \mathrm{HeatShare}_{05}^{Type} \qquad (5)$$

($Energy_{05}^{Type}/HH_{05}$) is the unit energy consumption of each end-use in 2005 according to EIA data adjusted for each service territory. $HeatShare_{05}^{Type}$ is the saturation levels for each heating end-use in 2005 multiplied by a structural index with base year 2005, which is a function of surface area and building shell efficiency.

$$HeatShare_{05}^{Type} = Saturation_{05}^{Type} \text{ x Structural } Index_{05} \qquad (6)$$

where

Structural $Index_y$ = (Building Shell $Efficiency_y$ x Surface $Area_y$) / (Building Shell $Efficiency_{05}$ x Surface $Area_{05}$) (7)

where

Surface Area = 892 + 1.44 x House Size (8)

The end-use saturation and efficiency trends are developed from Energy Information Administration (EIA)'s regional projections.

Heating system usage levels are impacted on a monthly basis by several factors, including weather, household size, income levels, prices and billing days. Since the revenue month heating degree days are used in the SAE index, HDD is not used as a separate variable in the model. The estimates for space heating equipment usage levels are computed as follows:

$$HeatUse_{y,m} = \left(\frac{BDays_{y,m}}{AvgBDays}\right) x \left(\frac{WgtHDD_{y,m}}{HDD_{05}}\right) x \left(\frac{Income_{y,m}}{Income_{05}}\right)^{0.20} x \left(\frac{HHSize_{y,m}}{HHSize_{05}}\right)^{0.25} x \left(\frac{ElecPrice_{y,m}}{ElecPrice_{05,7}}\right) x \left(\frac{GasPrice_{y,m}}{GasPrice_{05,7}}\right) \quad (9)$$

where $Price_{y,m}$ is the average residential real price of electricity in year (y) and month (m), $Price_{05}$ is the average residential real price of electricity in 2005, $HHIncome_{y,m}$ is the average real income per household in a year (y) and month (m), $HHIncome_{05}$ is the average real income per household in 2005, $HHSize_{y,m}$ is the average household size in a year (y) and month (m), $HHSize_{05}$ is the average household size in 2005, $HDD_{y,m}$ is the revenue month heating degree days in year (y) and month (m), and HDD_{05} is the annual heating degree days for 2005.

Constructing XCool- Electric

To construct XCool index, the same procedures as in XHeat index are followed; the only difference is that cooling degree days are used instead of heating degree days.

Constructing XOther- Electric

Monthly estimates of non-weather sensitive sales can be derived in a similar fashion to space heating and cooling. Based on end-use concepts, other sales are driven by appliance and equipment saturation levels, appliance efficiency levels, average household size, real income, real prices, and billing days. The explanatory variable for other uses is defined as follows:

$$XOther_{y,m} = OtherIndex_y \times OtherUse_{y,m} \qquad (10)$$

The methodology for constructing OtherIndex is the same as heating and cooling indices except for the fact that there is no weather variable used in this index.

Peak Forecast

The monthly peak forecast for Ameren Illinois' eligible customer retail load was performed at the legacy operating company level. For each rate zone (Rate Zone I- Former AmerenCIPS and Former AmerenCIPSME, Rate Zone II- Former AmerenCILCO, and Rate Zone III- Former AmerenIP), historical hourly data was collected. The hourly data used for each rate zone was from 2007 to 2009. For each rate zone, the corresponding daily temperatures were used for building the regression models. The daily temperatures are calculated by averaging the daily high and low values. . The loads were at transmission level and excluded wholesale load.

Methodology:
Using the hourly input data from 2007 to 2009, a daily peak regression model and a daily energy regression model were constructed. A peak and energy model for every DS class (namely DS1, DS2, DS3A, DS3B, DS4 and DS5) was built. This is because each of these DS classes has a different weather response function. For example, DS1 is the most weather-sensitive class.
Year 2008 was taken as a reference calendar year. The actual load for 2008 was weather normalized using the daily peak and energy models, by adopting the Unitized Load Calculation approach. This approach is briefly discussed below.

Unitized Load Calculation:

Using the actual hourly load data estimate the daily peak and daily average load.
Calculate the Unitized Hourly Load using the equation shown below:

Daily peak designated as: $PK_t(0)$

Daily energy designated as: $AVG_t(0)$

Unitized Hourly Load:

$$D_{ht}(0) = \frac{MW_{ht}(0) - AVG_t(0)}{PK_t(0) - AVG_t(0)}$$

The same regression coefficients are used to run-through the normal weather for daily peak and energy.

Weather normalized daily peak designated as: $PK_t(0)'$

Weather normalized daily energy designated as: $AVG_t(0)'$

Normalized hourly load:

$$MW_{ht}(0)' = AVG_t(0)' + D_{ht}(0).(PK_t(0)' - AVG_t(0)')$$

Daily Peak Model

Daily peak loads were modeled using regression within the MetrixND software package. Daily peak load was the dependent variable, and the independent variables included temperature based variables, seasonal variables, day-type variables, calendar variables, and energy growth trend variable. Average daily temperature, defined as the arithmetic mean of the day's high and low temperatures, is the basis for all of the weather variable constructions. Temperature splines are then created from the average daily temperature variable to allow load to respond to temperature in a non-linear fashion. These temperature splines are also interacted with seasonal and weekend variables to allow the temperature response of load to change with respect to these variables (i.e. Load will respond more to an 80 degree day in July than in October, and more on a weekday than a weekend).
..
The daily peak model also includes independent binary variables representing each day of the week, each month of the year, and major holidays. This captures the change in load that is not due to weather variation, such as load reductions due to industrial customers and businesses that may not operate on weekends.

Statistical tests verify that the models fit the data quite well. The R-Squared statistic, which indicates the amount of variation in the dependent variable (load) that is explained by the model, is around 88% on an average. The Mean Absolute Percent Error (MAPE) of the models is around 4.5% on an average, indicating that over all of the years of the analysis, the average day has a small absolute error.

Daily Energy Model

The concept for building the daily energy models is the same as that of daily peak, except that the dependent y-variable is the sum of hourly loads. The R-squared statistic is around 90% on an average for the daily energy models. The MAPE is around 4%.

Forecasting Normal Weather Conditions for the Daily Peak Model

Ameren Illinois defines normal for a weather element as the arithmetic mean of that weather element computed over the 10 year period from 2001-2010. Because daily average temperature is the weather variable of interest for the peak forecast, the daily average temperature for each date must be averaged over the 10 year period. Unfortunately, averaging temperatures by date (i.e. all January 1st values averaged, then all January 2nd values and so on) creates a series of normal temperatures that is relatively smooth (i.e. no extreme values) and therefore devoid of peak load making weather conditions. To ameliorate this situation, a routine known as the "rank and average" method is used. In this method, all 10 years of historical weather data are collected. For each summer and non-summer of each year, the respective degree day data is sorted from the highest value to the lowest. Then the sorted data is averaged across the 10 years, with all of the hottest days in each summer averaged with each other. Likewise, all of the coldest days in each non-summer season are averaged, while the mild days are averaged together.

After the weather has been averaged by the degree day rank, the days are “mapped” back to the actual weather of the reference calendar year, from each year for the historical period. For the forecast period, an average weather shape is used to map the degree days. This way, the “normal” degree days follow a realistic contour. The normal temperature series is run through the daily peak and daily energy forecast models to produce a normal peak load and a normal energy load forecast.

The year 2008 is used as the reference year. We call it the ‘Planning Calendar’. Once we have the normal peak and energy load forecast for 2008, using the unitized load approach discussed above, the normal hourly loads are constructed. This profile shape is extended to the future time periods (2011 to 2018 also called the ‘Actual Calendar’) after applying suitable calendar adjustments. In order to do this, the first step was to simulate the normal weather (from rank and average technique discussed above) from 2011 to 2018. The next step is to replicate the 24-hour profile shape (considered separately for each month) for each day into the forecast period, by considering the peak producing temperature, second peak producing temperature, and so on. Thus we have a profile shape for each day from 2011 to 2018.

Using the peak and energy models, we forecast the normal daily peak and energy loads for the same actual calendar time period. The unitized load formula is then applied to the forecasted values to come up with normal hourly loads for all the years from 2011 to 2018.

Final Forecast Steps

The MetrixLT software is used to apply the hourly shapes developed above under the monthly energy sales forecast. For example, for the month of January-2012 there are 744 hourly values and one energy forecast value. The 744 hourly values are shaped according to the energy value. Suitable loss factors are applied to the shaped values to arrive at final hourly forecast. This is done for each rate-zone and each DS class separately. The final hourly system values (and hence the monthly peaks) are obtained by aggregating the values from each DS class.

Switching Trends and Competitive Retail Market Analysis

It is important to note in any discussion of retail switching the inherent difficulty in projecting future activity. Ameren Illinois necessarily must make some assumption of such future switching levels given that 16-111.5(b) of the PUA requires a five year analysis of the projected balance of supply and demand. In making these assumptions, Ameren Illinois has utilized an extension of existing trends and their best judgment to arrive at the expected values. This was accomplished by first establishing the current trend line utilizing actual switching data by customer class for the post rate freeze period (January 2007 through June 2011). Ameren Illinois then reviewed these trends and using their qualitative judgment made adjustments such that the end result is a forecast generally characterized by increasing switching. Given the difficulties inherent with projecting switching, it is expected that subsequent switching projections for future planning periods will likely differ substantially, and thus will have a like effect upon the projection of Ameren Illinois' power supply requirements for eligible retail customers.

Residential

As of May 1, 2011, there were eight Alternative Retail Electric Suppliers (ARES) registered with both the ICC and Ameren Illinois to serve residential customers in Ameren Illinois territories, as compared to sixteen so registered to serve non-residential customers in Ameren Illinois territories. However, as of the date this plan was prepared, less than 0.1% of residential usage of Ameren Illinois was supplied by ARES (switching is approximately 1.4% when RTP is considered). However, Ameren Illinois expects the amount of load served by ARES could increase over time since several ARES have expressed a desire to supply more residential load within Ameren Illinois.

Residential switching could be positively influenced by an increase in the number of ARES willing to serve residential customers, aggressive marketing campaigns or the development of value added products and services. It is worth noting that the amount of ARES approved to serve residential customers has increased from five to eight in the last twelve months. More so, significant reductions in market prices or an increase in aggregation of residential customers would reasonably be expected to have an impact upon residential switching rates.

In addition to the ARES options, residential customers may opt for real time pricing through a program administered for the Ameren Illinois by CNT Energy. Since program inception in 2007, participation in the program has been steadily increasing and now exceeds 1.0% of available load.

Ameren Illinois estimates that the combination of residential switching to ARES and real time pricing will be greater than 10% of energy by the end of the five year planning period. But it should be noted that the variability in this forecast could be considerable and such variability could be driven by the aggressiveness of ARES marketing campaigns (which as of this writing are commencing), customer acceptance and the headroom between ARES contracts and Ameren Illinois fixed price tariffs. Ameren Illinois proposes that it monitor switching, especially in the residential class, and provide an updated five-year forecast to the IPA and the Commission in early November 2011. During the active delivery year of 2012 and in the event that Ameren Illinois' energy forecast increases above the High Forecast or decreases below the Low Forecast, Ameren Illinois shall promptly notify the IPA. The IPA will subsequently convene a meeting with Ameren Illinois, Commission staff, and the procurement administrator to determine whether it is appropriate to rebalance the portfolio, and if so, to what extent and how such a rebalancing can be achieved.

0-149 kW Non-Residential

This customer class has seen approximately 45% load switching since January 1, 2007 which represents about a 7% increase over the prior year. Future switching patterns are difficult to predict due to uncertain market conditions. However, as long as market prices stay below the Ameren Illinois, one could reasonably expect switching to continue its upward trend.

In addition, now that ARES have been successful in gaining significant switching among the larger industrial and commercial customer classes, it is reasonable to assume ARES will focus efforts on the smaller customer classes. Finally, customers in this class also have an option for real time pricing, giving them other alternatives to switch away from tariff.

Ameren Illinois estimates that switching in this class will be approximately 59% of load by the end of the five year planning period.

150-399 kW Non-Residential

This customer class has seen approximately 75% load switching since January 1, 2007 which represents about a 7% increase over the prior year. Future switching patterns are difficult to predict due to uncertain market conditions. However, as long as market prices stay below the Ameren Illinois tariff, one could reasonably expect switching to continue its upward trend.

In addition, a key development is the ICC declaration that this class of customers is competitive with a transition period effective May 1, 2011. This means that customers currently taking fixed price supply from Ameren Illinois will be allowed to continue until May 1, 2014, unless such customers switch to ARES or real time pricing before then, at which point such customers cannot return to Ameren Illinois fixed price supply. Any customer that currently takes supply from ARES or from Ameren Illinois real time pricing will not be able to return to Ameren Illinois fixed price supply. Effective May 1, 2014, all customers must receive supply from either ARES or Ameren Illinois real time pricing.

Given this development, Ameren Illinois estimates that load switching in this class will be 100% by the end of the five year planning period.

400-999 kW Non-Residential

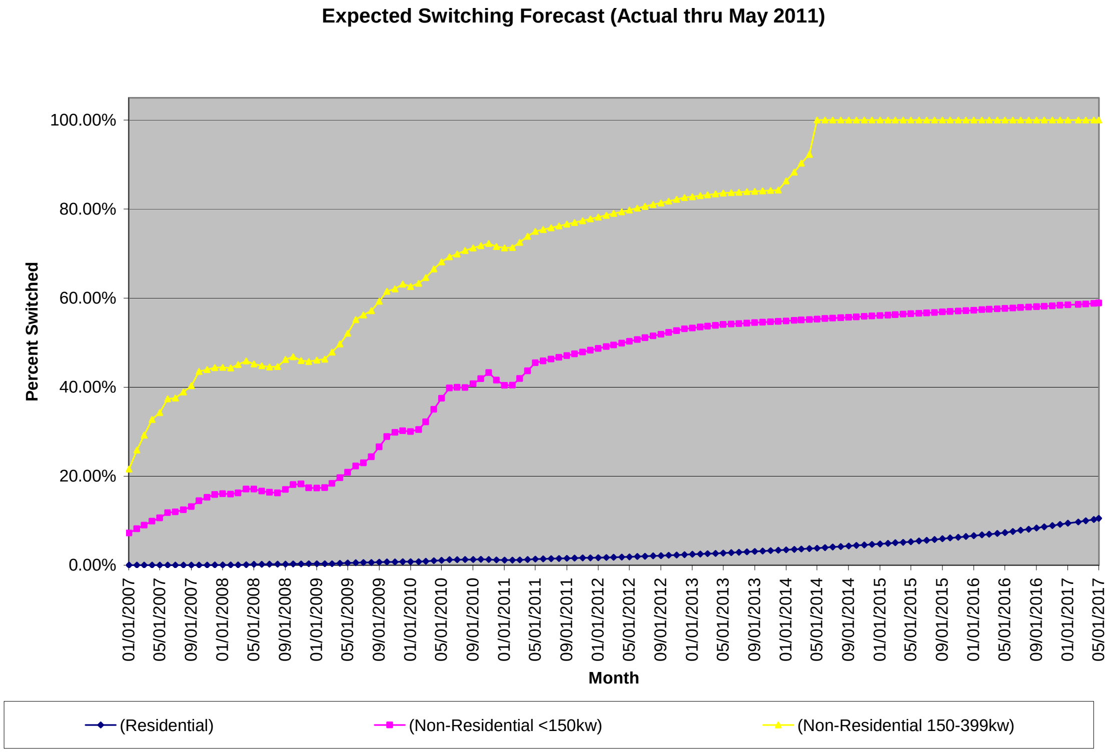
Section 16-113 (f) of the PUA declared this class to be competitive on June 1, 2010. As such, all customers are required to take supply under an ARES or the Ameren Illinois real time pricing tariff. Therefore, this customer class assumes 100% switching and is therefore no longer considered part of the Ameren Illinois fixed price load.

1,000 kW and Greater Non-Residential

This customer class is declared competitive and therefore these customers can no longer take the fixed price supply after May 31, 2008 and is therefore not included in the fixed price load.

Switching Patterns

As noted previously, it is reasonable to expect further switching among residential and small commercial customer classes to either real time pricing or ARES as such suppliers increase focus on smaller customer classes and current market prices stay below those in the Ameren Illinois tariff. Expected values through May 31, 2017 are included in the graph below:



Known or Projected Changes to Future Loads

Known or projected changes to future loads include:

1) Customer Switching behavior, as discussed in Section II.B.(2).
2) Demand Response Program Initiatives, as discussed in Section II.c.(1)
3) Energy Efficiency Initiatives, as discussed in Section II.c.(3)

Growth Forecasts by Customer Class

For the residential electric customer class, Ameren Illinois currently projects a 5-year Compound Annual Growth rate of 0.27%. Commercial growth rates for Ameren Illinois are projected to be 0.22%.

Analysis of the Impact of Any Demand Side Initiatives

Demand Response Programs

Section 12-103 of Public Act 095-0481 establishes specific requirements for Demand Response Programs to reduce peak demand of eligible retail customers.
Ameren Illinois previously had an air conditioner demand response pilot program which has been discontinued. The ICC order in the most recent Ameren Illinois energy efficiency plan (Docket 10-0568) recommended that Ameren Illinois institute a pilot of the Voltage

Optimization Program and explore other measures to meet the demand response requirement. Until such time as this is complete, the demand response impact relative to Ameren Illinois' system load requirements will be negligible and therefore will have no impact on Capacity requirements. Ameren Illinois will update the forecast of demand response programs and impact in future procurement plans.

Energy Efficiency Programs

Section 12-103 (b) of Public Act 095-0481 and the ICC Order pursuant to the Ameren Illinois three year energy efficiency plan establish specific requirements for Energy Efficiency Programs that reduce energy consumption of delivery services customers. The effective reduction in Ameren Illinois supply requirements to be acquired through the RFP process (net of customer switching) is projected to be between June 1, 2012 and May 31,2017:

2012	159,162 MWh
2013	134,341 MWh
2014	130,399 MWh
2015	127,850 MWh
2016	124,204 MWh

(Please note that the above values only reflect the impact upon the amount of energy that Ameren Illinois has to acquire to serve the eligible retail customer loads, after consideration of switching).

Updated Attachment C: Ameren Rate Class Volume Projections

	Projected Monthly Volume Requirements						
Contract Month	DS1 MWH	DS2 MWH	DS3a MWH	DS5 MWH	QF MWH	Total Load MWH	Net Load MWh
June-12	981,549	258,988	41,418	25,401	(41,040)	1,307,356	1,266,316
July-12	1,294,257	285,908	44,630	24,942	(42,408)	1,649,736	1,607,328
August-12	1,282,950	282,318	42,873	26,165	(42,408)	1,634,306	1,591,898
September-12	901,988	243,839	39,011	29,237	(41,040)	1,214,075	1,173,035
October-12	746,174	226,188	38,633	31,413	(42,408)	1,042,407	999,999
November-12	811,999	215,111	35,950	35,090	(41,040)	1,098,151	1,057,111
December-12	1,107,911	244,305	37,374	38,497	(42,408)	1,428,087	1,385,679
January-13	1,189,471	250,357	36,509	41,282	(42,408)	1,517,619	1,475,211
February-13	967,002	232,969	33,303	36,275	(38,304)	1,269,549	1,231,245
March-13	887,978	230,974	33,967	32,566	(42,408)	1,185,486	1,143,078
April-13	681,257	205,299	30,635	30,265	(41,040)	947,455	906,415
May-13	710,264	214,622	32,585	27,218	(42,408)	984,690	942,282
June-13	961,907	244,716	34,592	25,265	0	1,266,481	1,266,481
July-13	1,268,660	271,253	37,745	24,625	0	1,602,282	1,602,282
August-13	1,258,286	269,331	36,787	26,008	0	1,590,412	1,590,412
September-13	883,717	234,121	33,995	28,742	0	1,180,576	1,180,576
October-13	728,503	218,391	34,175	31,249	0	1,012,319	1,012,319
November-13	793,756	209,133	32,318	34,847	0	1,070,054	1,070,054
December-13	1,086,578	238,122	34,030	38,396	0	1,397,126	1,397,126
January-14	1,164,323	244,130	29,314	41,178	0	1,478,945	1,478,945
February-14	946,928	228,568	23,162	36,164	0	1,234,823	1,234,823
March-14	869,464	226,315	19,690	32,372	0	1,147,842	1,147,842
April-14	667,017	201,395	14,228	30,137	0	912,776	912,776
May-14	696,177	210,773	0	27,132	0	934,082	934,082
June-14	944,115	240,008	0	25,174	0	1,209,297	1,209,297
July-14	1,248,093	265,747	0	24,542	0	1,538,382	1,538,382
August-14	1,239,410	263,786	0	25,890	0	1,529,086	1,529,086
September-14	870,532	229,355	0	28,640	0	1,128,527	1,128,527
October-14	717,092	213,944	0	31,186	0	962,222	962,222
November-14	782,094	204,546	0	34,777	0	1,021,417	1,021,417
December-14	1,073,037	233,009	0	38,315	0	1,344,361	1,344,361
January-15	1,129,126	239,671	0	41,097	0	1,409,895	1,409,895
February-15	918,465	223,837	0	36,069	0	1,178,371	1,178,371
March-15	844,324	221,570	0	32,295	0	1,098,188	1,098,188
April-15	650,081	197,153	0	30,094	0	877,328	877,328
May-15	682,348	206,207	0	27,053	0	915,608	915,608

Contract Month	DS1 MWH	DS2 MWH	DS3a MWH	DS5 MWH	QF MWH	Total Load MWH	Net Load MWh
Projected Monthly Volume Requirements							
June-15	927,443	234,669	0	25,099	0	1,187,211	1,187,211
July-15	1,227,843	259,678	0	24,477	0	1,511,997	1,511,997
August-15	1,217,004	257,719	0	25,829	0	1,500,551	1,500,551
September-15	855,097	224,101	0	28,588	0	1,107,787	1,107,787
October-15	701,816	209,008	0	31,134	0	941,958	941,958
November-15	762,249	199,849	0	34,731	0	996,829	996,829
December-15	1,044,199	227,743	0	38,246	0	1,310,188	1,310,188
January-16	1,121,402	234,356	0	41,019	0	1,396,777	1,396,777
February-16	948,877	221,959	0	35,772	0	1,206,609	1,206,609
March-16	841,201	215,814	0	32,397	0	1,089,412	1,089,412
April-16	645,896	192,572	0	30,297	0	868,765	868,765
May-16	678,850	201,133	0	27,078	0	907,061	907,061
June-16	923,930	228,816	0	25,062	0	1,177,808	1,177,808
July-16	1,223,691	253,109	0	24,624	0	1,501,424	1,501,424
August-16	1,212,623	251,198	0	25,833	0	1,489,654	1,489,654
September-16	851,541	218,470	0	28,837	0	1,098,848	1,098,848
October-16	697,723	203,754	0	31,087	0	932,564	932,564
November-16	757,027	194,855	0	34,773	0	986,655	986,655
December-16	1,036,745	222,286	0	38,187	0	1,297,218	1,297,218
January-17	1,111,446	228,149	0	40,978	0	1,380,573	1,380,573
February-17	904,254	212,828	0	36,001	0	1,153,083	1,153,083
March-17	831,871	211,046	0	32,171	0	1,075,088	1,075,088
April-17	641,854	187,702	0	29,973	0	859,529	859,529
May-17	676,187	196,114	0	26,927	0	899,227	899,227

Updated Attachment D: Ameren Total and Average Monthly Loads

Contract Month	Total Load (MWh)		Average Load	
	On Peak	Off Peak	On Peak	Off Peak
Jun-12	686,633	579,683	2,044	1,510
Jul-12	820,066	787,262	2,441	1,930
Aug-12	887,301	704,597	2,411	1,874
Sep-12	564,609	608,426	1,857	1,463
Oct-12	544,848	455,152	1,481	1,211
Nov-12	539,505	517,605	1,606	1,348
Dec-12	639,722	745,957	1,999	1,759
Jan-13	730,322	744,888	2,075	1,900
Feb-13	621,688	609,557	1,943	1,732
Mar-13	546,456	596,621	1,626	1,462
Apr-13	474,852	431,563	1,349	1,173
May-13	485,816	456,466	1,380	1,164
Jun-13	645,637	620,844	2,018	1,552
Jul-13	851,072	751,211	2,418	1,916
Aug-13	861,894	728,519	2,449	1,858
Sep-13	576,046	604,530	1,800	1,511
Oct-13	541,895	470,424	1,473	1,251
Nov-13	509,990	560,064	1,594	1,400
Dec-13	664,146	732,980	1,977	1,797
Jan-14	729,063	749,882	2,071	1,913
Feb-14	620,277	614,546	1,938	1,746
Mar-14	538,958	608,883	1,604	1,492
Apr-14	475,534	437,242	1,351	1,188
May-14	443,915	490,166	1,321	1,201
Jun-14	618,823	590,473	1,842	1,538
Jul-14	819,986	718,396	2,330	1,833
Aug-14	778,408	750,678	2,317	1,840
Sep-14	568,863	559,665	1,693	1,457
Oct-14	512,001	450,221	1,391	1,197
Nov-14	455,412	566,006	1,498	1,361
Dec-14	669,902	674,459	1,903	1,721
Jan-15	657,019	752,875	1,955	1,845
Feb-15	586,195	592,176	1,832	1,682
Mar-15	542,051	556,137	1,540	1,419
Apr-15	458,819	418,509	1,303	1,137
May-15	416,994	498,614	1,303	1,176

Contract Month	Total Load (MWh)		Average Load	
	On Peak	Off Peak	On Peak	Off Peak
Jun-15	636,245	550,966	1,808	1,497
Jul-15	832,619	679,378	2,263	1,807
Aug-15	746,792	753,760	2,223	1,847
Sep-15	571,213	536,574	1,700	1,397
Oct-15	484,226	457,732	1,376	1,168
Nov-15	473,391	523,438	1,479	1,309
Dec-15	659,088	651,100	1,872	1,661
Jan-16	616,996	779,781	1,928	1,839
Feb-16	606,905	599,704	1,806	1,666
Mar-16	570,996	518,415	1,552	1,379
Apr-16	435,227	433,538	1,295	1,129
May-16	442,638	464,423	1,317	1,138
Jun-16	623,348	554,461	1,771	1,507
Jul-16	738,963	762,461	2,309	1,798
Aug-16	816,321	673,333	2,218	1,791
Sep-16	569,542	529,306	1,695	1,378
Oct-16	466,491	466,073	1,388	1,142
Nov-16	494,352	492,303	1,471	1,282
Dec-16	626,041	671,177	1,863	1,645
Jan-17	655,090	725,483	1,950	1,778
Feb-17	577,371	575,713	1,804	1,636
Mar-17	561,342	513,746	1,525	1,366
Apr-17	411,815	447,714	1,287	1,119
May-17	466,835	432,392	1,326	1,103

Updated Attachment E: Ameren Off-Peak Contract Volumes to Secure in 2012

Off Peak Contract Volumes to Secure (MW)							
Contract Month	Projected Volumes (MW)	Swap Volume (MW)	2010 Portfolio Volume (MW)	2011 Portfolio Volume (MW)	LT Wind Portfolio Volume (MW)	Residual Volume (MW)	2012 IPA Procurement (MW)
Jun-12	1,510	1,000	0	150	50	310	300
Jul-12	1,930	1,000	0	450	38	442	450
Aug-12	1,874	1,000	0	400	52	422	400
Sep-12	1,463	1,000	0	200	46	217	200
Oct-12	1,211	1,000	0	0	86	125	100
Nov-12	1,348	1,000	0	50	97	201	200
Dec-12	1,759	1,000	0	300	67	392	400
Jan-13	1,900	0	750	250	86	814	800
Feb-13	1,732	0	700	250	79	703	700
Mar-13	1,462	0	600	500	92	270	250
Apr-13	1,173	0	500	450	98	125	100
May-13	1,164	0	500	450	80	134	150
Jun-13	1,552	0	0	550	48	954	500
Jul-13	1,916	0	0	700	40	1,176	600
Aug-13	1,858	0	0	700	50	1,108	550
Sep-13	1,511	0	0	600	48	863	400
Oct-13	1,251	0	0	500	86	665	300
Nov-13	1,400	0	0	500	93	807	400
Dec-13	1,797	0	0	650	69	1,078	550
Jan-14	1,913	0	0	700	86	1,127	550
Feb-14	1,746	0	0	650	79	1,017	500
Mar-14	1,492	0	0	550	92	850	400
Apr-14	1,188	0	0	450	98	640	300
May-14	1,201	0	0	450	77	674	300
Jun-14	1,538	0	0	0	50	1,488	500
Jul-14	1,833	0	0	0	40	1,793	600
Aug-14	1,840	0	0	0	48	1,792	600
Sep-14	1,457	0	0	0	50	1,407	450
Oct-14	1,197	0	0	0	86	1,111	350
Nov-14	1,361	0	0	0	89	1,272	400
Dec-14	1,721	0	0	0	72	1,649	550
Jan-15	1,845	0	0	0	82	1,763	550
Feb-15	1,682	0	0	0	79	1,603	500
Mar-15	1,419	0	0	0	96	1,323	400
Apr-15	1,137	0	0	0	98	1,039	300
May-15	1,176	0	0	0	74	1,102	350

Off Peak Contract Volumes to Secure (MW)							
Contract Month	Projected Volumes (MW)	Swap Volume (MW)	2010 Portfolio Volume (MW)	2011 Portfolio Volume (MW)	LT Wind Portfolio Volume (MW)	Residual Volume (MW)	2012 IPA Procurement (MW)
Jun-15	1,497	0	0	0	53	1,444	0
Jul-15	1,807	0	0	0	41	1,766	0
Aug-15	1,847	0	0	0	48	1,799	0
Sep-15	1,397	0	0	0	50	1,347	0
Oct-15	1,168	0	0	0	82	1,086	0
Nov-15	1,309	0	0	0	93	1,216	0
Dec-15	1,661	0	0	0	72	1,589	0
Jan-16	1,839	0	0	0	79	1,760	0
Feb-16	1,666	0	0	0	78	1,588	0
Mar-16	1,379	0	0	0	100	1,279	0
Apr-16	1,129	0	0	0	94	1,035	0
May-16	1,138	0	0	0	77	1,061	0
Jun-16	1,507	0	0	0	53	1,454	0
Jul-16	1,798	0	0	0	37	1,761	0
Aug-16	1,791	0	0	0	52	1,739	0
Sep-16	1,378	0	0	0	50	1,328	0
Oct-16	1,142	0	0	0	79	1,063	0
Nov-16	1,282	0	0	0	97	1,185	0
Dec-16	1,645	0	0	0	69	1,576	0
Jan-17	1,778	0	0	0	82	1,696	0
Feb-17	1,636	0	0	0	79	1,557	0
Mar-17	1,366	0	0	0	100	1,266	0
Apr-17	1,119	0	0	0	90	1,029	0
May-17	1,103	0	0	0	80	1,023	0

Updated Attachment F: Ameren On-Peak Contract Volumes to Secure in 2012

Peak Contract Volumes to Secure (MW)							
Contract Month	Projected Volumes (MW)	Swap Volume (MW)	2010 Portfolio Volume (MW)	2011 Portfolio Volume (MW)	LT Wind Portfolio Volume (MW)	Residual Volume (MW)	2012 IPA Procurement (MW)
Jun-12	2,044	1,000	0	500	45	499	500
Jul-12	2,441	1,000	0	750	29	662	650
Aug-12	2,411	1,000	0	800	29	582	600
Sep-12	1,857	1,000	0	350	46	461	450
Oct-12	1,481	1,000	0	100	71	310	300
Nov-12	1,606	1,000	0	200	85	321	300
Dec-12	1,999	1,000	0	400	77	522	500
Jan-13	2,075	0	800	750	78	447	450
Feb-13	1,943	0	750	700	72	421	400
Mar-13	1,626	0	650	550	83	343	350
Apr-13	1,349	0	550	500	90	209	200
May-13	1,380	0	550	550	66	214	200
Jun-13	2,018	0	0	750	47	1,221	600
Jul-13	2,418	0	0	850	28	1,540	800
Aug-13	2,449	0	0	900	30	1,519	800
Sep-13	1,800	0	0	650	44	1,106	550
Oct-13	1,473	0	0	550	71	852	400
Nov-13	1,594	0	0	550	89	955	500
Dec-13	1,977	0	0	700	74	1,203	600
Jan-14	2,071	0	0	750	78	1,243	600
Feb-14	1,938	0	0	700	72	1,166	600
Mar-14	1,604	0	0	600	83	921	450
Apr-14	1,351	0	0	500	90	761	350
May-14	1,321	0	0	550	70	701	300
Jun-14	1,842	0	0	0	45	1,797	600
Jul-14	2,330	0	0	0	28	2,302	800
Aug-14	2,317	0	0	0	32	2,285	800
Sep-14	1,693	0	0	0	42	1,651	550
Oct-14	1,391	0	0	0	71	1,320	400
Nov-14	1,498	0	0	0	93	1,405	450
Dec-14	1,903	0	0	0	70	1,833	600
Jan-15	1,955	0	0	0	82	1,873	600
Feb-15	1,832	0	0	0	72	1,760	550
Mar-15	1,540	0	0	0	79	1,461	450
Apr-15	1,303	0	0	0	90	1,213	350
May-15	1,303	0	0	0	73	1,230	400

Peak Contract Volumes to Secure (MW)							
Contract Month	Projected Volumes (MW)	Swap Volume (MW)	2010 Portfolio Volume (MW)	2011 Portfolio Volume (MW)	LT Wind Portfolio Volume (MW)	Residual Volume (MW)	2012 IPA Procurement (MW)
Jun-15	1,808	0	0	0	43	1,765	0
Jul-15	2,263	0	0	0	27	2,236	0
Aug-15	2,223	0	0	0	32	2,191	0
Sep-15	1,700	0	0	0	42	1,658	0
Oct-15	1,376	0	0	0	74	1,302	0
Nov-15	1,479	0	0	0	89	1,390	0
Dec-15	1,872	0	0	0	70	1,802	0
Jan-16	1,928	0	0	0	86	1,842	0
Feb-16	1,806	0	0	0	69	1,737	0
Mar-16	1,552	0	0	0	76	1,476	0
Apr-16	1,295	0	0	0	94	1,201	0
May-16	1,317	0	0	0	70	1,247	0
Jun-16	1,771	0	0	0	43	1,728	0
Jul-16	2,309	0	0	0	31	2,278	0
Aug-16	2,218	0	0	0	29	2,189	0
Sep-16	1,695	0	0	0	42	1,653	0
Oct-16	1,388	0	0	0	78	1,310	0
Nov-16	1,471	0	0	0	85	1,386	0
Dec-16	1,863	0	0	0	74	1,789	0
Jan-17	1,950	0	0	0	82	1,868	0
Feb-17	1,804	0	0	0	72	1,732	0
Mar-17	1,525	0	0	0	76	1,449	0
Apr-17	1,287	0	0	0	99	1,188	0
May-17	1,326	0	0	0	66	1,260	0

Attachment G: Commonwealth Edison Projected Rate Class Volumes

Contract Month	Projected Monthly Volume Requirements									
	SF MWh	MF MWh	SFSH MWh	MFSH MWh	WH MWh	Small MWh	Condo MWh	DD MWh	GL MWh	Total MWh
12-Jun	1,803,202	393,843	42,644	94,682	34,690	465,273	17,028	8,039	1,245	2,860,645
12-Jul	2,320,581	504,385	42,517	101,391	37,632	497,643	18,675	8,252	1,278	3,532,353
12-Aug	2,087,645	466,960	37,320	92,188	37,017	487,674	18,756	8,774	1,359	3,237,692
12-Sep	1,295,555	298,458	24,966	62,012	30,841	416,476	16,362	8,845	1,370	2,154,885
12-Oct	1,042,736	242,638	28,565	62,892	28,656	393,326	15,911	9,795	1,517	1,826,036
12-Nov	986,915	222,164	43,343	87,775	25,399	365,654	15,440	9,944	1,540	1,758,172
12-Dec	1,182,212	252,932	66,506	142,653	27,613	388,652	19,947	10,530	1,631	2,092,677
13-Jan	1,165,345	244,425	75,734	174,669	28,356	393,625	20,659	10,520	1,630	2,114,964
13-Feb	939,389	210,516	65,694	153,063	25,043	342,310	18,372	9,050	1,402	1,764,839
13-Mar	913,849	207,920	58,040	133,554	25,905	347,033	19,194	9,297	1,440	1,716,232
13-Apr	787,293	182,223	41,135	92,059	23,748	316,326	15,159	8,639	1,338	1,467,920
13-May	843,146	197,735	30,639	68,662	24,785	324,110	15,977	8,613	1,334	1,515,001
13-Jun	1,188,910	267,556	28,307	66,659	26,267	339,415	16,999	8,214	1,272	1,943,599
13-Jul	1,559,125	347,813	28,656	71,794	28,826	368,216	18,814	8,494	1,316	2,433,054
13-Aug	1,428,298	326,542	25,513	65,511	28,509	359,310	18,745	8,965	1,389	2,262,781
13-Sep	965,965	226,493	18,522	47,256	24,828	310,762	16,526	9,121	1,413	1,620,885
13-Oct	838,933	198,266	22,794	51,525	23,857	292,533	16,021	10,056	1,558	1,455,544
13-Nov	908,371	207,362	39,515	82,060	22,620	276,669	15,459	10,136	1,570	1,563,763
13-Dec	1,108,440	240,086	61,687	135,507	25,011	298,000	20,197	10,829	1,677	1,901,434
14-Jan	1,091,368	230,653	69,736	164,451	25,734	304,096	20,859	10,790	1,671	1,919,356
14-Feb	881,848	198,850	60,580	144,168	22,820	267,055	18,528	9,292	1,439	1,604,581
14-Mar	860,803	197,018	53,698	126,159	23,732	273,379	19,365	9,567	1,482	1,565,202
14-Apr	743,436	173,140	38,165	87,201	21,865	251,754	15,292	8,906	1,379	1,341,139
14-May	796,353	188,135	28,499	65,167	22,803	259,425	16,023	8,841	1,369	1,386,615
14-Jun	1,147,001	260,021	26,897	64,613	24,525	275,901	17,204	8,505	1,317	1,825,984
14-Jul	1,506,992	338,599	27,278	69,701	26,913	299,723	18,938	8,745	1,355	2,298,242
14-Aug	1,376,903	316,939	24,214	63,400	26,645	293,242	18,787	9,181	1,422	2,130,733
14-Sep	938,903	221,565	17,721	46,087	23,577	258,136	16,741	9,427	1,460	1,533,617
14-Oct	812,532	193,361	21,769	50,114	22,668	243,317	16,151	10,329	1,600	1,371,840
14-Nov	878,125	201,720	37,639	79,590	21,480	230,643	15,496	10,341	1,602	1,476,637
14-Dec	1,089,183	237,228	59,686	133,473	24,165	253,180	20,487	11,149	1,727	1,830,276
15-Jan	1,061,055	225,216	66,688	160,054	24,730	258,138	21,003	11,037	1,710	1,829,631
15-Feb	860,611	194,859	58,142	140,819	22,057	228,886	18,727	9,560	1,481	1,535,143
15-Mar	844,365	194,099	51,813	123,882	23,119	236,763	19,689	9,913	1,535	1,505,177
15-Apr	724,116	169,458	36,583	85,068	21,216	218,010	15,458	9,196	1,424	1,280,529
15-May	772,583	183,495	27,223	63,355	22,042	224,761	16,103	9,091	1,408	1,320,062
15-Jun	1,130,897	257,820	26,119	63,865	23,975	242,708	17,448	8,821	1,366	1,773,020
15-Jul	1,482,114	334,925	26,425	68,732	26,220	264,079	19,104	9,019	1,397	2,232,014
15-Aug	1,351,440	312,851	23,408	62,390	26,018	260,183	18,956	9,461	1,465	2,066,174
15-Sep	915,894	217,351	17,026	45,075	23,090	230,944	16,911	9,716	1,505	1,477,512
15-Oct	785,968	188,073	20,733	48,595	22,138	218,097	16,239	10,583	1,639	1,312,065
15-Nov	860,613	198,722	36,301	78,163	21,253	210,464	15,757	10,688	1,655	1,433,616

Attachment G: Commonwealth Edison Projected Rate Class Volumes

15-Dec	1,063,681	232,767	57,330	130,554	23,839	231,714	20,727	11,453	1,774	1,773,837
16-Jan	1,035,980	220,819	64,396	157,183	24,234	235,722	21,108	11,249	1,742	1,772,433
16-Feb	880,453	199,937	58,788	144,621	22,616	218,865	19,691	10,184	1,578	1,556,732
16-Mar	834,838	192,286	50,608	122,743	22,880	219,785	19,981	10,231	1,585	1,474,937
16-Apr	708,210	165,922	35,336	83,248	20,756	200,938	15,508	9,412	1,458	1,240,788
16-May	767,267	182,288	26,692	62,861	21,816	210,216	16,343	9,410	1,458	1,298,352
16-Jun	1,122,462	255,742	25,586	63,231	23,559	226,377	17,578	9,070	1,405	1,745,009
16-Jul	1,462,895	330,044	25,729	67,554	25,519	245,120	19,062	9,189	1,423	2,186,535
16-Aug	1,358,368	313,592	23,196	62,331	25,781	246,530	19,256	9,789	1,516	2,060,357
16-Sep	909,672	215,037	16,661	44,416	22,693	218,103	17,039	9,972	1,545	1,455,138
16-Oct	775,755	184,679	20,147	47,491	21,648	205,776	16,279	10,800	1,673	1,284,247
16-Nov	860,733	197,450	35,714	77,237	21,010	201,440	15,972	11,004	1,704	1,422,263
16-Dec	1,055,651	229,177	55,921	127,744	23,330	220,660	20,804	11,664	1,807	1,746,756
17-Jan	1,036,202	219,834	63,770	155,749	23,921	226,443	21,374	11,512	1,783	1,760,588
17-Feb	840,188	189,875	55,535	136,700	21,289	201,159	19,014	9,989	1,547	1,475,296
17-Mar	829,808	190,216	49,799	120,853	22,443	209,783	20,105	10,441	1,617	1,455,065
17-Apr	698,765	162,946	34,519	81,373	20,211	190,461	15,492	9,560	1,481	1,214,807
17-May	767,423	181,505	26,437	62,298	21,491	201,384	16,517	9,665	1,497	1,288,219

Attachment H: Commonwealth Edison Off -Peak Total and Average Load to Secure

Contract Month	Total Load (MWh)		Average Load (MW)	
	On-Peak	Off-Peak	On-Peak	Off-Peak
12-Jun	1,483,123	1,377,522	4,414	3,587
12-Jul	1,783,342	1,749,011	5,308	4,287
12-Aug	1,773,935	1,463,757	4,820	3,893
12-Sep	999,298	1,155,587	3,287	2,778
12-Oct	982,889	843,147	2,671	2,242
12-Nov	889,563	868,610	2,648	2,262
12-Dec	969,881	1,122,796	3,031	2,648
13-Jan	1,065,498	1,049,465	3,027	2,677
13-Feb	890,543	874,296	2,783	2,484
13-Mar	825,734	890,498	2,458	2,183
13-Apr	771,098	696,822	2,191	1,894
13-May	779,607	735,393	2,215	1,876
13-Jun	957,737	985,862	2,993	2,465
13-Jul	1,284,990	1,148,064	3,651	2,929
13-Aug	1,188,879	1,073,902	3,377	2,740
13-Sep	792,561	828,324	2,477	2,071
13-Oct	780,887	674,656	2,122	1,794
13-Nov	748,014	815,750	2,338	2,039
13-Dec	919,251	982,183	2,736	2,407
14-Jan	962,107	957,250	2,733	2,442
14-Feb	804,964	799,617	2,516	2,272
14-Mar	748,042	817,161	2,226	2,003
14-Apr	700,108	641,031	1,989	1,742
14-May	676,392	710,223	2,013	1,741
14-Jun	939,364	886,620	2,796	2,309
14-Jul	1,213,357	1,084,885	3,447	2,768
14-Aug	1,068,561	1,062,173	3,180	2,603
14-Sep	787,188	746,429	2,343	1,944
14-Oct	733,187	638,654	1,992	1,699
14-Nov	668,563	808,073	2,199	1,942
14-Dec	922,539	907,737	2,621	2,316
15-Jan	873,949	955,682	2,601	2,342
15-Feb	770,530	764,613	2,408	2,172
15-Mar	751,617	753,560	2,135	1,922
15-Apr	665,177	615,352	1,890	1,672
15-May	609,781	710,281	1,906	1,675
15-Jun	951,758	821,262	2,704	2,232
15-Jul	1,228,457	1,003,557	3,338	2,669
15-Aug	1,032,532	1,033,642	3,073	2,533
15-Sep	756,199	721,313	2,251	1,878
15-Oct	668,722	643,343	1,900	1,641
15-Nov	679,968	753,648	2,125	1,884

Attachment H: Commonwealth Edison Off -Peak Total and Average Load to Secure

15-Dec	893,782	880,055	2,539	2,245
16-Jan	805,492	966,941	2,517	2,281
16-Feb	792,844	763,889	2,360	2,122
16-Mar	767,937	707,000	2,087	1,880
16-Apr	613,452	627,337	1,826	1,634
16-May	629,918	668,434	1,875	1,638
16-Jun	943,987	801,023	2,682	2,177
16-Jul	1,052,468	1,134,067	3,289	2,675
16-Aug	1,133,056	927,302	3,079	2,466
16-Sep	736,883	718,256	2,193	1,870
16-Oct	624,403	659,845	1,858	1,617
16-Nov	706,060	716,203	2,101	1,865
16-Dec	838,785	907,971	2,496	2,225
17-Jan	837,083	923,505	2,491	2,263
17-Feb	737,916	737,380	2,306	2,095
17-Mar	754,320	700,745	2,050	1,864
17-Apr	572,001	642,806	1,788	1,607
17-May	654,628	633,591	1,860	1,616

Attachment I: Commonwealth Edison Off Peak Load to Secure in 2012

Contract Month	Off-Peak Contract Volumes to Secure (MW)					
	Projected Volume (MW)	Swap Volumes (MW)	2011 IPA Procurement (MW)	Long-Term Renewable Energy (MW)	Residual Volumes (MW)	2012 IPA Procurement (MW)
12-Jun	3,587	3,000	-	106	481	500
12-Jul	4,287	3,000	600	80	607	600
12-Aug	3,893	3,000	300	109	484	500
12-Sep	2,778	3,000	-	97	-319	0
12-Oct	2,242	3,000	-	180	-938	0
12-Nov	2,262	3,000	-	204	-942	0
12-Dec	2,648	3,000	-	140	-492	0
13-Jan	2,677	3,000	-	180	-503	0
13-Feb	2,484	3,000	-	167	-683	0
13-Mar	2,183	3,000	-	194	-1,011	0
13-Apr	1,894	3,000	-	205	-1,311	0
13-May	1,876	3,000	-	168	-1,292	0
13-Jun	2,465	-	1,250	102	1,113	350
13-Jul	2,929	-	1,800	83	1,046	150
13-Aug	2,740	-	1,650	105	985	150
13-Sep	2,071	-	1,050	101	920	300
13-Oct	1,794	-	1,100	180	514	0
13-Nov	2,039	-	1,250	196	593	0
13-Dec	2,407	-	1,250	146	1,011	300
14-Jan	2,442	-	1,300	180	962	250
14-Feb	2,272	-	1,400	167	705	0
14-Mar	2,003	-	1,250	194	559	0
14-Apr	1,742	-	1,100	205	437	0
14-May	1,741	-	1,100	162	479	0
14-Jun	2,309	-	-	106	2,203	700
14-Jul	2,768	-	-	83	2,685	900
14-Aug	2,603	-	-	101	2,502	800
14-Sep	1,944	-	-	105	1,839	600
14-Oct	1,699	-	-	180	1,519	400
14-Nov	1,942	-	-	188	1,754	500
14-Dec	2,316	-	-	152	2,164	650
15-Jan	2,342	-	-	173	2,169	650
15-Feb	2,172	-	-	167	2,005	600
15-Mar	1,922	-	-	202	1,720	450
15-Apr	1,672	-	-	205	1,467	400
15-May	1,675	-	-	156	1,519	450
15-Jun	2,232	-	-	106	2,126	0
15-Jul	2,669	-	-	83	2,586	0
15-Aug	2,533	-	-	101	2,432	0
15-Sep	1,878	-	-	105	1,773	0

Attachment I: Commonwealth Edison Off Peak Load to Secure in 2012

15-Oct	1,641	-	-	180	1,461	0
15-Nov	1,884	-	-	188	1,696	0
15-Dec	2,245	-	-	152	2,093	0
16-Jan	2,281	-	-	173	2,108	0
16-Feb	2,122	-	-	167	1,955	0
16-Mar	1,880	-	-	202	1,678	0
16-Apr	1,634	-	-	205	1,429	0
16-May	1,638	-	-	156	1,482	0
16-Jun	2,177	-	-	106	2,071	0
16-Jul	2,675	-	-	83	2,592	0
16-Aug	2,466	-	-	101	2,365	0
16-Sep	1,870	-	-	105	1,765	0
16-Oct	1,617	-	-	180	1,437	0
16-Nov	1,865	-	-	188	1,677	0
16-Dec	2,225	-	-	152	2,073	0
17-Jan	2,263	-	-	173	2,090	0
17-Feb	2,095	-	-	167	1,928	0
17-Mar	1,864	-	-	202	1,662	0
17-Apr	1,607	-	-	205	1,402	0
17-May	1,616	-	-	156	1,460	0

Attachment J: Commonwealth Edison Peak Load to Secure in 2012

Contract Month	Peak Contract Volumes to Secure (MW)					
	Projected Volume (MW)	Swap Volumes (MW)	2011 IPA Procurement (MW)	Long-Term Renewable Energy (MW)	Residual Volumes (MW)	2012 IPA Procurement (MW)
12-Jun	4,414	3,000	600	94	720	700
12-Jul	5,308	3,000	1,500	61	747	750
12-Aug	4,820	3,000	1,150	61	609	600
12-Sep	3,287	3,000		97	190	200
12-Oct	2,671	3,000		150	-479	0
12-Nov	2,648	3,000		178	-530	0
12-Dec	3,031	3,000		162	-131	0
13-Jan	3,027	3,000		164	-137	0
13-Feb	2,783	3,000		152	-369	0
13-Mar	2,458	3,000		174	-716	0
13-Apr	2,191	3,000		188	-997	0
13-May	2,215	3,000		187	-972	0
13-Jun	2,993	-	1,800	99	1,094	200
13-Jul	3,651	-	2,250	59	1,342	250
13-Aug	3,377	-	2,100	63	1,214	200
13-Sep	2,477	-	1,300	92	1,085	350
13-Oct	2,122	-	1,350	150	622	0
13-Nov	2,338	-	1,450	187	701	0
13-Dec	2,736	-	1,750	155	831	0
14-Jan	2,733	-	1,500	164	1,069	250
14-Feb	2,516	-	1,600	152	764	0
14-Mar	2,226	-	1,400	174	652	0
14-Apr	1,989	-	1,300	188	501	0
14-May	2,013	-	1,350	196	467	0
14-Jun	2,796	-	-	94	2,702	900
14-Jul	3,447	-	-	59	3,388	1150
14-Aug	3,180	-	-	66	3,114	1050
14-Sep	2,343	-	-	87	2,256	750
14-Oct	1,992	-	-	150	1,842	550
14-Nov	2,199	-	-	197	2,002	550
14-Dec	2,621	-	-	148	2,473	750
15-Jan	2,601	-	-	172	2,429	750
15-Feb	2,408	-	-	152	2,256	700
15-Mar	2,135	-	-	166	1,969	600
15-Apr	1,890	-	-	188	1,702	450
15-May	1,906	-	-	206	1,700	450
15-Jun	2,704	-	-	94	2,610	0
15-Jul	3,338	-	-	59	3,279	0
15-Aug	3,073	-	-	66	3,007	0
15-Sep	2,251	-	-	87	2,164	0

Attachment J: Commonwealth Edison Peak Load to Secure in 2012

15-Oct	1,900	-	-	150	1,750	0
15-Nov	2,125	-	-	197	1,928	0
15-Dec	2,539	-	-	148	2,391	0
16-Jan	2,517	-	-	172	2,345	0
16-Feb	2,360	-	-	152	2,208	0
16-Mar	2,087	-	-	166	1,921	0
16-Apr	1,826	-	-	188	1,638	0
16-May	1,875	-	-	206	1,669	0
16-Jun	2,682	-	-	94	2,588	0
16-Jul	3,289	-	-	59	3,230	0
16-Aug	3,079	-	-	66	3,013	0
16-Sep	2,193	-	-	87	2,106	0
16-Oct	1,858	-	-	150	1,708	0
16-Nov	2,101	-	-	197	1,904	0
16-Dec	2,496	-	-	148	2,348	0
17-Jan	2,491	-	-	172	2,319	0
17-Feb	2,306	-	-	152	2,154	0
17-Mar	2,050	-	-	166	1,884	0
17-Apr	1,788	-	-	188	1,600	0
17-May	1,860	-	-	206	1,654	0