ATTACHMENT A: IPA PROCUREMENT PLAN

State of Illinois
Pat Quinn, Governor

ILLINOIS POWER AGENCY

Draft Power Procurement Plan
September 29, 2010

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Executive Summary

Pursuant to Public Act 095-0481[1], the Illinois Power Agency ("IPA" of "Agency") submits this proposed electricity procurement plan (the "Draft Plan") designed "to ensure adequate, reliable, affordable, efficient, and environmentally sustainable electric service at the lowest total cost over time…"[2]

This document and its attachments comprise the third Draft Plan prepared by the IPA. The IPA Act requires that a Draft Plan and a Final Plan be prepared and submitted annually.

This Draft Plan's purpose is to detail a procurement approach that will secure electricity commodity and associated transmission services, plus required renewable energy assets to meet the supply needs and obligations of the Renewable Portfolio Standard of eligible retail customers served by Ameren Illinois Utilities ("Ameren") and Commonwealth Edison Company ("ComEd" and jointly the "Utilities").

This Plan outlines a procurement strategy for the period of June 2011 through May 2016 based on detailed 5-year demand forecasts provided by the Utilities. Because existing contracts are in place for a significant portion of the load needed to meet consumers' electricity needs over the near term, procurement activities considered in this Draft Plan are limited to meeting the residual consumer demand not covered by those contracts.

Procurement Approach. The IPA proposes to maintain the core elements of the procurement approach used in the last three procurement cycles. Those elements are:

- **Request for Proposals based solicitations.** The procurement events will be facilitated through a two-stage process oriented around a Request for Proposal ("RFP") for each wholesale product sought. The first stage of the RFP will establish a pool of qualified bidders; the second stage will solicit bids for scheduled volumes of wholesale product. The resources sought through the RFP events will be:
  - **Ameren –** Energy, Capacity, Demand Response, and Renewable Energy Resources
  - **ComEd –** Energy, Demand Response, and Renewable Energy Resources
- **Timing.** The IPA proposes to hold primary procurement events during the spring of 2011 seeking the volumes of wholesale products identified in this Draft Plan. Further, the IPA proposes that optional procurements of up to an additional 10% of projected energy portfolio requirements in any month for the second and third planning year by the Final Plan that is below the 100% subscription level. The optional procurements would be triggered only when market indices demonstrate that prices for energy supply contracts for the targets months are at least 10% below the average weighted price of fixed price contracts already secured by the Utilities for those months and such prices are below the prices for the most recently completed planning year procurement event. The optional procurements would be limited to participation by bidders qualified in and the terms and conditions agreed to in the spring 2011 solicitation, and allowed only with the authorization of the Commission.
- **Procurement Administrators.** The IPA will retain the services of Procurement Administrator(s) through a Request for Qualifications ("RFQ") and subsequent RFPs. Per recommendations made to the IPA, the RFQ and RFP will solicit offers from bidders seeking to provide comprehensive Administrator responsibilities for one or both Utility procurement events (i.e. Power, Capacity, and Renewable Energy Resources for Ameren, and/or Power, Demand Response in lieu of Capacity, and Renewable Energy Resources for ComEd), as well as offers to administer single wholesale product solicitations for both Utilities (i.e. Power Resources for both Ameren and ComEd, Renewable Energy Resources for both Ameren and ComEd).

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

- **Fixed Price for fixed volumes.** The RFPs for wholesale products will seek offers for fixed volumes at fixed prices.

- **Products.** The IPA proposes to seek bids for wholesale products for the following periods:

  - **Energy Supply Resources –** Supply will be sought for the Ameren and ComEd loads on a laddered three-year forward basis. The IPA proposes to allow Energy Efficiency from programs that are evaluated in a manner equivalent to the existing Energy Efficiency Portfolio Standards programs administered by the Utilities to be treated as an energy supply resource. Price for the products would be procured after the spring 2011 solicitations for the more traditional physical and swap products through a competitive solicitation. The combined costs of traditional energy, capacity and renewable energy assets within the IPA portfolio after the spring 2011 procurement events will be used to develop a cost-effectiveness benchmark for the energy efficiency procurements. The IPA will not procure resources that are required to meet the Energy Efficiency Portfolio Standard.

  - **Capacity Resources –** Capacity Resources for ComEd will be delivered 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.

  - **Demand Response Resources** – Consistent with 220 ILCS 5/16-111.5(b)(3)(ii), the IPA proposes that solicitations seeking cost-effective demand response assets occur for both Utilities. The IPA notes that as statute does not require or infer that these assets are procured in lieu of capacity, that they will be sought independent of the Capacity Resource plans specified in this Plan.

  - **Renewable Energy Resources** – Renewable Energy Credits ("REC") for a single compliance year (June 2011 through May 2012). The IPA proposes to continue the consolidation of REC procurement processes and procedures started in 2010, and seek to unify standard terms and conditions between Ameren and ComEd with regard to REC contracts. Therefore, the utilities' REC contracts should include (1) collateral requirements that equal 10% of remaining contract value; and (2) unsecured credit limits for creditworthy REC suppliers.

- **Public comment and workshops.** The IPA held public meetings seeking comment on the Draft Plan.

Portfolio Design. To achieve low and stable prices when acquiring electricity in a market where prices change constantly (and sometimes dramatically) is the IPA's greatest challenge, particularly when the load is not fully stable. Designing the portfolio requires understanding the variables that drive price and load fluctuation, and assessing how those variables affect price risk. After completing its portfolio design exercise, the IPA proposes the schedule of purchases of wholesale products to meet the needs of eligible customers.

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 and 2010 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 2010 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 and 2010 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.

Introduction and Overview

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:

> *(a)The Agency is authorized to do each of the following:*
>
> *(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.*[3]

This is the third Draft 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 2011 through May 2016. The Draft Plan applies to the following Utilities: AmerenCILCO, AmerenCIPS, AmerenIP ("Ameren"), and Commonwealth Edison ("ComEd" and jointly the "Utilities").

The IPA Act requires that the Draft 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*[4]

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

> *A procurement plan shall include each of the following components:*
>
> *(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;*

[3] 20 ILCS 3855/1-20.
[4] 220 ILCS 5/16-111.5(b).

(ii) the proposed mix of demand-response products for which contracts will be executed during the next year. The cost-effective demand-response measures shall be procured whenever the cost is lower than procuring comparable capacity products, provided that such products shall:

- *(A) be 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 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 requirements 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[5].*

This Draft Plan, as submitted, meets the requirements of the IPA Act.

A. Illinois Electricity Market 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.

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

SB 1592[6] 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 Draft Plan reflects these recent changes in 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.

The IPA procurement plans are designed to accommodate the electricity needs of customers who continue buying bundled service electricity from the Utilities. According to the latest published data for the Commission's Electric Switching Statistics – DASR reports (May 2010 for the Utilities), only 40.7% of the total electricity usage by ComEd and Ameren customers over the period was supplied through fixed price bundled utility service. Another 4.6% was delivered at Hourly Energy Pricing, and the remaining 55.7% delivered through ARES. According to those same reports, 99.9% of ComEd and Ameren residential customers remain on bundled rates.

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

- Public Act 094-1095 created the Office of Retail Market Development (ORMD) 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:
    - Rulemaking for Code Part 412. Workshops and rules drafting in support of provisions of Public Act 95-0700 (see below for more detail).
    - Launch of a website (www.PluginIllinois.org) in April 2010 to educate Illinois consumers on the options and benefits afforded by ARES.
    - Development of an Offer Comparison Website which will provide interested consumers with an unbiased comparison of the costs and benefits of multiple ARES offers.
    - Development of a Retail Choice and Referral Program designed to provide consumers with incentives to enter into a supply contract with qualified ARES.

[6] Public Act 095-0481

- Public Act 95-0700 requires the Utilities to offer to the ARES utility consolidated billing ("UCB"), the purchase of receivables ("POR") and the purchase of two billing cycles of uncollectible receivables ("POU"):
  - UCB allows for the electronic submittal of monthly ARES customer charges for power and energy to the utility which then places those charges, along with its delivery charges, on one single bill to the customer.
  - POR allows ARES to sell its receivables (the amount due to an ARES by a customer) to the Utility at a discount. The POR is designed to encourage ARES to not cherry-pick customers.
  - POU allows ARES to sell up to two billing cycles worth of uncollectible receivables to the Utility at a discount upon returning a customer back to the Utility
- Public Act 96-0176 allows municipal bodies to aggregate the load of eligible retail customers located within their jurisdiction and negotiate a retail electric contract with an ARES on their behalf.

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 of supporting competitive electricity markets will continue and strengthen, and that eligible retail consumers currently served through the IPA portfolio migrate towards ARES options.

B. Illinois Power Agency Planning Process Overview. This Draft 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 does not address supply needs or RPS compliance methods for hourly rate customers of the Utilities, or those customers taking service from ARES.

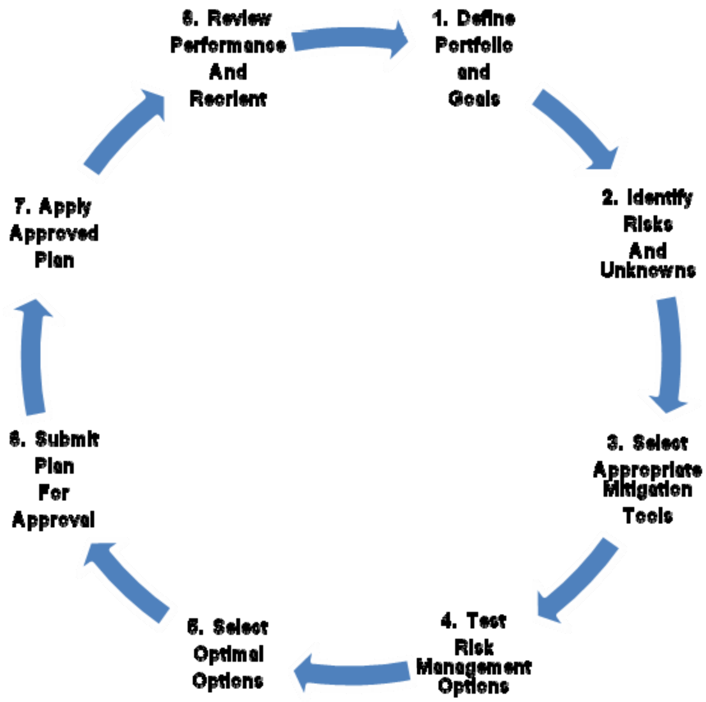
As noted above, the IPA must submit a Plan each year identifying projected loads for Eligible Retail Customers, and a plan for fulfilling those load requirements. Per the PUA, Eligible Retail Customers are defined as:

> *[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.*[7]

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.

[7] 220 ILCS 5/16-111.5(a).

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.
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 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 Plan is 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 A.

TABLE A: PROPOSED IPA PLAN SUBMISSION AND AUTHORIZATION SCHEDULE

Planning Activities	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10
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.
    a. The Ameren five-year projections were received by the IPA on July 15, 2010
    b. The ComEd five-year projections were received by the IPA on July 13, 2010

2. **IPA Prepares Draft Plan.** The IPA prepared a Draft Plan for submission to the Commission with proposals designed to meet the needs of customers purchasing electricity from the Utilities.

3. **IPA Submits Preliminary Plan.** The Preliminary Plan was made available to the public for comment on the ICC and IPA websites on September 15, 2010.

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. August 26, 2010 in Chicago at the ICC's offices at 160 N. LaSalle Street in the Main Hearing Room from 10 am to noon. A workshop was held that afternoon from 1:30-5pm in the same location to discuss this year's Draft Plan.
    b. August 31, 2010 in Springfield at the ICC's offices at 527 East Capital Avenue in the Main Hearing Room from 10 am to noon. A workshop was held that afternoon from 1:30-5pm in the same location to discuss this year's Draft Plan.

5. **Final Plan Submission to ICC.** This Final Plan was prepared by the IPA in consideration of the comments received during the public comment period.

6. **Objections Filing Period.** Objections to the Plan must be filed within five (5) days after the plan is filed with the ICC.

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 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 B below.

TABLE B: PROPOSED IPA PROCUREMENT EXECUTION SCHEDULE

Procurement Activities	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11
1. Procurement Administrator RFQ Issued	X								
2. Procurement Administrator RFP issued		X							
3. Procurement Administrator Selected		X							
4. RFP and systems developed									
5. RFP Released					X				
6. Procurement Event Preparation									
7. Procurement Events									
8. Supply Contracts Executed									
9. Procured Products Delivery Begins									

1. **Procurement Administrator RFQ Issued.** 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 first required step in retaining the services of a Procurement Administrator is the issuance of a Request for Qualifications followed by the IPA giving notice to interested parties of those firms considered as qualified by the IPA. Interested parties can object to the inclusion of specific firms based on certain criteria.

2. **Procurement Administrator RFP Issued.** The second step in retaining the services of one or more Procurement Administrators is the issuance of a Request for Proposals. The IPA intends to solicit offers from bidders seeking to provide comprehensive Administrator responsibilities for one or both Utility procurement events (i.e. Power, Capacity, and Renewable Energy Resources for Ameren, and/or Power and Renewable Energy Resources for ComEd), as well as offers to administer single wholesale product solicitations for both Utilities (i.e. Power Resources for both Ameren and ComEd, Renewable Energy Resources for both Ameren and ComEd). The ranking of the proposals will be based on the best value presented to the IPA.

3. **Procurement Administrator selected.** The IPA must inform the ICC and receive authorization of that selection prior to entering into a contract with the Procurement Administrator(s).

4. **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.[8]

5. **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.

6. **Procurement Event Preparation.** The Procurement Administrator will be required to establish methods and platforms to facilitate bidding on defined electricity products. The

[8] 220 ILCS 5/16-111.5(e).

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.

7. **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.

8. **Procured Products Delivery Begins.** Supply contracts secured through the spring 2011 procurement events will commence in June of 2011 (some contracts may be effective at a later date). These procured volumes will be in addition to those electricity supplies already secured via legacy contract sources from the swap contracts resulting from the 2007 rate settlement agreement, and the 2010 IPA procurement cycle.

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 and prices for those volumes is based on the IPA portfolio design. The IPA Act provides the priorities for the portfolio design are:

> *"… to ensure adequate, reliable, affordable, efficient, and environmentally sustainable electric service at the lowest total cost over time, taking into account any benefits of price stability."*[9]

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 rising 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.

A. 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."*[10]

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

[9] 220 ILCS 5/16-111.5(d)(4).
[10] 220 ILCS 5/16-111.5(b)(3)(v).

1. **Price Risk.** The portfolio is exposed to price risk on two 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. **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 review of the Illinois electricity market, 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 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 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 not taken hold in the broader Residential market in Illinois (see Tables C and D below). However, as noted in the above review of the Illinois electricity market, recent developments indicate that significant reductions to the barriers to retail competition in residential markets are on the near-term horizon.

TABLE C: DISTRIBUTION OF AMEREN CUSTOMERS UTILIZING ARES SERVICES

Supply Options Chosen by Customers of Ameren as of May 31, 2010				
Customer Supply Groups:	**Residential**	**Small C & I Accounts**	**Large C & I Accounts**	**Total**
Generally Defined As:		(Demand < 1 MW)	(Demand > 1 MW)	
Total Number of Customers	1,056,431	149,665	547	1,206,643
Taking Hourly Price Service from Ameren	9,218	609	57	9,884
Taking Fixed Price Supply Service from Ameren	1,047,101	122,616	6	1,169,723
Taking Supply Service from a Retail Electric Supplier (RES)	112	26,440	484	27,036
Percentage of Customers Receiving RES Service	**0.0106%**	**17.7%**	**88.5%**	**2.2%**
Total Monthly Customer Usage (MWH)	627,891	709,093	1,273,383	2,610,367
Of Hourly Price Service Customers	6,801	17,830	130,001	154,632
Of Ameren Fixed Price Supply Service Customers	621,029	287,938	583	909,550
Of RES Customers	61	403,325	1,142,799	1,546,185
Percentage of Usage Taking RES Supply Service	**0.0097%**	**56.9%**	**89.7%**	**59.2%**

TABLE D: DISTRIBUTION OF COMED CUSTOMERS UTILIZING ARES

Supply Options Chosen by Customers of ComEd as of May 31, 2010				
Customer Supply Groups	**Residential**	**Small C & I Accounts**	**Large C & I Accounts**	**Total**
Generally Defined As:		(Demand < 1 MW)	(Demand > 1 MW)	
Total Number of Customers	3,440,238	369,127	1,984	3,811,349
Taking Hourly Price Service from ComEd	9,664	4,032	152	13,848
Taking Fixed Price Supply Service from ComEd	3,430,355	311,903	5	3,742,263
Taking Supply Service from a Retail Electric Supplier (RES)	219	53,192	1,827	55,238
Percentage of Customers Receiving RES Service	**0.0064%**	**14.4%**	**92.1%**	**1.4%**
Total Monthly Customer Usage (MWH)	2,063,446	2,523,629	2,179,823	6,766,897
Of Hourly Price Service Customers	2,969	188,314	87,389	278,673
Of ComEd Fixed Price Supply Service Customers	2,060,319	844,681	599	2,905,600
Of RES Customers	157	1,490,633	2,091,835	3,582,625
Percentage of Usage Taking RES Supply Service	**0.0076%**	**59.1%**	**96.0%**	**52.9%**

While the scale and rate of migration away from the IPA portfolio is not known, a reference to statistics reported by the U.S. Department of Energy's Energy Information Administration the migration of natural gas customers away from bundled natural gas supply offered by Nicor, Peoples Gas, and North Shore indicates that some appetite for alternative energy supply does exist. Table E below conveys that in 2009 9.3% of eligible residential consumers received natural gas supply from Alternative Retail Gas Suppliers ("ARGS"). The IPA anticipates that higher migration rates are possible in electricity markets as tariff structure will allow ARES to make direct comparisons between their price offers and the annual fixed rate for energy available through the Utilities and sourced to the IPA portfolio.

TABLE E: ALTERNATIVE GAS SUPPLY PARTICIPATION RATES FOR PEOPLES GAS, NORTH SHORE GAS, AND NICOR

Participation in Alternative Gas Supply by Customer Class, December 2009						
Customer Type	2008 Customer Total	Eligible December 2009		Participating December 2009		
		Total	% of 2008 Customers	Total	% of 2009 Eligible	% of 2008 Customers
Residential	3,869,308	2,908,454	75.2	271,067	9.3	7
Commercial/Industrial*	322,155	254,183	78.9	49,558	19.5	15.4
Total	**4,191,463**	**3,162,637**	**75.5**	**320,625**	**10.1**	**7.6**

*All large commercial and industrial customers have the option of purchasing natural gas from suppliers other than LDCs. The "eligible" and "participating" commercial/industrial customers include all Nicor Gas commercial and industrial customers, but only small-volume commercial customers for Peoples Gas and North Shore Gas. Illinois had 298,418 commercial and 23,737 industrial customers in 2008.

Sources: **2008 Customer Total:** Energy Information Administration, *Natural Gas Annual 2008* (March 2010). **Eligibility and Participation:** Nicor Gas Company, Peoples Gas and Light Company, and North Shore Gas Company (February 2010).

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 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.

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 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.

Contracts entered into as a result of the procurement process shall be executed through one of the following methods:

1. International Swaps and Derivatives Association ("ISDA") agreement for financial instruments such as fixed/floating rate swaps; or
2. Central counterparty clearing for standardized financial instruments on exchange traded contracts; or
3. An Edison Electric Institute ("EEI") agreement for physical products.

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 as many as nine 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 procurement process, revised load projections from the Utilities were submitted in response to downward projections in load requirements due to economic weakness within the region.

   Similarly, 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.

   To mitigate the risk of price decline, the IPA recommends that the ICC allow for optional procurements for energy only. These optional procurements would be limited to only an additional 10% of projected portfolio requirements in any month for the second and third planning years covered by the Final Procurement Plan that is below the 100% subscription level. The optional procurements would be triggered only when market indices demonstrate that prices for energy supply contracts for the target months are at least 10% below the average weighted price of fixed price contracts already secured by the Utilities for those months and such prices are below the prices for the most recently completed planning year procurement event. The optional procurements would be limited to participation by bidders qualified in and the terms and conditions agreed to in the Spring 2011 solicitation, and allowed only with the authorization of the Commission. After the optional procurement event(s) for energy hedges, the maximum subscription quantity shall be 100% for year 1, 80% for year 2, 45% for year 3 and 0% for years 4 and 5.

5. **Fuel Costs.** Fuel costs present risk to the portfolio insofar as fuel costs are the primary drivers of generation costs. 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.

   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.

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.

   i. **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.

   ii. **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.

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, and higher integration costs associated with wind energy developments.

   Recent projections indicate plans for billions of dollars in transmission investments throughout the MISO and PJM regions. Some of the transmission system upgrades propose to extend transmission between wind generating regions in the western spans of the MISO region and larger population centers in the eastern reaches of MISO as well as PJM. Future transmission costs will be borne by MISO and PJM participants via tariff.

   The rapid development of wind-based renewable electricity generation in the PJM and MISO regions will likely cause upward pressure on transmission costs because wind facilities tend to be in remote locations that may not have adequate existing transmission to bring power to load centers. In addition, system operators will need to alter system operations to accommodate the intermittent nature of wind energy.

   Past estimates of costs relative to integrating wind assets into regional transmission portfolios range from as low as $2.11/MWh for 15% wind penetration within the portfolio to $4.41/MWh for a penetration level of 25%.[11] Some of these costs may be offset by contributions of wind assets towards system reliability and other ancillary services. Recently, the Bonnevile Power Authority issued a final decision for its 2010 rate case. In the final rate case decision, the Authority authorized charging wind generators a "Wind Integration Rate" of $1.29/kilowatt-month (approximately $5.70/MWh). The approved rate was substantially lower than the originally requested rate of $2.79/kilowatt-month (approximately $12.00/MWh). The purpose of the fee was to cover the costs associated with the higher load balancing costs associated with facilitating the variable nature of wind asset output. In return for the lower than originally requested fee, wind generators agreed to a first-ever curtailment arrangement.[12]

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[11] "Accommodating Wind's Natural Behavior", DeMeo et al, IEEE Power & Energy Magazine, November/ December 2007, page 62.

[12] http://www.transmission.bpa.gov/Business/Rates_and_Tariff/2009WindIntegRateCAse.cfm

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. 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.

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.

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 2011 – May 2016 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.

B. Modeling and Portfolio Design. 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 Draft Plan utilizes methods similar to those used by investors to manage market portfolio risks.

The Draft 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.

To establish a model portfolio for each Utility, a Monte Carlo model using Excel® and Crystal Ball® 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 the 2010 procurement cycle will supply portions of the IPA portfolio into the period covered by this Draft 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:

$$\textbf{Composite Metric} = \textbf{Square Root } [(SDA^2 + SDB^2 + SDC^2)/3]$$

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 2016 as of August 10, 2010. 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 2013, 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 allows the Monte Carlo simulation to vary 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. In addition, the model does factor for intentional oversubscription of planned volumes in summer months (July and August) and non-summer periods to investigate whether procuring more or less than 100% of net open requirements would reduce a model portfolio's risk.

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 typically 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. Replacement capacity appears to be planned, however many queue applicants are renewable energy generators with little to no baseload capacity value. 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.

Application of the Plan for the Utilities

Overview. Load projections that serve as the basis of this Draft Plan are supplied by the Utilities. The PUA requires:

> *"Beginning in 2008, each Illinois utility procuring power pursuant to this Section shall annually provide a range of load forecasts to the Illinois Power Agency by July 15 of each year, or such other date as may be required by the Commission or Agency. The load forecasts shall cover the 5-year procurement planning period for the next procurement plan and shall include hourly data representing a high-load, low-load and expected-load scenario for the load of the eligible retail customers. The utility shall provide supporting data and assumptions for each of the scenarios."*[13]

Consistent with the PUA, Ameren delivered load forecasts to the IPA on July 15, 2010 and ComEd delivered their forecasts on July 13. Per the request of the IPA, the Utilities also provided detailed descriptions of the statistical methods and assumptions underlying the projections. Copies of the Ameren and ComEd projection methodologies can be found in Attachments A and E to this Draft Plan.

[13] 220 ILCS 5/16-111.5(d)(1).

A. Ameren Illinois Utilities: June 1, 2011 – May 31, 2016.

The IPA relied on Load Forecasts from Ameren as best estimates for future consumption factored for the largely unknown variable of retail switching. Since the Ameren 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. If during the planning process, the load projections for the Ameren portfolio require adjustments of greater than 200 MW (as indicated by the ICC DASR reports for the Ameren companies); a formal load readjustment will be requested and submitted by the Utility.

The ultimate goal of Ameren's Load Forecast provided by Ameren is not to identify the combined load of all customers of the Utility. Rather, the Ameren 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. Ameren utilizes a statistically adjusted end use model as the basis of its load forecasting process. After adjusting consumption data weather, seasonal variables, and economic conditions, a detailed core consumption model was developed.

As detailed in Attachment A, the Ameren load forecasting process begins with a multi-year analysis of historical loads. Recorded hourly loads are correlated to weather to generate a normalized full requirements load projection for each customer class. The normalized full requirements load projection for each customer class is then adjusted by losses, expected growth rates, retail competition switching trends, and results of statutory and other programs related to demand response and energy efficiency to yield a five-year projection of wholesale supply, capacity, and renewable energy resource requirements.

Comparisons between predicted and actual consumption volumes are highly correlated and are the best models available for forecasting loads for the eligible retail customers.

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. The IPA selected Ameren's Expected load model as the basis of the Draft Plan
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."*[14]

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 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 Draft Plan, the IPA assumes that Ameren intends to implement demand response programs sufficient to achieve their targeted peak reductions. Based on Ameren's analysis, the aggregated reduction in Ameren's maximum system load requirements for eligible retail customers due to demand response programs is projected as:

2011	**12 MW**	**2014**	**23 MW**
2012	**16 MW**	**2015**	**26 MW**
2013	**20 MW**		

The IPA will request validation of the ability to dispatch the Demand Response assets included in the

[14] 220 ILCS 5/8-103(c).

Ameren forecast in the near future. The IPA also notes that these Demand Resource values are effectively treated as pre-existing PRC credits within Capacity Resources projections for the Utility.

The IPA has also 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:

2011 106.8 GWh
2012 207.7 GWh
2013 298.2 GWh
2014 349.5 GWh
2015 365.6 GWh

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.

1. **Ameren Energy Supply Resources.** Ameren Illinois Utilities will secure the physical energy resources to meet the combine load requirements of eligible rate payers. For the purposes of this Draft 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 service
   - **QF** – Qualified Facilities. The Company must procure energy from any qualifying facility meeting the requirements of Rider QF – Qualifying Facilities. Such qualifying purchases are considered to be preexisting purchases and shall be recovered in Accrued Expenses for the Purchased Electricity Adjustment.[15]

   Table F presents Ameren's consolidated monthly volume schedule for each included rate class for the first three years covered by this five-year Plan. Tabular data for the entire sixty (60) months covered by this plan for Ameren can be found in Attachment B.

TABLE F: VOLUME PROJECTIONS PER RATE CLASS FOR AMEREN (JUNE 2011 THROUGH MAY 2014)

Contract Month	Projected Monthly Volume Requirements						
	DS1 MWH	DS2 MWH	DS3a MWH	DS5 MWH	QF MWH	Total Load MWH	Net Load MWH
June-11	1,009,692	279,200	57,565	27,766	-21,600	1,374,223	1,352,623
July-11	1,335,294	299,359	61,206	27,184	-22,320	1,723,043	1,700,723
August-11	1,333,094	296,921	60,391	27,998	-22,320	1,718,405	1,696,085
September-11	964,978	276,143	55,990	29,988	-21,600	1,327,100	1,305,500
October-11	798,363	267,637	53,874	31,788	-22,320	1,151,662	1,129,342
November-11	835,516	253,917	50,855	33,881	-21,600	1,174,169	1,152,569
December-11	1,107,141	268,221	53,156	36,520	-22,320	1,465,037	1,442,717
January-12	1,207,290	299,658	55,848	38,082	-22,320	1,600,877	1,578,557
February-12	1,042,234	265,476	49,918	34,903	-20,880	1,392,530	1,371,650
March-12	936,023	260,086	48,470	32,241	-22,320	1,276,820	1,254,500
April-12	747,656	231,751	43,955	32,097	-21,600	1,055,460	1,033,860

[15] Sheet 31.003 of the Rider PER tariff

May-12	776,769	248,105	47,731	28,990	-22,320	1,101,595	1,079,275
June-12	1,001,350	269,369	51,293	27,783	0	1,349,794	1,349,794
July-12	1,324,077	288,594	54,563	27,201	0	1,694,436	1,694,436
August-12	1,324,000	286,842	53,999	28,011	0	1,692,853	1,692,853
September-12	958,055	267,382	50,226	29,993	0	1,305,657	1,305,657
October-12	788,150	259,119	48,387	31,785	0	1,127,441	1,127,441
November-12	825,031	247,193	45,973	33,871	0	1,152,067	1,152,067
December-12	1,088,897	260,785	48,062	36,505	0	1,434,249	1,434,249
January-13	1,178,657	290,830	50,478	38,068	0	1,558,033	1,558,033
February-13	979,421	254,564	44,631	34,891	0	1,313,507	1,313,507
March-13	908,983	252,774	43,972	32,238	0	1,237,967	1,237,967
April-13	729,752	226,718	40,193	32,192	0	1,028,855	1,028,855
May-13	762,154	243,051	43,774	28,999	0	1,077,979	1,077,979
June-13	985,058	262,955	46,985	27,795	0	1,322,793	1,322,793
July-13	1,302,396	281,822	50,112	27,213	0	1,661,542	1,661,542
August-13	1,301,848	280,548	49,780	28,019	0	1,660,195	1,660,195
September-13	939,283	262,176	46,516	29,996	0	1,277,971	1,277,971
October-13	767,549	254,927	45,061	31,781	0	1,099,318	1,099,318
November-13	799,747	243,238	42,914	33,862	0	1,119,762	1,119,762
December-13	1,059,670	257,648	45,161	36,495	0	1,398,975	1,398,975
January-14	1,143,551	287,282	47,537	38,059	0	1,516,429	1,516,429
February-14	949,239	252,041	42,222	34,884	0	1,278,387	1,278,387
March-14	880,321	250,824	41,799	32,237	0	1,205,181	1,205,181
April-14	701,690	223,852	38,103	32,104	0	995,749	995,749
May-14	740,067	242,191	42,010	29,007	0	1,053,276	1,053,276

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 G below with the full 2011 to 2016 planning period presented in Attachment C.

TABLE G: AGGREGATED MONTHLY AND AVERAGE LOAD REQUIREMENTS FOR AMEREN (JUNE 2011 THROUGH MAY 2014)

Contract Month	Total Load (MWh)		Average Load (MW)	
	On-Peak	Off-Peak	On-Peak	Off-Peak
June-11	714,720	637,904	2,030	1,733
July-11	842,292	858,431	2,632	2,025
August-11	936,346	759,739	2,544	2,021
September-11	678,542	626,958	2,019	1,633
October-11	554,176	575,166	1,649	1,410
November-11	581,246	571,323	1,730	1,488
December-11	688,896	753,821	2,050	1,848
January-12	757,415	821,142	2,254	2,013
February-12	690,534	681,116	2,055	1,892
March-12	617,537	636,963	1,754	1,625
April-12	513,687	520,172	1,529	1,355
May-12	552,358	526,917	1,569	1,344
June-12	721,373	628,422	2,147	1,637
July-12	846,581	847,855	2,520	2,078
August-12	934,121	758,732	2,538	2,018
September-12	590,427	715,229	1,942	1,719
October-12	588,677	538,764	1,600	1,433

November-12	569,373	582,694	1,695	1,517
December-12	647,629	786,621	2,024	1,855
January-13	782,227	775,807	2,222	1,979
February-13	660,503	653,004	2,064	1,855
March-13	584,475	653,492	1,740	1,602
April-13	534,127	493,445	1,517	1,341
May-13	550,200	527,779	1,563	1,346
June-13	666,018	656,776	2,081	1,642
July-13	875,822	785,720	2,488	2,004
August-13	884,335	775,860	2,512	1,979
September-13	604,336	673,635	1,889	1,684
October-13	575,499	523,819	1,564	1,393
November-13	523,916	595,846	1,637	1,490
December-13	655,250	743,725	1,950	1,823
January-14	753,440	762,990	2,140	1,946
February-14	645,123	633,263	2,016	1,799
March-14	563,024	642,157	1,676	1,574
April-14	513,469	482,279	1,459	1,311
May-14	508,863	544,413	1,514	1,334

Energy and financial hedges required by the Eligible Retail Customers comes from five sources. First, the swap contract with Ameren Energy Marketing provides a financial hedge on 1000 MW of Around-the- Clock ("ATC") energy during the June 2011 – December 2012 period. Second, Ameren Illinois Utilities have some existing financial hedges in place for the period June 2011 through May 2012. Such hedges were executed as a result of the 2010 procurement process. Third, the Ameren Illinois Utilities will enter into fixed price physical supply contracts to hedge price exposure for the Residual Volumes (IPA will solicit standard wholesale products through a sealed-bid RFP per this Plan). Fourth, the Ameren Illinois Utilities will enter into agreements to purchase Energy Efficiency as Alternative Resource (EEAR) from existing Energy Efficiency Portfolio Standard (EEPS) programs offered to eligible retail customers in the Ameren service region. Fifth, the Ameren Utilities 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, the Utilities desire to pay a fixed price, and will settle all loads with the MISO at LMP. Under a swap transaction the Utilities 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 the Utilities to the MISO is offset by the LMP received from the supplier, leaving the Utilities 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 the Utilities 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 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 2011 and May 2014, 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 procurement plan. 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, utilities, 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 H and I. A full schedule of related planned procurement loads for Ameren can be found in Attachment D. Please note that consistent with past practice, the contract volumes in the schedule include a 10% increased purchase volume for the Peak periods in the months of July and August. This increase is included to serve as a hedge against unforeseen increases in weather-related demand during those periods.

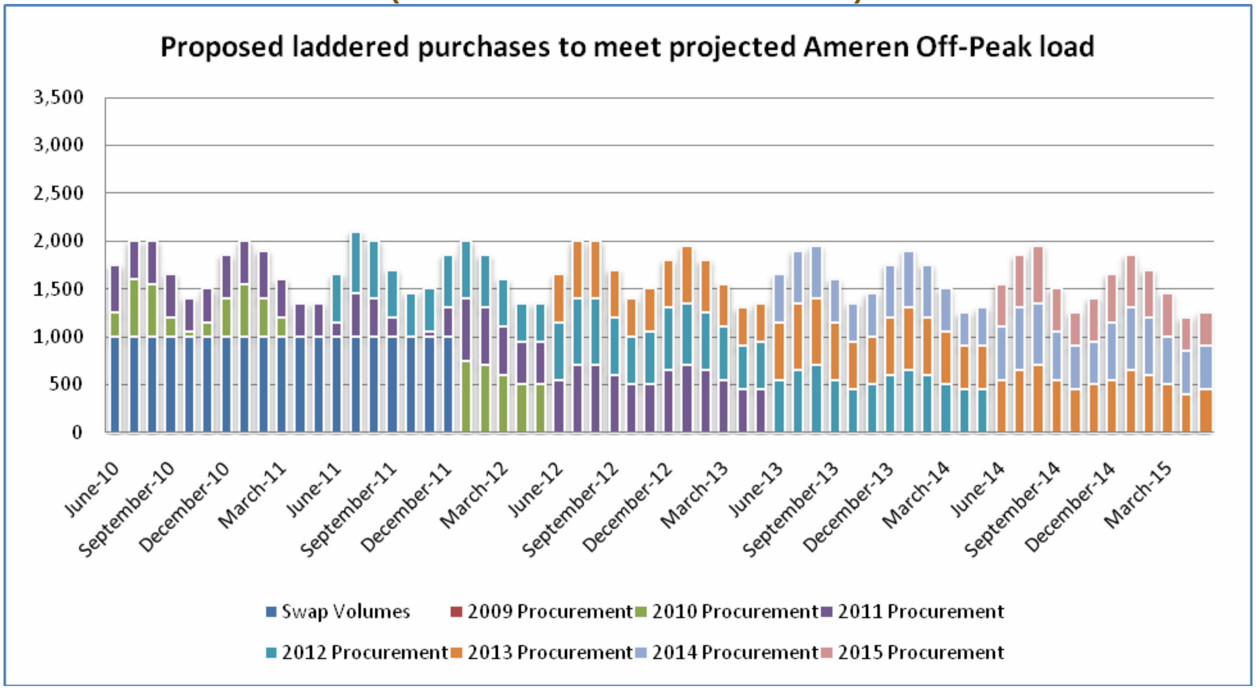
TABLE H: PROPOSED AMEREN OFF-PEAK LOAD VOLUMES TO BE SECURED IN 2011 PROCUREMENT

Contract Month	Off-Peak Contract Volumes to Secure (MW)						
	Projected Volume (MW)	Swap Volumes (MW)	2010 Procurement Volumes (MW)	Residual Volumes (MW)	2011 IPA Procurement (MW)	2012 IPA Procurement (MW)	2013 IPA Procurement (MW)
June-11	1,733	1,000	250	483	500	0	0
July-11	2,025	1,000	600	425	400	0	0
August-11	2,021	1,000	550	471	450	0	0
September-11	1,633	1,000	200	433	450	0	0
October-11	1,410	1,000	50	360	350	0	0
November-11	1,488	1,000	150	338	350	0	0
December-11	1,848	1,000	400	448	450	0	0
January-12	2,013	1,000	550	463	450	0	0
February-12	1,892	1,000	400	492	500	0	0
March-12	1,625	1,000	200	425	400	0	0
April-12	1,355	1,000	0	355	350	0	0
May-12	1,344	1,000	0	344	350	0	0
June-12	1,637	1,000	0	637	150	500	0
July-12	2,078	1,000	0	1,078	450	650	0
August-12	2,018	1,000	0	1,018	400	600	0
September-12	1,719	1,000	0	719	200	500	0
October-12	1,433	1,000	0	433	0	450	0
November-12	1,517	1,000	0	517	50	450	0
December-12	1,855	1,000	0	855	300	550	0
January-13	1,979	0	750	1,229	650	600	0
February-13	1,855	0	700	1,155	600	550	0
March-13	1,602	0	600	1,002	500	500	0
April-13	1,341	0	500	841	450	400	0
May-13	1,346	0	500	846	450	400	0
June-13	1,642	0	0	1,642	550	600	500
July-13	2,004	0	0	2,004	700	700	600
August-13	1,979	0	0	1,979	700	700	600
September-13	1,684	0	0	1,684	600	600	500
October-13	1,393	0	0	1,393	500	500	400
November-13	1,490	0	0	1,490	500	550	450
December-13	1,823	0	0	1,823	650	650	500
January-14	1,946	0	0	1,946	700	650	600
February-14	1,799	0	0	1,799	650	600	550
March-14	1,574	0	0	1,574	550	550	450
April-14	1,311	0	0	1,311	450	450	400
May-14	1,334	0	0	1,334	450	500	400

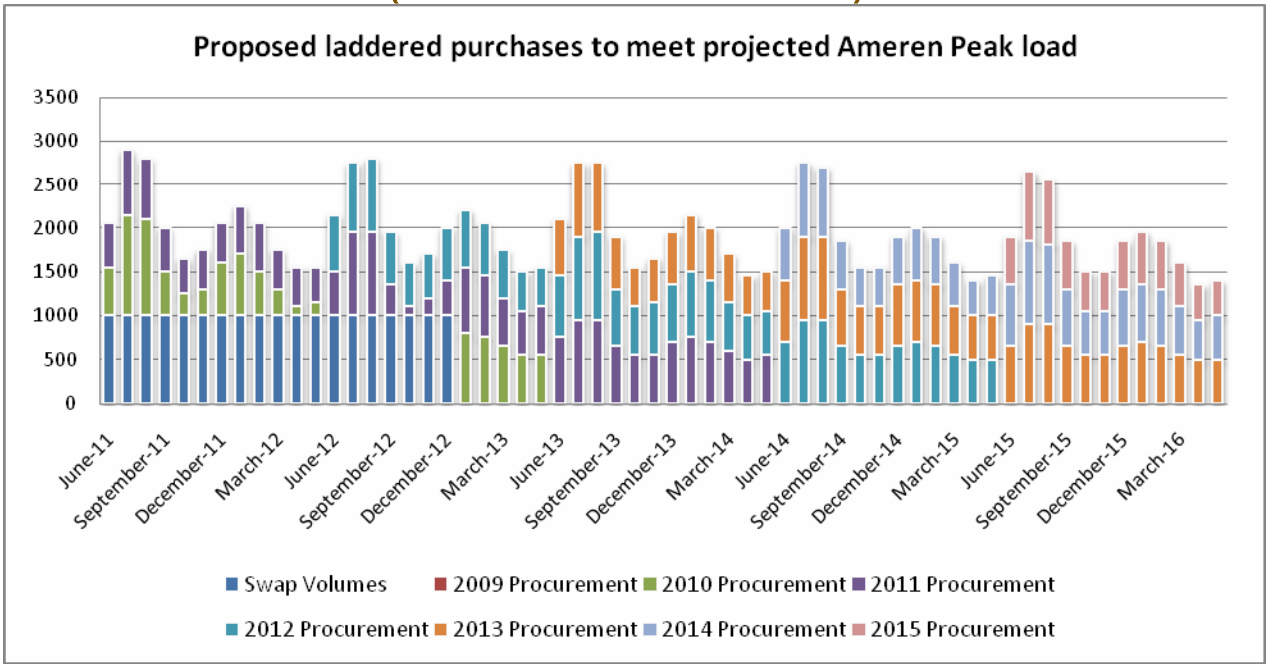
TABLE I: PROPOSED AMEREN ON-PEAK LOAD VOLUMES TO BE SECURED IN 2011 PROCUREMENT

Contract Month	Peak Contract Volumes to Secure (MW)						
	Projected Volume (MW)	Swap Volumes (MW)	2010 Procurement Volumes (MW)	Residual Volumes (MW)	2011 IPA Procurement (MW)	2012 IPA Procurement (MW)	2013 IPA Procurement (MW)
June-11	2030	1000	550	480	500	0	0
July-11	2895	1000	1150	745	750	0	0
August-11	2799	1000	1100	699	700	0	0
September-11	2019	1000	500	519	500	0	0
October-11	1649	1000	250	399	400	0	0
November-11	1730	1000	300	430	450	0	0
December-11	2050	1000	600	450	450	0	0
January-12	2254	1000	700	554	550	0	0
February-12	2055	1000	500	555	550	0	0
March-12	1754	1000	300	454	450	0	0
April-12	1529	1000	100	429	450	0	0
May-12	1569	1000	150	419	400	0	0
June-12	2147	1000	0	1147	500	650	0
July-12	2772	1000	0	1772	950	800	0
August-12	2792	1000	0	1792	950	850	0
September-12	1942	1000	0	942	350	600	0
October-12	1600	1000	0	600	100	500	0
November-12	1695	1000	0	695	200	500	0
December-12	2024	1000	0	1024	400	600	0
January-13	2222	0	800	1422	750	650	0
February-13	2064	0	750	1314	700	600	0
March-13	1740	0	650	1090	550	550	0
April-13	1517	0	550	967	500	450	0
May-13	1563	0	550	1013	550	450	0
June-13	2081	0	0	2081	750	700	650
July-13	2737	0	0	2737	950	950	850
August-13	2764	0	0	2764	950	1000	800
September-13	1889	0	0	1889	650	650	600
October-13	1564	0	0	1564	550	550	450
November-13	1637	0	0	1637	550	600	500
December-13	1950	0	0	1950	700	650	600
January-14	2140	0	0	2140	750	750	650
February-14	2016	0	0	2016	700	700	600
March-14	1676	0	0	1676	600	550	550
April-14	1459	0	0	1459	500	500	450
May-14	1514	0	0	1514	550	500	450

GRAPH 2: PROPOSED LADDERING SCHEDULE FOR AMEREN OFF-PEAK LOAD (JUNE 2011 THROUGH MAY 2016)



GRAPH 3: PROPOSED LADDERING SCHEDULE FOR AMEREN PEAK LOAD (JUNE 2011 THROUGH MAY 2016)



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.[16]

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 regulate derivatives (including financial swaps) and enforce position limits, margin requirements and reporting requirements. Such changes have the potential to increase costs for the AIUs, 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 the AIUs will be partially or completely exempt from the rule making outcome since the AIUs may be viewed as an end user and not a speculator. In summary and in light of the information currently available, the IPA recommends replacing financial swaps for the spring 2011 procurement event 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. The IPA will monitor the rule making process and recommend a course of action for procurement events beyond spring 2011 as the outcome of the current rule making process becomes clearer.

The IPA recommends consideration of the purchase of Energy Efficiency as Alternative Resource ("EEAR") for the Ameren 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 Ameren portfolio. In order to assure valid results in an EEAR procurement, the IPA recommends holding workshops during the fall of 2010 to establish the scope and nature of the EEAR event with the input of interested parties.

The IPA believes that the appropriate sources for EEAR bids would be programs that are evaluated in a manner equivalent to the existing Energy Efficiency Portfolio Standard ("EEPS") programs offered to eligible retail customers in the Ameren service region. The IPA notes that the results of the EEPS programs have been factored into the Ameren load forecasts in a manner similar to that of other pre-existing supply contracts for the past two cycles. Additionally, the EEPS programs are in their third year of operation and operate under an evaluation and oversight regime supervised by the ICC. These two factors lead the IPA to

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

determine that resources provided by the EEPS are reliable.

Similarly, energy efficiency resources that can show that they are evaluated in a manner equivalent to the EEPS programs, and are, consequently, equally reliable, are an appropriate source for EEAR bids. The IPA will also limit its procurement of Utility-administered resources to those resources that are not required to meet the Energy Efficiency Portfolio Standards.

The IPA proposes that EEAR assets should only be procured when the cost of the EEAR is less than the combined cost of the energy swaps, capacity, and renewable energy resource contracts held by Ameren for the contract period offered by the EEAR provider. As such, the EEAR contracts should be considered after the spring 2011 procurement events for energy resources, capacity, and renewable energy credits through a competitive solicitation.

Additional elements to the supply resources plan include:

Load Balancing Procedures. Upon Commission approval of this Plan, Ameren will be entering into financial swap transactions to hedge the energy price risk of the portfolio. 100% of the energy required to supply the load included in this Plan will be purchased in the MISO energy markets. 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.[17] In the event that Ameren's annual forecast increases above the High Forecast or decreases below the Low Forecast during the active delivery year of an approved Procurement Plan, Ameren shall promptly notify the IPA. The IPA will subsequently convene a meeting with Ameren, Commission, 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.

Over the term of this Plan, the most significant driver of load shifting levels is customer switching. If customer switching levels are significantly different from forecasted levels, a re-balancing of the portfolio may be warranted. Again, the IPA will work with Ameren, the Commission and procurement administrator to determine the appropriateness of rebalancing the portfolio.

Intercompany Dynamics Cost and Resource Sharing. As noted in section I, Ameren will procure power under this single Procurement Plan, for the combined needs of its Illinois utilities. To the extent permitted by the applicable legal and regulatory authorities, Ameren shall jointly pool such resources for their mutual benefit, and that of their eligible retail customers. They shall further allocate capacity and energy and cost responsibility therefore among themselves in proportion to their actual requirements. For purposes of determining such requirements, Ameren shall use either KWh or KW, as appropriate to determine the ratio of the individual Utility's requirement to the total requirement.

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

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.

Incremental Procurement Events. The IPA proposes that optional incremental procurements of up to an additional 10% of projected portfolio requirements in total be allowed under certain circumstances. First, the incremental procurements could seek to secure volumes for only those months that have not achieved a full 100% subscription level and only for years two and three of the plan. Second, the optional procurements would be triggered only when market indices demonstrate that prices for energy supply contracts for the targets months are at least 10% below the average weighted price of fixed price contracts already secured by the Utilities for those months. Third, such prices must be expected to be below the prices paid in the most recent procurement event. Fourth, the optional procurements would be limited to participation by bidders qualified in, and operate only under the agreed terms and conditions of the spring 2011 solicitation. Lastly, such procurement events would only occur, and the results accepted only with the authorization of the Commission.

2. **Ameren Capacity Resources.** 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 being discussed at MISO. In a September 2, 2010 presentation to the Supply Adequacy Working Group, the MISO laid out the enhancements that they are currently considering for Module E. These enhancements include moving to a 3-5 year forward looking construct and shifting to annual or seasonal compliance rather than the current monthly compliance. The presentation also includes a timeline which shows opportunities for stakeholder input, MISO finalizing their proposal in mid-October, tariff changes being filed at FERC on December 8, 2010, and an effective date for the changes of June 1, 2012. Given the uncertainty around this process, it may not be possible define the Capacity product required to comply with these future requirements until at least sometime after the December 8 filing and possibly not unit such time as FERC has issued its final order. With this in mind, the IPA will only procure the Capacity resources required to fully comply with the MISO resource adequacy requirements for the 2011 planning year which are currently known and certain and not attempt to procure resources for any future years in which the MISO requirement are uncertain at this time.

   For demonstration purposes, the tables included in this plan utilize the reserve margin of 4.5% that has been effective for the planning year beginning in June 2010 through May 2011. The planning reserve margin beginning June 2011 has yet to be established and therefore the IPA recommends that the Commission authorize the IPA's procurement administrator, in consultation with the IPA, the Commission Staff, the procurement monitor, and the Ameren Illinois Utilities, to adjust the quantities of capacity to acquire to comply with the applicable planning reserve requirements. Furthermore, to the extent to which it is impractical or impossible for the procurement administrator to modify its capacity RFP to fully account for all applicable capacity requirements the applicable planning reserve requirements, the IPA recommends that the Commission authorize the Ameren Illinois Utilities to make up the difference through one or more supplemental procurement processes. 100% of the monthly capacity requirements will be acquired for the first planning year (June 2011 through May 2012) as detailed in Table I:

TABLE I: PROPOSED AMEREN CAPACITY CONTRACT VOLUMES TO SECURE IN 2011 CYCLE (JUNE 2011 THROUGH MAY 2012)

Contract Month	Peak Load	Demand Response	Transmiss. Losses	Net Peak Load	Planning Reserves	Capacity Req.	2009 Purchase	2010 Purchase	2011 Purchase	% Hedged
June-11	3,901	0	80	3,901	179	4,160	1,370	1,570	1,220	100%
July-11	4,137	12	84	4,125	189	4,398	1,630	1,570	1,200	100%
August-11	4,144	12	84	4,132	190	4,406	1,650	1,480	1,280	100%
September-11	3,998	0	82	3,998	184	4,263	1,300	1,580	1,390	100%
October-11	2,802	0	57	2,802	129	2,988	960	910	1,120	100%
November-11	2,456	0	50	2,456	113	2,619	910	930	780	100%
December-11	3,016	0	62	3,016	138	3,216	1,100	1,340	780	100%
January-12	3,172	0	65	3,172	146	3,383	1,100	1,310	980	100%
February-12	2,868	0	59	2,868	132	3,058	1,020	1,150	890	100%
March-12	2,364	0	48	2,364	109	2,521	900	1,050	580	100%
April-12	2,148	0	44	2,148	99	2,290	800	840	650	100%
May-12	2,503	0	51	2,503	115	2,669	1,040	870	760	100%

Some capacity was procured in 2010 for the 2012 planning year. Pursuant to the previous discussion regarding MISO changing its capacity construct, the IPA will not make any additional purchases in 2011 for the 2012 planning year. This will result in a hedge of approximately 35% of the capacity requirement for the 2012 planning year (June 2012 through May 2013 as detailed in Table J:

TABLE J: PROPOSED AMEREN CAPACITY CONTRACT VOLUMES TO SECURE IN 2011 CYCLE (JUNE 2012 THROUGH MAY 2013)

Contract Month	Peak Load	Demand Response	Transmiss. Losses	Net Peak Load	Planning Reserves	Capacity Req.	2009 Purchase	2010 Purchase	% Hedged
June-12	3,826	0	78	3,904	176	4,080	0	1,440	35%
July-13	4,072	16	83	4,139	186	4,325	0	1,570	36%
August-14	4,095	16	83	4,162	187	4,349	0	1,530	35%
September-12	3,951	0	81	4,032	181	4,213	0	1,410	33%
October-13	2,565	0	52	2,617	118	2,735	0	920	34%
November-12	2,413	0	49	2,462	111	2,573	0	900	35%
December-12	2,965	0	61	3,025	136	3,162	0	1,200	38%
January-13	3,096	0	63	3,160	142	3,302	0	1,180	36%
February-13	2,795	0	57	2,852	128	2,980	0	1,080	36%
March-13	2,306	0	47	2,353	106	2,459	0	950	39%
April-13	2,099	0	43	2,141	96	2,238	0	810	36%
May-13	2,670	0	54	2,725	123	2,847	0	940	33%

No capacity will be procured for the third planning year (June 2013 through May 2014.

The IPA's procurement administrator will issue solicitations to lock-in fixed prices for fixed quantities of required capacity resources, using single-month, multi-month, and/or annual contracts during the period between June 2011 and May 2014, in whatever combinations are deemed appropriate by the procurement administrator, given the objectives described in this plan.

3. **Ameren Demand Response Resources.** Section 220 ILCS 5/16-111.5(b)(3)(ii).of the IPA Act requires the Plan to include:

the proposed mix of demand-response products for which contracts will be executed during the next year. The cost-effective demand-response measures shall be procured whenever the cost is lower than procuring comparable capacity products, provided that such products shall:

(A) Be 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 product to perform its obligations thereunder; and
(E) Meet the same credit requirements as apply to suppliers of capacity, in the applicable regional transmission market.[18]

The IPA recommends meeting the statutory obligation of procuring demand response as a free-standing obligation and not related to the replacement of Capacity Resources. The IPA proposes that the following characteristics be considered in securing these required demand response resources:

- **Product.** The IPA recommends procuring Demand Response assets that meet the statute's definitions and are registered as qualifying Planning Resource Credits ("PRC") by the Midwest Independent System Operator ("MISO"), but have not bid into MISO's Voluntary Capacity Auction.
- **Timing.** The IPA recommends that Demand Response assets be solicited as a separate procurement activity in the spring of 2011.
- **Volumes.** Consistent with statute, the IPA recommends that Demand Response Resources be procured to the extent that they meet the cost effectiveness and source requirements.
- **Term.** The IPA recommends that Demand Response Resources be secured for contract durations of between five and ten years.

4. **Ameren Renewable Energy Resources.** 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[19]

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,

[18] 220 ILCS 5/16-111.5(b)(3)(ii).
[19] 20 ILCS 3855/1-75(c)(1)

biodiesel, 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.[20]

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 are 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 K below cites the volume goals and cost limits.

TABLE K: RPS STANDARDS FOR AMEREN

Delivery period	Minimum Percentage (Annual volume goal)	Maximum Cost Standard
2011-2012	6% of June 1, 2009 through May 31, 2010 eligible retail customer load	The greater of an additional 0.5% of the amount paid per kilowatt hour by those customers during the year ending May 31, 2010 or 2.0% of the amount paid per kilowatt hour by those customers during the year ending May 31, 2007
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, 2012 through May 31, 2013 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, 2013 through May 31, 2014 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

Table L 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.

[20] 20 ILCS 3855/1-10.

TABLE L: 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

Per the statute, the higher of two separate calculations is used to establish each planning year's RBB. Tables M and N below presents the Annual Renewable Energy Resource Budgets resulting from the application of the statute's standards to the Ameren portfolio for planning years 2008-2009, 2009-2010, 2010-2011, and 2011-2012.

TABLE M: ANNUAL AMEREN RRB CALCULATIONS – OPTION A

Ameren RPS CALCULATIONS: Option A (Incremental increase on annual unit cost approach)				
(A) Planning Year	2008-2009	2009-2010	2010-2011	2011-2012
(B) Reference Year	2006-2007	2007-2008	2008-2009	2009-2010
(C) Reference Year Delivered Volume (MWh)	20,719,607	17,984,564	17,217,197	15,869,084
(D) Reference Year Delivered Cost	$1,801,867,729	$1,809,606,830	$1,853,574,838	$ 1,672,595,852
(E) Reference Year Unit Cost - [D / C]	$86.96	$100.62	$107.66	$105.40
(F) Planning Year Incremental RPS Cost Limit %	0.50%	0.50%	0.50%	0.50%
(G) Planning Year Incremental RPS Cost Limit Unit Price - [F * D]	$0.4348	$0.5031	$0.5383	$0.5270
(H) Planning Year Net RPS Cost Limit Unit Price	$0.4348	$0.9379	$1.4762	$2.0032
(I) Planning Year Projected Total Delivery Volume	20,719,607	17,700,274	16,525,235	15,065,960
(J) Planning Year Option A Cost Cap [I * H]	**$9,009,339**	**$16,601,474**	**$24,394,776**	**$30,180,309**

TABLE N: ANNUAL AMEREN RRB CALCULATIONS – OPTION B

Ameren RPS CALCULATIONS: Option B (Percentage Increase over Base Year unit cost approach)				
(A) Planning Year	2008-2009	2009-2010	2010-2011	2011-2012
(B) Reference Year	2006-2007			
(C) Reference Year Delivered Volume (MWh)	20,719,607			
(D) Reference Year Delivered Cost	$1,801,867,729			
(E) Reference Year Unit Cost ($/MWh) - [D / C]	$86.96			
(F) Planning Year Incremental RPS Cost Limit %	0.50%	1.00%	1.50%	2.00%
(G) Planning Year Net RPS Cost Limit Unit Price - [F * D]	$0.4348	$0.8696	$1.3045	$1.7393
(H) Planning Year Projected Total Delivery Volume	20,719,607	17,700,274	16,525,235	15,065,960
(I) Planning Year Option A Cost Cap [H * G]	**$9,009,339**	**$15,392,933**	**$21,556,602**	**$26,204,037**

Table O below displays the results of the RPS calculations for Planning Year-2011 for the Ameren Illinois Utilities.

TABLE O: AMEREN RPS TARGETS for 2011-2012

Ameren Renewable Portfolio Standard (RPS) Metrics (2011-2012)	
RPS Volume Target (MWh)	952,145
Renewable Energy Resource Budget (RRB)	$30,180,309
Average Price per Renewable Unit	$31.70
Estimated Customers Covered by RRB	1,169,723
Estimated Annual RPS Cost/Consumer	$25.80

Additional aspects of the proposed Renewable Energy Resources procurement are noted below:

- **Pricing Benchmark.** The Procurement Administrator is directed to continue to establish benchmark REC prices (as in 2009 and 2010 Procurement Plans), and to reject bids priced above the benchmarks. The benchmarks shall be set at levels that consider relevant market prices and the economic development benefits of in-state resources. 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.

- **Compliance Tracking.** The acquisition of RECs in amounts equal to the statutory requirement ensures compliance.

  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).

4. **Ameren Transmission Resources.** In addition to the acquisition of power and energy related products as detailed above, Ameren is obligated by the MISO Tariff to acquire certain transmission service related products and services to effectuate delivery of power and energy to the applicable loads. These services include Network Transmission Service and Ancillary Services. Further, Ameren may be allocated certain Financial Transmission/Auction Revenue Rights

   - **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 Utilities procure 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 2010 ARR allocation process at MISO, Ameren received a set of ARR entitlements and were awarded ARRs for the 2010 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.

B. Commonwealth Edison: June 1, 2011 – May 31, 2016.

The IPA relied on Load Forecasts from ComEd as best estimates for future consumption factored for the largely unknown variable of retail switching. Since ComEd's 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. If during the planning process, the load projections for the ComEd portfolio require adjustments of greater than 200 MW (as indicated by the ICC DASR reports for the Ameren companies); a formal load readjustment will be requested and submitted by the Utility.

The ultimate goal of the Load Forecast provided by ComEd is not to identify the combined load of all customers of the Utility. Rather, the ComEd 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. ComEd utilizes a statistically adjusted end use model as the basis of its load forecasting process. After adjusting consumption data weather, seasonal variables, and economic conditions, a detailed core consumption model was developed.

ComEd's 5-year hourly Load Forecast is based on the PUA's definition of Eligible Retail Customers. However, the ComEd customer classes deemed competitive by the PUA are different in maximum demand from those served by Ameren. Electricity supply to ComEd customers with demand greater than 100kW is competitive. Customers with demand greater than 100kW are no longer eligible for bundled service and are not included in the forecasts.

ComEd utilizes a forecasting process based on econometric models that 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.

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. The IPA selects the Expected Load Model as the basis of the procurement plan for the ComEd portfolio.

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."*[21]

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 Draft 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:

2011 42.0 MW
2012 53.1 MW
2013 63.6 MW
2014 74.2 MW
2015 85.0 MW

The IPA anticipates requesting validation of the ability to dispatch the Demand Response 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.[22] The annual aggregate reductions in ComEd's supply requirements to be acquired through the RFP process (net of customer switching) is projected to be:

2011 – 599.8 GWh
2012 – 931.1 GWh
2013 – 1,307.7 GWh
2014 – 1,683.9 GWh
2015 – 2,059.9 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

[21] 220 ILCS 5/8-103(c).
[22] 220 ILCS 5/8-103(b).

effectively treated as all other legacy supply contracts within the Supply Resources projections for the Utility.

1. **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 P 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 F.

TABLE P: VOLUME PROJECTIONS PER RATE CLASS FOR COMED (JUNE 2011 THROUGH MAY 2014)

Contract Month	Projected Monthly Volume Requirements									
	SF GWH	MF GWH	SFSH GWH	MFSH GWH	WH GWH	Small GWH	Condo GWH	DD GWH	GL GWH	Total GWH
June-11	2,132	442	49	102	44	600	20	15	1	3,405
July-11	2,842	585	50	112	49	662	27	15	1	4,342
August-11	2,615	551	45	102	49	662	30	16	1	4,072
September-11	1,829	395	34	76	43	584	26	16	1	3,005
October-11	1,568	340	41	82	41	552	23	18	1	2,665
November-11	1,712	358	72	131	40	541	22	18	1	2,894
December-11	2,062	408	111	212	44	603	31	19	1	3,491
January-12	2,042	396	126	258	45	618	37	19	1	3,542
February-12	1,718	355	114	235	42	573	34	17	1	3,089
March-12	1,640	344	98	201	42	579	31	17	1	2,955
April-12	1,418	302	70	139	39	524	25	15	1	2,534
May-12	1,545	334	53	106	41	558	23	16	1	2,677
June-12	2,132	443	48	100	44	568	20	15	1	3,372
July-12	2,876	593	50	111	49	631	27	16	1	4,355
August-12	2,629	555	45	101	49	629	30	17	1	4,056
September-12	1,808	391	33	74	43	550	26	17	1	2,942
October-12	1,577	343	41	81	41	531	23	19	1	2,655
November-12	1,706	357	70	128	40	514	22	19	1	2,858
December-12	2,052	407	108	208	44	572	31	20	1	3,443
January-13	2,057	398	125	256	45	593	38	20	1	3,534
February-13	1,659	342	108	224	40	528	33	17	1	2,953

March-13	1,631	341	97	197	42	550	31	17	1	2,908
April-13	1,418	302	69	137	39	502	26	16	1	2,509
May-13	1,540	333	52	104	41	531	24	16	1	2,643
June-13	2,131	443	48	99	44	567	20	16	1	3,368
July-13	2,913	600	50	111	49	634	27	16	1	4,402
August-13	2,633	556	44	100	49	626	30	17	1	4,056
September-13	1,812	392	33	73	43	552	26	17	1	2,949
October-13	1,565	340	40	79	41	532	23	19	1	2,640
November-13	1,690	353	69	125	40	512	22	19	1	2,833
December-13	2,063	408	107	206	44	575	31	20	1	3,456
January-14	2,059	399	123	253	45	593	38	20	1	3,531
February-14	1,658	342	106	220	40	528	33	17	1	2,946
March-14	1,629	341	95	194	42	550	31	18	1	2,902
April-14	1,413	301	68	135	39	502	26	16	1	2,501
May-14	1,533	332	51	102	41	529	24	16	1	2,629

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 Q below with the full 2011 to 2016 planning period presented in Attachment G.

TABLE Q: AGGREGATED MONTHLY AND AVERAGE LOAD REQUIREMENTS FOR COMED (JUNE 2011 THROUGH MAY 2014)

Contract Month	Total Load (MWh)		Average Load (MWh)	
	On-Peak	Off-Peak	On-Peak	Off-Peak
June-11	1,851,927	1,553,489	5,261	4,221
July-11	2,101,193	2,241,182	6,566	5,286
August-11	2,248,679	1,823,215	6,111	4,849
September-11	1,538,391	1,466,300	4,579	3,818
October-11	1,314,273	1,350,807	3,912	3,311
November-11	1,457,566	1,436,711	4,338	3,741
December-11	1,699,468	1,791,473	5,058	4,391
January-12	1,712,873	1,829,337	5,098	4,484
February-12	1,589,745	1,499,038	4,731	4,164
March-12	1,492,749	1,461,870	4,241	3,729
April-12	1,276,826	1,257,106	3,800	3,274
May-12	1,382,300	1,294,226	3,927	3,302
June-12	1,754,034	1,617,539	5,220	4,212
July-12	2,209,367	2,145,187	6,575	5,258
August-12	2,231,981	1,823,774	6,065	4,850
September-12	1,370,867	1,571,351	4,509	3,777
October-12	1,431,746	1,223,736	3,891	3,255
November-12	1,446,176	1,411,890	4,304	3,677
December-12	1,597,860	1,844,815	4,993	4,351
January-13	1,785,338	1,748,506	5,072	4,460
February-13	1,494,489	1,458,271	4,670	4,143
March-13	1,404,947	1,503,241	4,181	3,684
April-13	1,323,024	1,186,400	3,759	3,224

May-13	1,364,882	1,277,753	3,878	3,260
June-13	1,667,633	1,700,540	5,211	4,251
July-13	2,338,424	2,063,912	6,643	5,265
August-13	2,143,946	1,912,326	6,091	4,878
September-13	1,452,023	1,496,784	4,538	3,742
October-13	1,423,870	1,216,313	3,869	3,235
November-13	1,362,688	1,469,902	4,258	3,675
December-13	1,679,913	1,776,472	5,000	4,354
January-14	1,782,457	1,748,792	5,064	4,461
February-14	1,488,920	1,457,315	4,653	4,140
March-14	1,399,091	1,502,819	4,164	3,683
April-14	1,316,233	1,184,503	3,739	3,219
May-14	1,294,450	1,334,476	3,853	3,271

Energy required by the Eligible Retail Customers comes from five sources. First, the swap contract with ExGen provides a financial hedge on 3,000 MW of ATC energy during the June 2011 – May 2013 period. Second, certain fixed price physical supply contracts were secured through the 2010 procurement process. Third, IPA will solicit standard wholesale products through a sealed-bid RFP per this Plan. Fourth, balancing energy will be procured from the PJM-administered day-ahead and real-time energy markets. Lastly, ComEd will enter into agreements to purchase Energy Efficiency as Alternative Resource ("EEAR") from existing Energy Efficiency Portfolio Standard ("EEPS") programs offered to eligible retail customers in the ComEd service region.

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,[23] 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 2011 and May 2014, 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.

[23] 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.

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 Table R and S. A full schedule of related planned procurement loads for ComEd can be found in Attachment H. Please note that consistent with past practice, the contract volumes in the schedule include a 10% increased purchase volume for the Peak periods in the months of July and August. This increase is included to serve as a hedge against unforeseen increases in weather-related demand during those periods.

TABLE R: PROPOSED COMED PEAK LOAD VOLUMES TO SECURE IN 2011 PROCUREMENT CYCLE (JUNE 2011 THROUGH MAY 2014)

Contract Month	Peak Contract Volumes to Secure (MW)						
	Projected Volume (MW)	Swap Volumes (MW)	2010 Procurement Volumes (MW)	Residual Volumes (MW)	2011 IPA Procurement (MW)	2012 IPA Procurement (MW)	2013 IPA Procurement (MW)
June-11	5261	3000	650	1611	1600	0	0
July-11	7223	3000	2000	2223	2200	0	0
August-11	6722	3000	1650	2072	2050	0	0
September-11	4579	3000	150	1429	1450	0	0
October-11	3912	3000	0	912	900	0	0
November-11	4338	3000	0	1338	1350	0	0
December-11	5058	3000	500	1558	1550	0	0
January-12	5098	3000	550	1548	1550	0	0
February-12	4731	3000	300	1431	1450	0	0
March-12	4241	3000	0	1241	1250	0	0
April-12	3800	3000	0	800	800	0	0
May-12	3927	3000	0	927	950	0	0
June-12	5220	3000	0	2220	650	1550	0
July-12	7233	3000	0	4233	2050	2200	0
August-12	6672	3000	0	3672	1650	2000	0
September-12	4509	3000	0	1509	150	1350	0
October-12	3891	3000	0	891	0	900	0
November-12	4304	3000	0	1304	0	1300	0
December-12	4993	3000	0	1993	500	1500	0
January-13	5072	3000	0	2072	550	1500	0
February-13	4670	3000	0	1670	250	1400	0
March-13	4181	3000	0	1181	0	1200	0
April-13	3759	3000	0	759	0	750	0
May-13	3878	3000	0	878	0	900	0
June-13	5211	0	0	5211	1800	1850	1550
July-13	7308	0	0	7308	2550	2550	2200
August-13	6700	0	0	6700	2350	2350	2000
September-13	4538	0	0	4538	1600	1600	1350
October-13	3869	0	0	3869	1350	1350	1150
November-13	4258	0	0	4258	1500	1500	1250

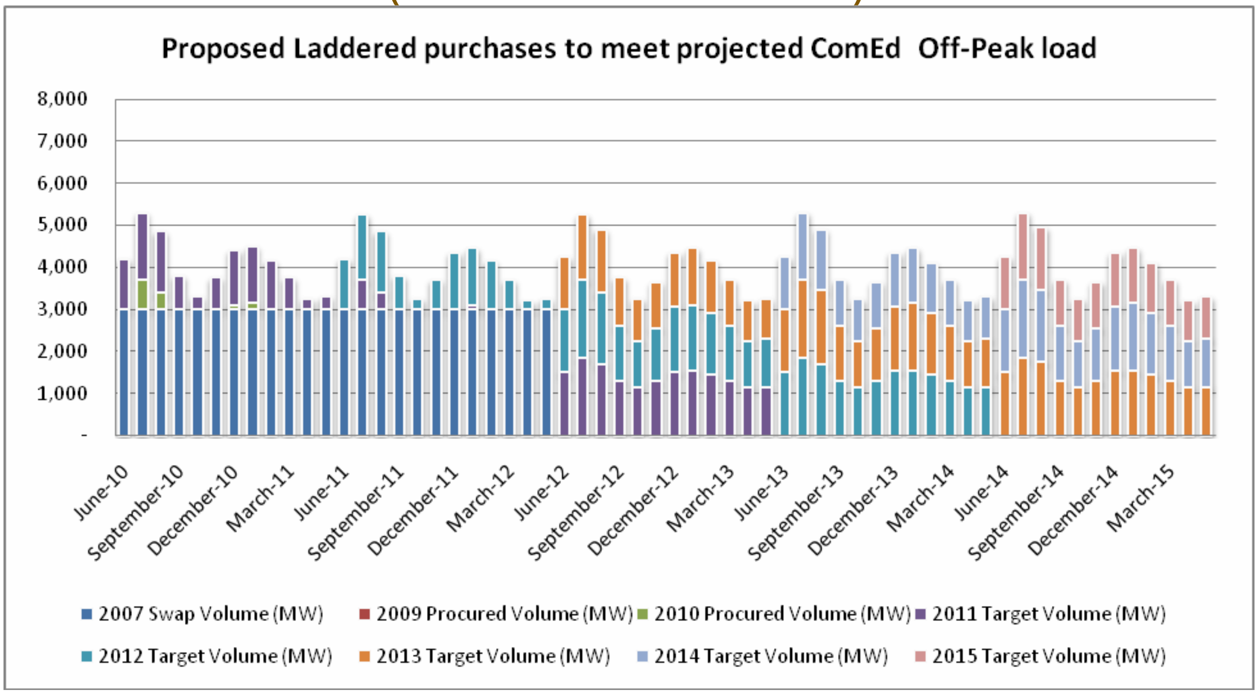
December-13	5000	0	0	5000	1750	1750	1500
January-14	5064	0	0	5064	1750	1800	1500
February-14	4653	0	0	4653	1650	1600	1400
March-14	4164	0	0	4164	1450	1450	1250
April-14	3739	0	0	3739	1300	1300	1150
May-14	3853	0	0	3853	1350	1350	1150

TABLE S: PROPOSED COMED OFF-PEAK LOAD VOLUMES TO SECURE IN 2011 PROCUREMENT CYCLE (JUNE 2011 THROUGH MAY 2014)

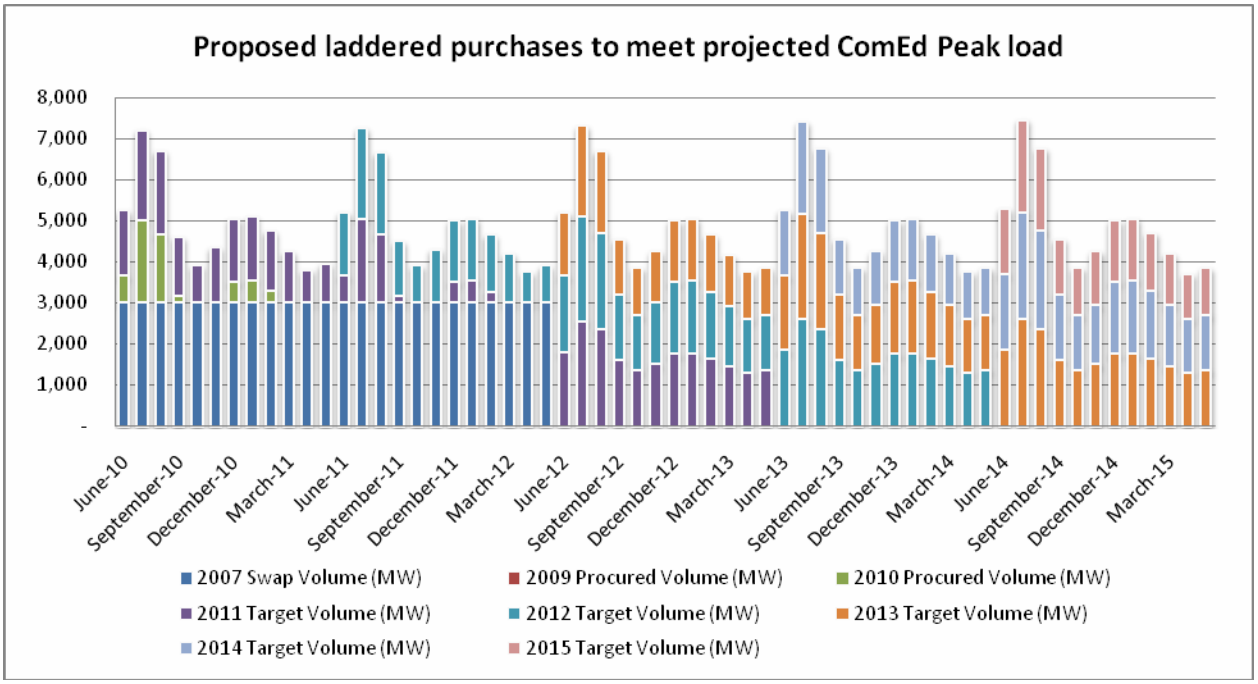
Contract Month	Off-Peak Contract Volumes to Secure (MW)						
	Projected Volume (MW)	Swap Volumes (MW)	2010 Procurement Volumes (MW)	Residual Volumes (MW)	2011 IPA Procurement (MW)	2012 IPA Procurement (MW)	2013 IPA Procurement (MW)
June-11	4,221	3,000	0	1,221	1200	0	0
July-11	5,286	3,000	700	1,586	1600	0	0
August-11	4,849	3,000	400	1,449	1450	0	0
September-11	3,818	3,000	0	818	800	0	0
October-11	3,311	3,000	0	311	300	0	0
November-11	3,741	3,000	0	741	750	0	0
December-11	4,391	3,000	100	1,291	1300	0	0
January-12	4,484	3,000	150	1,334	1350	0	0
February-12	4,164	3,000	0	1,164	1150	0	0
March-12	3,729	3,000	0	729	750	0	0
April-12	3,274	3,000	0	274	250	0	0
May-12	3,302	3,000	0	302	300	0	0
June-12	4,212	3,000	0	1,212	0	1200	0
July-12	5,258	3,000	0	2,258	700	1550	0
August-12	4,850	3,000	0	1,850	400	1450	0
September-12	3,777	3,000	0	777	0	800	0
October-12	3,255	3,000	0	255	0	250	0
November-12	3,677	3,000	0	677	0	700	0
December-12	4,351	3,000	0	1,351	50	1300	0
January-13	4,460	3,000	0	1,460	100	1350	0
February-13	4,143	3,000	0	1,143	0	1150	0
March-13	3,684	3,000	0	684	0	700	0
April-13	3,224	3,000	0	224	0	200	0
May-13	3,260	3,000	0	260	0	250	0
June-13	4,251	0	0	4,251	1500	1500	1250
July-13	5,265	0	0	5,265	1850	1850	1550
August-13	4,878	0	0	4,878	1700	1700	1500
September-13	3,742	0	0	3,742	1300	1300	1150
October-13	3,235	0	0	3,235	1150	1100	1000
November-13	3,675	0	0	3,675	1300	1250	1100
December-13	4,354	0	0	4,354	1500	1550	1300
January-14	4,461	0	0	4,461	1550	1550	1350
February-14	4,140	0	0	4,140	1450	1450	1250
March-14	3,683	0	0	3,683	1300	1300	1100
April-14	3,219	0	0	3,219	1150	1100	950
May-14	3,271	0	0	3,271	1150	1150	950

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. By dollar-cost averaging in this manner, the IPA mitigates risk to ComEd's Eligible Retail Customers.

GRAPH 4: PROPOSED LADDERING SCHEDULE FOR COMED OFF-PEAK LOAD (JUNE 2011 THROUGH MAY 2016)



GRAPH 5: PROPOSED LADDERING SCHEDULE FOR COMED PEAK LOAD (JUNE 2011 THROUGH MAY 2016)



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.[24]

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:

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[24] 220 ILCS 5/16 – 111.5(c)(1)(v); 220 ILCS 5/16-111.5(e)(2).

- 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 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.

The IPA recommends consideration of the purchase of Energy Efficiency as Alternative Resource ("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.

The IPA believes that the appropriate sources for EEAR bids would be programs that are evaluated in a manner equivalent to the existing Energy Efficiency Portfolio Standard ("EEPS") programs offered to eligible retail customers in the ComEd service region. The IPA notes that the results of the EEPS programs have been factored into the ComEd load forecasts in a manner similar to that of other pre-existing supply contracts for the past two cycles. Additionally, the EEPS programs are in their third year of operation and operate under an evaluation and oversight regime supervised by the ICC. These two factors lead the IPA to determine that resources provided by the EEPS are reliable.

Similarly, energy efficiency resources that can show that they are evaluated in a manner equivalent to the EEPS programs, and are, consequently, equally reliable, are an appropriate source for EEAR bids. The IPA will also limit its procurement of Utility-administered resources to those resources that are not required to meet the Energy Efficiency Portfolio Standards.

The IPA proposes that EEAR assets should only be procured when the cost of the EEAR is less than the combined cost of the energy swaps, capacity, and renewable energy resource contracts held by ComEd for the contract period offered by the EEAR provider. As such, the EEAR contracts should be considered after the spring 2011 procurement events. Contracts would be secured through direct negotiation between the IPA and ComEd subject to oversight and authorization by the ICC. If EEAR assets are not cost competitive, then no contracts shall be executed. In order to assure valid results in an EEAR procurement, the IPA recommends holding workshops during the fall of 2010 to establish the scope and nature of the EEAR event with the input of interested parties.

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. In the event that ComEd's annual forecast increases above the High Forecast or decreases below the Low Forecast during the active delivery year of an approved Procurement Plan, ComEd shall promptly notify the IPA. The IPA will subsequently convene a meeting with ComEd, the Commission, 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.

Over the term of this Plan, the most significant driver of load shifting levels is customer switching. If customer switching levels are significantly different from forecasted levels, a re-balancing of the portfolio may be warranted. Again, the IPA will work with ComEd, the Commission and procurement administrator to determine the appropriateness of rebalancing the portfolio.

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.

Incremental Procurement Events. The IPA proposes that optional incremental procurements of up to an additional 10% of projected portfolio requirements be allowed under certain circumstances. First, the incremental procurements could seek to secure volumes for only those months that have not achieved a full 100% subscription level. Second, the optional procurements would be triggered only when market indices demonstrate that prices for energy supply contracts for the targets months are below the average weighted price of fixed price contracts already secured by the Utilities for those months. Third, the optional procurements would be limited to participation by bidders qualified in and operate only under the terms and conditions agreed to in the spring 2011 solicitation. Lastly, such procurement events would only occur, and the results accepted only with the authorization of the Commission.

2. **ComEd Capacity Resources.** 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 2011 - May 2014 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.

The IPA's procurement administrator will issue solicitations to lock-in fixed prices for fixed quantities of required capacity resources, using single-month, multi-month, and/or annual contracts during the period between June 2011 and May 2014, in whatever combinations are deemed appropriate by the procurement administrator, given the objectives described in this plan.

3. **ComEd Demand Response Resources.** Section 220 ILCS 5/16-111.5(b)(3)(ii).of the IPA Act requires the Plan to include:

> *the proposed mix of demand-response products for which contracts will be executed during the next year. The cost-effective demand-response measures shall be procured whenever the cost is lower than procuring comparable capacity products, provided that such products shall:*
>
> *(F) Be procured by a demand-response provider from eligible retail customers*
> *(G) 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*
> *(H) Provide for customers' participation in the stream of benefits produced by the demand-response products;*
> *(I) 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 product to perform its obligations thereunder; and*
> *(J) Meet the same credit requirements as apply to suppliers of capacity, in the applicable regional transmission market.*[25]

The IPA recommends meeting the statutory obligation of procuring demand response as a free-standing obligation and not related to the replacement of Capacity Resources. The IPA proposes that the following characteristics be considered in securing these required demand response resources:

- **Product.** The IPA recommends procuring Demand Response assets that meet the statute's definitions and are registered as qualifying capacity resources in the PJM RPM Auction.
- **Timing.** The IPA recommends that Demand Response assets be solicited as a separate procurement activity in the spring of 2011.
- **Volumes.** Consistent with statute, the IPA recommends that Demand Response Resources be procured to the extent that they meet the cost effectiveness and source requirements.
- **Term.** The IPA recommends that Demand Response Resources be secured for contract

[25] 220 ILCS 5/16-111.5(b)(3)(ii).

durations of between five and ten years.

4. ComEd Renewable Energy Resources. 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*[26]

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, 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.*[27]

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. As the above-quoted definition makes clear, only landfill gas produced in Illinois qualifies as a renewable energy resource for purposes of this procurement of RECs.

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 T below cites the volume goals and cost limits.

TABLE T: RPS STANDARDS FOR COMED

Delivery period	Minimum Percentage (Annual volume goal)	Maximum Cost Standard
2011-2012	6% of June 1, 2009 through May 31, 2010 eligible retail customer load	The greater of an additional 0.5% of the amount paid per kilowatt hour by those customers during the year ending May 31, 2010 or 2.0% of the amount paid per kilowatt hour by those customers during the year ending May 31, 2007
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, 2012 through May 31, 2013 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

[26] 20 ILCS 3855/1-75(c)(1)
[27] 20 ILCS 3855/1-10.

2015-2016	10% of June 1, 2013 through May 31, 2014 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

Table U below presents the Annual Volume Targets resulting from the application of the statute's standards to the ComEd portfolio for planning years 2008-2009, 2009-2010, and 2010-2011.

TABLE U: 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

Per the statute, the higher of two separate calculations is used to establish each planning year's RBB. Tables V and W below presents the Annual Renewable Energy Resource Budgets resulting from the application of the statute's standards to the ComEd portfolio for planning years 2008-2009, 2009-2010, 2010-2011, and 2011-2012.

TABLE V: ANNUAL COMED RRB CALCULATIONS – OPTION A

ComEd RPS CALCULATIONS: Option A (Incremental increase on annual unit cost approach)				
(A) Planning Year	2008-2009	2009-2010	2010-2011	2011-2012
(B) Reference Year	2006-2007	2007-2008	2008-2009	2009-2010
(C) Reference Year Delivered Volume (MWh)	39,802,463	39,109,145	37,740,282	35,284,241
(D) Reference Year Delivered Cost	$3,736,750,000	$4,205,233,624	$4,462,038,949	$3,952,018,105
(E) Reference Year Unit Cost - [D / C]	$93.88	$107.53	$118.23	$112.01
(F) Planning Year Incremental RPS Cost Limit %	0.50%	0.50%	0.50%	0.50%
(G) Planning Year Incremental RPS Cost Limit Unit Price - [F * D]	$0.4694	$0.5376	$0.5912	$0.5600
(H) Planning Year Net RPS Cost Limit Unit Price	$0.4694	$1.0070	$1.5982	$2.1582
(I) Planning Year Projected Total Delivery Volume	39,837,081	39,422,473	36,095,906	35,759,281
(J) Planning Year Option A Cost Cap [I * H]	**$18,700,000**	**$39,700,000**	**$57,688,135**	**$77,176,270**

TABLE W: ANNUAL COMED RRB CALCULATIONS – OPTION B

ComEd RPS CALCULATIONS: Option B (Percentage Increase over Base Year unit cost approach)				
(A) Planning Year	2008-2009	2009-2010	2010-2011	2011-2012
(B) Reference Year	**2006-2007**			
(C) Reference Year Delivered Volume (MWh)	**39,802,463**			
(D) Reference Year Delivered Cost	**$3,736,750,000**			
(E) Reference Year Unit Cost ($/MWh) - [D / C]	**$93.88**			
(F) Planning Year Incremental RPS Cost Limit %	0.50%	1.00%	1.50%	2.00%
(G) Planning Year Net RPS Cost Limit Unit Price - [F * D]	$0.4694	$0.9388	$1.4082	$1.8776
(H) Planning Year Projected Total Delivery Volume	39,837,081	39,422,473	36,095,906	35,759,281
(I) Planning Year Option A Cost Cap [H * G]	**$18,700,000**	**$37,010,756**	**$50,831,544**	**$67,143,329**

Table X below displays the results of the RPS calculations for Planning Year 2010-2011 for ComEd.

TABLE X: COMED RPS TARGETS for 2011-2012

ComEd Renewable Portfolio Standard (RPS) Metrics (2011-2012)	
RPS Volume Target (MWh)	2,117,054
Renewable Energy Resource Budget (RRB)	$77,176,270
Average Price per Renewable Unit	$36.45
Estimated Customers Covered by RRB	3,742,263
Estimated Annual RPS Cost/Consumer	$20.62

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

Additional aspects of the proposed Renewable Energy Resources procurement are noted below:

- **Pricing Benchmark.** The Procurement Administrator is directed to continue to establish benchmark REC prices (as in the 2009 and 2010 Plans), and to reject bids priced above the benchmarks. The benchmarks shall be set at levels that consider relevant market prices and the economic development benefits of in-state resources. 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 beginning June 1, 2011 cost effective renewable energy resources be procured first from facilities in the State of Illinois or from facilities located in states adjacent to Illinois, and then from facilities located elsewhere.

- **Compliance Tracking.** The acquisition of RECs in amounts equal to the statutory requirement ensures compliance.

  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 ComEd to comply with the statutory requirements shall be retired in compliance with 1-75 (c) (4).

4. **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.

ATTACHMENT A: Ameren Illinois Utilities Load Forecast for Five Year Planning Period, June 2011 through May 2016

Ameren Illinois Utilities
Load Forecast for the period June 1, 2011 – May 31, 2016

Purpose and Summary

The development of the load forecast is an essential step in the development of the Utilities' 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, 2011 – May 31, 2016 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 exponential smoothing models. Models were developed using revenue month sales data spanning from January 1995 (data for some models start later than 1995) to September/October 2007. 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[1]

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:

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

[1] Commercial indices for AmerenIP are constructed using similar approaches; however, non-manufacturing employment and GDP were used instead of households and personal income variables in estimating the indices.

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.

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

$\mathrm{Energy}_{05}^{\mathrm{Type}}$ is the unit energy consumption of each end-use in 2005 according to EIA data adjusted for each service territory. $\mathrm{HeatShare}_{05}^{\mathrm{Type}}$ 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.

$$\mathrm{HeatShare}_{05}^{\mathrm{Type}} = \mathrm{Saturation}_{05}^{\mathrm{Type}} \text{ x Structural Index}_{05} \qquad (6)$$

where

$$\text{Structural Index}_y = (\text{Building Shell Efficiency}_y \text{ x Surface Area}_y) / (\text{Building Shell Efficiency}_{05} \text{ x Surface Area}_{05}) \qquad (7)$$

where

$$\text{Surface Area} = 892 + 1.44 \text{ x House Size} \qquad (8)$$

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:

$$HeatUse_{y,m} = \left(\frac{BDays_{y,m}}{AvgBDays}\right) x \left(\frac{WgtHDD_{y,m}}{HDD_{05}}\right) x \left(\frac{Income_{y,m}}{Income_{05}}\right)^{0.20} x \left(\frac{HHSize_{y,m}}{HHSize_{05}}\right)^{0.25} x \left(\frac{Elec\mathrm{Price}_{y,m}}{Elec\mathrm{Price}_{05,7}}\right) x \left(\frac{Gas\mathrm{Price}_{y,m}}{Gas\mathrm{Price}_{05,7}}\right) \qquad (9)$$

where $\mathrm{Price}_{y,m}$ 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, $\mathrm{HHIncome}_{y,m}$ is the average real income per household in a year (y) and month (m), $\mathrm{HHIncome}_{05}$ is the average real income per household in 2005, $\mathrm{HHSize}_{y,m}$ is the average household size in a year (y) and month (m), HHSize_{05} is the average household size in 2005, $\mathrm{HDD}_{y,m}$ 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:

$$\mathrm{XOther}_{y,m} = \mathrm{OtherIndex}_{y} \times \mathrm{OtherUse}_{y,m} \qquad (10)$$

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 peak forecast for the Utilities' eligible customer retail load was performed at the operating company level. For each company (AmerenIP, AmerenCIPS, and AmerenCILCO), historical hourly data was collected. The data for each company was gathered for the longest period of time available that was consistent with the current load. This ranged by company from about 5 to 6 years. From this hourly data, daily peak loads were determined. The daily peak loads were the basis for the peak load model. The loads were at transmission level and excluded wholesale load.

The 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, and energy growth trend variables. 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).

Lagged weather variables are also employed in the model. Multiple days of lags of each temperature spline are included, as well as a Rolling HDD and CDD variable. This captures the build-up effect observed in peak load. When there are multiple very hot days in a row, buildings tend to hold more heat and require more air conditioning, which in turn results in higher loads.
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.

Finally, each model contains some variables to capture load growth. Where available, weather normalized 12-month rolling average sales were used to capture growth. This modeling technique is based on the assumption that increased energy usage drives the peak load. In essence it assumes that load factor is relatively stable over time. The sales are weather normalized and averaged over 12 months because actual weather and seasonal variation are already accounted for within the model by other independent variables. This specification allows for peak load growth to be driven by true load additions that are experienced because of customer growth or usage per customer increases that are not influenced by weather. Again the actual weather impacts are already accounted for through the weather variables described above.

In the absence of sufficient history of weather normalized sales, a trend variable is used that, in essence, attributes peak load growth to the passage of time. Under positive economic conditions with normal load growth, this is a reasonable approach to capture the normal increases that are known to take place in the peak load.

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, ranges from 85.6% to 89.7%. The Mean Absolute Percent Error (MAPE) of the models range from 3.94% to 4.54%, indicating that over all of the years of the analysis, the average day has an absolute error within this range.

Forecasting Normal Weather Conditions for the Daily Peak Model

The AmerenIL utilities define normal for a weather element as the arithmetic mean of that weather element computed over the 10 year period from 2000-2009. 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 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 forecast model to produce a normal peak load forecast.

Final Forecast Steps

The MetrixLT software develops the hourly load by delivery service class by combining the monthly sales forecast by class, hourly load shapes by class from load research, and distribution loss factors. The software calibrates the delivery service classes to the total system peak forecast developed with the daily peak model. The hourly forecast for each company is combined to develop the Ameren Illinois hourly load forecast.

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. The Utilities 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, the Utilities have 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 2010). The Utilities then reviewed these trends and using their qualitative judgment made adjustments such that the end result is a forecast characterized by increasing switching, although at a slowing rate over time. 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 the Utilities' combined power supply requirements for eligible retail customers.

Residential

As of June 1, 2010, there were five Alternative Retail Electric Suppliers (ARES) registered with both the ICC and the Utilities to serve residential customers in the Utilities' territories, as compared to fifteen so registered to serve non-residential customers in the Utilities territories. However, as of the date this plan was prepared, less than 0.1% of residential customers of the Utilities have exercised their right to choose an ARES (switching is approximately 1.2% when RTP is considered) and significant switching is not expected in the near term.

Past retail switching has likely been dampened in part by the rate credits resulting from Public Act 095-481. These credits provide payment to residential customers over several years and are affected if the customer leaves utility service. After these credits expire (starting in 2010), it is reasonable to expect some increase in residential switching and such assumptions have been imbedded in the forecast.

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 four to five in the last twelve months. More so, significant reductions in market prices or changes in the regulations regarding switching rules (i.e. “wet” signature requirements) 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 Utilities by CNT Energy. Since program inception in 2007, participation in the program has been steadily increasing and now exceeds 1.0% of available customers.

The Utilities estimate that the combination of residential switching to ARES and real time pricing will be slightly greater than 10% by the end of the five year planning period.

0-149 kW Non-Residential

This customer class has seen approximately 40% switching since January 1, 2007 which represents about a 18% 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 Utilities tariff, 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.

The Utilities estimate that switching in this class will be approximately 54% by the end of the five year planning period.

150-399 kW Non-Residential

This customer class has seen approximately 69% switching since January 1, 2007 which represents about a 14% 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 Utilities tariff, 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 classes, it is reasonable to assume ARES will focus efforts on the smaller customer classes. Finally, customers in this class will also have the option for real time pricing, giving them other alternatives to switch away from tariff.

The Utilities estimate that switching in this class will be approximately 83% 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 service under an ARES or the Utilities real time pricing tariff. Therefore, this customer class assumes 100% switching and is therefore no longer considered part of the Utilities fixed price load.

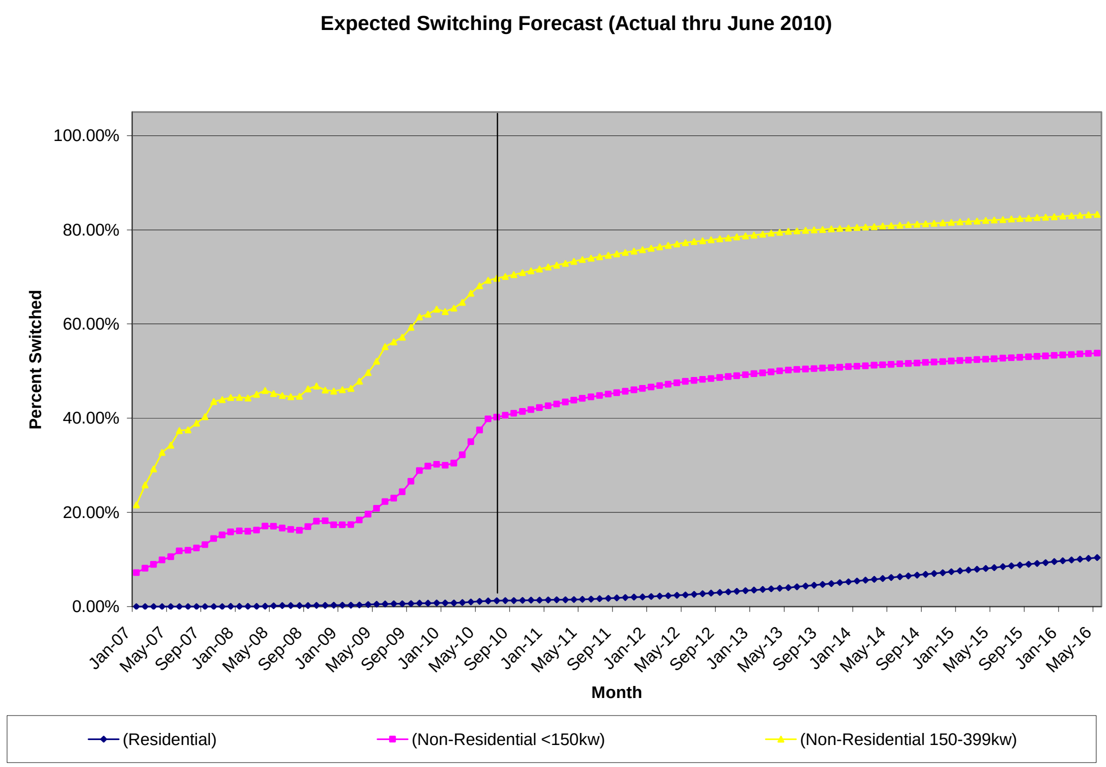
1,000 kW and Greater Non-Residential

This customer class is declared competitive and therefore these customers can no longer take the fixed price service 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, market prices change or switching rules are modified. However, switching will likely at some point approach saturation (the point at which all of those customers willing to switch and acceptable to ARES have done so), thus eventually resulting in a slow down of customer switching rates.

The current assumption within the Plan is that switching will continue, although a decreasing rate over time. Expected values through May 31, 2016 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 customer class, the Utilities currently project a 5-year Compound Annual Growth rate of -0.6%. Commercial growth rates for the Utilities are projected to be 2.4%.

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. The effective reduction in the Utilities' aggregate supply requirements to be acquired through the RFP process (net of customer switching) is projected to be:

2011	12 MW
2012	16 MW
2013	20 MW
2014	23 MW
2015	26 MW

The Utilities shall review the cost effectiveness of these programs as specified by statute and shall modify the program design accordingly if needed.

Energy Efficiency Programs

Section 12-103 (b) of Public Act 095-0481 establishes specific requirements for Energy Efficiency Programs that reduce energy consumption of delivery services customers. The effective reduction in the Utilities' supply requirements to be acquired through the RFP process (net of customer switching) is projected to be

2011	106,792 MWh
2012	207,719 MWh
2013	298,197 MWh
2014	386,608 MWh
2015	447,066 MWh

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

ATTACHMENT B: Ameren Illinois Utilities Monthly Volume Projections per Rate Class for Five Year Planning Period, June 2011 through May 2016

Ameren Illinois Utilities Monthly Volume Projections per Rate Class for Five Year Planning Period, June 2011 through May 2016

Contract Month	Projected Monthly Volume Requirements						
	DS1 MWH	DS2 MWH	DS3a MWH	DS5 MWH	QF MWH	Total Load MWH	Net Load MWH
June-11	1,009,692	279,200	57,565	27,766	-21,600	1,374,223	1,352,623
July-11	1,335,294	299,359	61,206	27,184	-22,320	1,723,043	1,700,723
August-11	1,333,094	296,921	60,391	27,998	-22,320	1,718,405	1,696,085
September-11	964,978	276,143	55,990	29,988	-21,600	1,327,100	1,305,500
October-11	798,363	267,637	53,874	31,788	-22,320	1,151,662	1,129,342
November-11	835,516	253,917	50,855	33,881	-21,600	1,174,169	1,152,569
December-11	1,107,141	268,221	53,156	36,520	-22,320	1,465,037	1,442,717
January-12	1,207,290	299,658	55,848	38,082	-22,320	1,600,877	1,578,557
February-12	1,042,234	265,476	49,918	34,903	-20,880	1,392,530	1,371,650
March-12	936,023	260,086	48,470	32,241	-22,320	1,276,820	1,254,500
April-12	747,656	231,751	43,955	32,097	-21,600	1,055,460	1,033,860
May-12	776,769	248,105	47,731	28,990	-22,320	1,101,595	1,079,275
June-12	1,001,350	269,369	51,293	27,783	0	1,349,794	1,349,794
July-12	1,324,077	288,594	54,563	27,201	0	1,694,436	1,694,436
August-12	1,324,000	286,842	53,999	28,011	0	1,692,853	1,692,853
September-12	958,055	267,382	50,226	29,993	0	1,305,657	1,305,657
October-12	788,150	259,119	48,387	31,785	0	1,127,441	1,127,441
November-12	825,031	247,193	45,973	33,871	0	1,152,067	1,152,067
December-12	1,088,897	260,785	48,062	36,505	0	1,434,249	1,434,249
January-13	1,178,657	290,830	50,478	38,068	0	1,558,033	1,558,033
February-13	979,421	254,564	44,631	34,891	0	1,313,507	1,313,507
March-13	908,983	252,774	43,972	32,238	0	1,237,967	1,237,967
April-13	729,752	226,718	40,193	32,192	0	1,028,855	1,028,855
May-13	762,154	243,051	43,774	28,999	0	1,077,979	1,077,979
June-13	985,058	262,955	46,985	27,795	0	1,322,793	1,322,793
July-13	1,302,396	281,822	50,112	27,213	0	1,661,542	1,661,542
August-13	1,301,848	280,548	49,780	28,019	0	1,660,195	1,660,195
September-13	939,283	262,176	46,516	29,996	0	1,277,971	1,277,971
October-13	767,549	254,927	45,061	31,781	0	1,099,318	1,099,318
November-13	799,747	243,238	42,914	33,862	0	1,119,762	1,119,762
December-13	1,059,670	257,648	45,161	36,495	0	1,398,975	1,398,975
January-14	1,143,551	287,282	47,537	38,059	0	1,516,429	1,516,429
February-14	949,239	252,041	42,222	34,884	0	1,278,387	1,278,387
March-14	880,321	250,824	41,799	32,237	0	1,205,181	1,205,181
April-14	701,690	223,852	38,103	32,104	0	995,749	995,749
May-14	740,067	242,191	42,010	29,007	0	1,053,276	1,053,276

Contract Month	Projected Monthly Volume Requirements						
	DS1 MWH	DS2 MWH	DS3a MWH	DS5 MWH	QF MWH	Total Load MWH	Net Load MWH
June-14	962,988	262,218	45,112	27,804	0	1,298,121	1,298,121
July-14	1,271,098	279,848	47,915	27,221	0	1,626,081	1,626,081
August-14	1,270,532	278,529	47,576	28,024	0	1,624,661	1,624,661
September-14	914,825	260,436	44,468	29,996	0	1,249,725	1,249,725
October-14	744,074	253,389	43,091	31,778	0	1,072,331	1,072,331
November-14	769,651	240,692	40,845	33,856	0	1,085,044	1,085,044
December-14	1,021,744	255,390	43,049	36,487	0	1,356,670	1,356,670
January-15	1,083,217	284,295	45,229	38,052	0	1,450,793	1,450,793
February-15	899,820	249,903	40,229	34,881	0	1,224,832	1,224,832
March-15	828,459	246,753	39,504	32,237	0	1,146,953	1,146,953
April-15	664,110	220,995	36,130	32,108	0	953,342	953,342
May-15	706,854	240,069	39,989	29,012	0	1,015,925	1,015,925
June-15	920,582	258,925	42,784	27,811	0	1,250,103	1,250,103
July-15	1,222,520	276,967	45,523	27,226	0	1,572,236	1,572,236
August-15	1,219,573	275,599	45,177	28,027	0	1,568,376	1,568,376
September-15	877,732	257,857	42,237	29,996	0	1,207,822	1,207,822
October-15	709,925	251,079	40,947	31,775	0	1,033,726	1,033,726
November-15	728,834	238,165	38,745	33,851	0	1,039,595	1,039,595
December-15	963,638	252,018	40,718	36,482	0	1,292,855	1,292,855
January-16	1,039,801	279,646	42,628	38,047	0	1,400,121	1,400,121
February-16	902,252	251,275	38,732	34,880	0	1,227,139	1,227,139
March-16	805,144	245,573	37,640	32,236	0	1,120,593	1,120,593
April-16	639,739	217,990	34,105	32,110	0	923,945	923,945
May-16	686,061	237,884	37,909	29,017	0	990,871	990,871

ATTACHMENT C: Ameren Illinois Utilities System Supply Requirements Forecast for Five Year Planning Period, June 2011 through May 2016

Ameren Illinois Utilities System Supply Requirements Forecast for Five Year Planning Period, June 2011 through May 2016

Contract Month	Total Load (MWh)		Average Load (MW)	
	On-Peak	Off-Peak	On-Peak	Off-Peak
June-11	714,720	637,904	2,030	1,733
July-11	842,292	858,431	2,632	2,025
August-11	936,346	759,739	2,544	2,021
September-11	678,542	626,958	2,019	1,633
October-11	554,176	575,166	1,649	1,410
November-11	581,246	571,323	1,730	1,488
December-11	688,896	753,821	2,050	1,848
January-12	757,415	821,142	2,254	2,013
February-12	690,534	681,116	2,055	1,892
March-12	617,537	636,963	1,754	1,625
April-12	513,687	520,172	1,529	1,355
May-12	552,358	526,917	1,569	1,344
June-12	721,373	628,422	2,147	1,637
July-12	846,581	847,855	2,520	2,078
August-12	934,121	758,732	2,538	2,018
September-12	590,427	715,229	1,942	1,719
October-12	588,677	538,764	1,600	1,433
November-12	569,373	582,694	1,695	1,517
December-12	647,629	786,621	2,024	1,855
January-13	782,227	775,807	2,222	1,979
February-13	660,503	653,004	2,064	1,855
March-13	584,475	653,492	1,740	1,602
April-13	534,127	493,445	1,517	1,341
May-13	550,200	527,779	1,563	1,346
June-13	666,018	656,776	2,081	1,642
July-13	875,822	785,720	2,488	2,004
August-13	884,335	775,860	2,512	1,979
September-13	604,336	673,635	1,889	1,684
October-13	575,499	523,819	1,564	1,393
November-13	523,916	595,846	1,637	1,490
December-13	655,250	743,725	1,950	1,823
January-14	753,440	762,990	2,140	1,946
February-14	645,123	633,263	2,016	1,799
March-14	563,024	642,157	1,676	1,574
April-14	513,469	482,279	1,459	1,311
May-14	508,863	544,413	1,514	1,334

Contract Month	Total Load (MWh)		Average Load (MW)	
	On-Peak	Off-Peak	On-Peak	Off-Peak
June-14	673,015	625,106	2,003	1,628
July-14	874,495	751,586	2,484	1,917
August-14	820,248	804,413	2,441	1,972
September-14	627,230	622,495	1,867	1,621
October-14	572,087	500,244	1,555	1,330
November-14	476,487	608,557	1,567	1,463
December-14	675,846	680,824	1,920	1,737
January-15	678,828	771,965	2,020	1,892
February-15	611,418	613,414	1,911	1,743
March-15	561,592	585,360	1,595	1,493
April-15	491,677	461,665	1,397	1,255
May-15	465,208	550,717	1,454	1,299
June-15	671,165	578,938	1,907	1,573
July-15	882,955	689,281	2,399	1,833
August-15	780,321	788,055	2,322	1,932
September-15	626,649	581,173	1,865	1,513
October-15	535,815	497,911	1,522	1,270
November-15	486,507	553,087	1,520	1,383
December-15	651,210	641,644	1,850	1,637
January-16	620,555	779,565	1,939	1,839
February-16	615,356	611,783	1,831	1,699
March-16	584,524	536,069	1,588	1,426
April-16	458,246	465,699	1,364	1,213
May-16	478,257	512,614	1,423	1,256

ATTACHMENT D: Ameren Illinois Utilities Contract Volumes to Secure in 2011-2016 Procurement Cycles

Ameren Illinois Utilities Off Peak Contract Volumes to Secure in 2011–2016 Procurement Cycles

Contract Month	Off-Peak Contract Volumes to Secure (MW)						
	Projected Volume (MW)	Swap Volumes (MW)	2010 Procurement Volumes (MW)	Residual Volumes (MW)	2011 IPA Procurement (MW)	2012 IPA Procurement (MW)	2013 IPA Procurement (MW)
June-11	1,733	1,000	250	483	500	0	0
July-11	2,025	1,000	600	425	400	0	0
August-11	2,021	1,000	550	471	450	0	0
September-11	1,633	1,000	200	433	450	0	0
October-11	1,410	1,000	50	360	350	0	0
November-11	1,488	1,000	150	338	350	0	0
December-11	1,848	1,000	400	448	450	0	0
January-12	2,013	1,000	550	463	450	0	0
February-12	1,892	1,000	400	492	500	0	0
March-12	1,625	1,000	200	425	400	0	0
April-12	1,355	1,000	0	355	350	0	0
May-12	1,344	1,000	0	344	350	0	0
June-12	1,637	1,000	0	637	150	500	0
July-12	2,078	1,000	0	1,078	450	650	0
August-12	2,018	1,000	0	1,018	400	600	0
September-12	1,719	1,000	0	719	200	500	0
October-12	1,433	1,000	0	433	0	450	0
November-12	1,517	1,000	0	517	50	450	0
December-12	1,855	1,000	0	855	300	550	0
January-13	1,979	0	750	1,229	650	600	0
February-13	1,855	0	700	1,155	600	550	0
March-13	1,602	0	600	1,002	500	500	0
April-13	1,341	0	500	841	450	400	0
May-13	1,346	0	500	846	450	400	0
June-13	1,642	0	0	1,642	550	600	500
July-13	2,004	0	0	2,004	700	700	600
August-13	1,979	0	0	1,979	700	700	600
September-13	1,684	0	0	1,684	600	600	500
October-13	1,393	0	0	1,393	500	500	400
November-13	1,490	0	0	1,490	500	550	450
December-13	1,823	0	0	1,823	650	650	500
January-14	1,946	0	0	1,946	700	650	600
February-14	1,799	0	0	1,799	650	600	550
March-14	1,574	0	0	1,574	550	550	450
April-14	1,311	0	0	1,311	450	450	400
May-14	1,334	0	0	1,334	450	500	400

Contract Month	Off-Peak Contract Volumes to Secure (MW)						
	Projected Volume (MW)	Swap Volumes (MW)	2010 Procurement Volumes (MW)	Residual Volumes (MW)	2011 IPA Procurement (MW)	2012 IPA Procurement (MW)	2013 IPA Procurement (MW)
June-14	1,628	0	0	1,628	0	550	600
July-14	1,917	0	0	1,917	0	650	700
August-14	1,972	0	0	1,972	0	700	700
September-14	1,621	0	0	1,621	0	550	600
October-14	1,330	0	0	1,330	0	450	500
November-14	1,463	0	0	1,463	0	500	500
December-14	1,737	0	0	1,737	0	600	600
January-15	1,892	0	0	1,892	0	650	650
February-15	1,743	0	0	1,743	0	600	600
March-15	1,493	0	0	1,493	0	500	550
April-15	1,255	0	0	1,255	0	450	450
May-15	1,299	0	0	1,299	0	450	450
June-15	1,573	0	0	1,573	0	0	550
July-15	1,833	0	0	1,833	0	0	650
August-15	1,932	0	0	1,932	0	0	700
September-15	1,513	0	0	1,513	0	0	550
October-15	1,270	0	0	1,270	0	0	450
November-15	1,383	0	0	1,383	0	0	500
December-15	1,637	0	0	1,637	0	0	550
January-16	1,839	0	0	1,839	0	0	650
February-16	1,699	0	0	1,699	0	0	600
March-16	1,426	0	0	1,426	0	0	500
April-16	1,213	0	0	1,213	0	0	400
May-16	1,256	0	0	1,256	0	0	450

Ameren Illinois Utilities Peak Contract Volumes to Secure in 2011 – 2016 Procurement Cycles

Contract Month	Peak Contract Volumes to Secure (MW)						
	Projected Volume (MW)	Swap Volumes (MW)	2010 Procurement Volumes (MW)	Residual Volumes (MW)	2011 IPA Procurement (MW)	2012 IPA Procurement (MW)	2013 IPA Procurement (MW)
June-11	2030	1000	550	480	500	0	0
July-11	2895	1000	1150	745	750	0	0
August-11	2799	1000	1100	699	700	0	0
September-11	2019	1000	500	519	500	0	0
October-11	1649	1000	250	399	400	0	0
November-11	1730	1000	300	430	450	0	0
December-11	2050	1000	600	450	450	0	0
January-12	2254	1000	700	554	550	0	0
February-12	2055	1000	500	555	550	0	0
March-12	1754	1000	300	454	450	0	0
April-12	1529	1000	100	429	450	0	0
May-12	1569	1000	150	419	400	0	0
June-12	2147	1000	0	1147	500	650	0
July-12	2772	1000	0	1772	950	800	0
August-12	2792	1000	0	1792	950	850	0
September-12	1942	1000	0	942	350	600	0
October-12	1600	1000	0	600	100	500	0
November-12	1695	1000	0	695	200	500	0
December-12	2024	1000	0	1024	400	600	0
January-13	2222	0	800	1422	0	400	0
February-13	2064	0	750	1314	700	600	0
March-13	1740	0	650	1090	550	550	0
April-13	1517	0	550	967	500	450	0
May-13	1563	0	550	1013	550	450	0
June-13	2081	0	0	2081	750	700	650
July-13	2737	0	0	2737	950	950	850
August-13	2764	0	0	2764	950	1000	800
September-13	1889	0	0	1889	650	650	600
October-13	1564	0	0	1564	550	550	450
November-13	1637	0	0	1637	550	600	500
December-13	1950	0	0	1950	700	650	600
January-14	2140	0	0	2140	750	750	650
February-14	2016	0	0	2016	700	700	600
March-14	1676	0	0	1676	600	550	550
April-14	1459	0	0	1459	500	500	450
May-14	1514	0	0	1514	550	500	450

Contract Month	Peak Contract Volumes to Secure (MW)						
	Projected Volume (MW)	Swap Volumes (MW)	2010 Procurement Volumes (MW)	Residual Volumes (MW)	2011 IPA Procurement (MW)	2012 IPA Procurement (MW)	2013 IPA Procurement (MW)
June-14	2003	0	0	2003	0	700	700
July-14	2733	0	0	2733	0	950	950
August-14	2685	0	0	2685	0	950	950
September-14	1867	0	0	1867	0	650	650
October-14	1555	0	0	1555	0	550	550
November-14	1567	0	0	1567	0	550	550
December-14	1920	0	0	1920	0	650	700
January-15	2020	0	0	2020	0	700	700
February-15	1911	0	0	1911	0	650	700
March-15	1595	0	0	1595	0	550	550
April-15	1397	0	0	1397	0	500	500
May-15	1454	0	0	1454	0	500	500
June-15	1907	0	0	1907	0	0	650
July-15	2639	0	0	2639	0	0	900
August-15	2555	0	0	2555	0	0	900
September-15	1865	0	0	1865	0	0	650
October-15	1522	0	0	1522	0	0	550
November-15	1520	0	0	1520	0	0	550
December-15	1850	0	0	1850	0	0	650
January-16	1939	0	0	1939	0	0	700
February-16	1831	0	0	1831	0	0	650
March-16	1588	0	0	1588	0	0	550
April-16	1364	0	0	1364	0	0	500
May-16	1423	0	0	1423	0	0	500

ATTACHMENT E: Commonwealth Edison Load Forecast for Five Year Planning Period, June 2011 through May 2016

COMMONWEALTH EDISON COMPANY

Load Forecast for Five-Year Planning Period June 2010 – May 2015

July 15, 2009

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I. INTRODUCTION AND SUMMARY

The Public Utilities Act ("PUA") provides that beginning in 2008 electric utilities in Illinois shall provide a range of load forecasts to the Illinois Power Agency ("IPA") by July 15 of each year. The PUA further provides that these load forecasts shall cover the 5-year planning period for the next procurement plan and shall include hourly data representing high-load, low-load and expected-load scenarios for the load of eligible retail customers ("Eligible Retail Customers"). The electric utility is also to provide supporting data and assumptions (220 ILCS 5/16-111.5(d)(2)). This document presents Commonwealth Edison Company's ("ComEd) load forecast for the planning period of June 2010 through May 2015. ComEd will provide the supporting data and assumptions in a separate package of materials.

ComEd's 5-year hourly load forecast ("Forecast") is based on the PUA's definition of Eligible Retail Customers. Eligible Retail Customers include residential and other customers who are entitled to purchase power and energy from ComEd under fixed-price bundled service ("Blended Service") tariffs. Because service to certain classes of non-residential customers has been declared competitive either by statute or by the Illinois Commerce Commission ("ICC"), only those non-residential customers below 100 kW in size are eligible for Blended Service beginning in June 2010.[1] While previous forecasts reflected these known changes in Blended Service eligibility, phase-out provisions within these competitive declarations allowed certain customers to continue to obtain Blended Service through May 31, 2010. That phase-out period will have ended prior to this Forecast period and the net result this year will be to consider the switching opportunities for a smaller group of customers eligible for Blended Service.

Finally, the Forecast includes the effects of energy efficiency and demand response programs, as well as the quantity of renewable energy resources that need to be procured over the period of this Forecast. The Forecast anticipates that these programs will be observed in full compliance with the PUA's requirements, subject to the defined rate impact test.

II. LOAD FORECAST

A. Purpose and Summary

This section of the Forecast provides forecasted energy usage for the Eligible Retail Customers within ComEd's service territory for the 5-year procurement planning period beginning on June 1, 2010. In accordance with Section 16-111.5(b) of the PUA, the Forecast includes a multi- year historical analysis of hourly loads, a review of switching trends and competitive retail market development, a discussion of known and projected changes to future loads and growth forecasts by customer classes. The impacts, if any, of demand response and energy efficiency programs are also addressed.

[1] There is one exception to this statement. The common area accounts for the condominium associations are exempted from this competitive declaration (see Section 16-103.1 of the PUA).

B. Development of the Five-Year Load Forecast (June 1, 2010 – May 31, 2015)

The hourly load analysis provides the means to determine the on -peak and off-peak quantities needed in the procurement process. In presenting the Forecast, this document focuses on average usage or load during the 12 monthly on-peak and off-peak periods during a year. For the purposes of this Forecast, the definitions of the on-peak and off-peak periods are consistent with those commonly used in the wholesale power markets, and on trading platforms such as the New York Mercantile Exchange ("NYMEX") and the Intercontinental Exchange, Inc. ("ICE"). The on-peak period consists of the week day period from 6 a.m. to 10 p.m. CST excluding NERC holidays (this is referred to as the 5X16 peak period). The off-peak period consists of all other hours (this is referred to as the off-peak "wrap"). The Forecast therefore has been summarized as load requirements using the 24 different time periods covered by these standard products. This is the same approach that was presented in past forecasts. The hourly load data is being supplied with the supporting data and assumptions materials.

1. Hourly Load Analysis

a. Multi-year historical analysis of hourly load

The 2009 multi-year historical analysis of hourly load is very similar to the approach used in the 2008 procurement filing. Essentially, the hourly models that were developed last year were updated with another year of customer data and reviewed for fit. The results this year are similar to the previous filing.

The 2009 multi-year historical analysis of load during the 24 monthly on-peak and off-peak periods is based on hourly profile data for the period from January 2004 to March 2009. The profiles are based on statistically significant samples from ComEd's residential and small commercial and industrial ("C&I") customer population. As noted last year, these samples provide the only basis for an analysis of actual historical hourly usage of Eligible Retail Customers because the standard meters currently used for these customers do not record usage on an hourly basis. Further, as discussed in greater detail below, the profiles show clear and stable weather-related usage patterns that are indicative of how residential and small C&I customers use electricity. Thus, the customer load profiles provide reliable information on the historical hourly usage of customers.

Using the hourly load profiles and actual customer aggregate usage, Table II-1 depicts the historical on-peak and off-peak hourly usage of the major customer groups within the Eligible Retail Customers for the period from January 2006 to December 2008.

Table II-1

Load Forecast Table (Historical Detail 2006-2008)

ComEd Historical Actual Sales

Historical Energy Sales in MWh for Eligible Retail Customers (Line Loss Adjusted)

		Residential Load		Watthour		Small Load (0 to 100kW)		Street Lighting Load		Total Load (MWh)	
Year	**Month**	**On-Peak**	**Off-Peak**	**On-Peak**	**Off-Peak**	**On-Peak**	**Off-Peak**	**On-Peak**	**Off-Peak**	**On-Peak**	**Off-Peak**
2006	1	1,256,132	1,374,251	84,681	67,709	481,564	391,036	4,463	10,303	1,826,841	1,843,298
2006	2	1,161,366	1,227,567	81,336	62,544	446,830	339,993	3,983	9,865	1,693,515	1,639,969
2006	2	1,246,506	1,170,307	86,979	59,836	511,103	348,217	3,371	10,401	1,847,960	1,588,761
2006	4	883,139	1,049,491	63,376	53,330	442,887	355,126	2,200	9,608	1,391,601	1,467,555
2006	5	1,041,922	1,154,671	74,321	54,697	493,627	354,870	1,249	10,727	1,611,119	1,574,964
2006	6	1,367,943	1,202,345	78,971	52,171	591,188	383,157	1,762	9,911	2,039,863	1,647,583
2006	7	1,849,638	2,187,719	78,633	63,303	570,238	500,836	1,339	10,577	2,499,848	2,762,435
2006	8	1,853,407	1,570,249	79,281	48,641	677,835	441,188	2,189	10,893	2,612,713	2,070,971
2006	9	945,129	1,065,004	73,838	59,665	477,947	389,067	3,073	10,246	1,499,985	1,523,981
2006	10	1,101,961	1,100,271	76,818	55,208	505,606	364,796	3,766	10,832	1,688,151	1,531,107
2006	11	1,163,770	1,205,908	78,308	60,523	474,375	356,398	4,321	10,518	1,720,774	1,633,347
2006	12	1,278,904	1,537,332	54,003	51,049	487,419	446,154	4,835	8,804	1,825,162	2,043,341
Totals		**15,149,818**	**15,845,113**	**910,544**	**688,677**	**6,160,620**	**4,670,838**	**36,550**	**122,683**	**22,257,532**	**21,327,312**
2007	1	1,457,097	1,468,878	56,674	43,742	583,358	443,717	5,636	13,179	2,102,765	1,969,515
2007	2	1,267,467	1,369,362	36,786	29,412	442,442	345,901	2,778	5,567	1,749,474	1,750,242
2007	2	1,057,784	1,134,928	23,570	18,140	418,035	317,973	2,086	5,513	1,501,476	1,476,554
2007	4	909,275	994,657	19,710	14,900	390,199	297,316	5,324	19,813	1,324,507	1,326,685
2007	5	1,104,862	1,072,495	23,298	16,207	474,806	325,316	3,179	8,800	1,606,145	1,422,818
2007	6	1,440,606	1,435,159	20,885	15,367	502,081	375,267	3,236	8,688	1,966,807	1,834,481
2007	7	1,630,033	1,768,442	28,412	21,906	526,360	418,045	3,520	8,725	2,188,325	2,217,117
2007	8	2,011,503	1,691,894	26,597	16,913	598,902	385,432	3,660	9,379	2,640,661	2,103,618
2007	9	1,244,723	1,497,186	20,857	18,610	457,852	392,067	4,430	8,737	1,727,862	1,916,600
2007	10	1,142,776	1,173,411	21,873	14,996	467,438	312,726	5,506	9,616	1,637,593	1,510,749
2007	11	785,173	844,163	14,842	11,558	291,515	222,695	5,428	9,193	1,096,958	1,087,609
2007	12	1,440,058	1,821,833	27,331	26,082	469,111	439,096	6,848	10,309	1,943,347	2,297,320
Totals		**15,491,357**	**16,272,407**	**320,836**	**247,833**	**5,622,099**	**4,275,550**	**51,629**	**117,517**	**21,485,920**	**20,913,307**
2008	1	1,411,279	1,483,772	29,148	23,056	466,843	361,907	6,297	10,557	1,913,567	1,879,292
2008	2	1,318,731	1,342,790	26,989	21,401	443,650	337,946	5,615	9,295	1,794,986	1,711,432
2008	3	1,092,187	1,305,371	23,682	21,257	409,987	350,785	4,030	6,004	1,529,885	1,683,417
2008	4	1,011,328	1,006,047	21,714	16,003	427,661	300,578	4,163	8,288	1,464,865	1,330,916
2008	5	886,256	1,047,507	17,377	14,660	392,652	317,448	2,424	3,392	1,298,709	1,383,007
2008	6	1,319,145	1,400,770	21,381	16,263	481,461	364,433	692	7,997	1,822,679	1,789,463
2008	7	1,832,155	1,649,107	24,545	16,852	553,938	391,569	392	2,338	2,411,030	2,059,866
2008	8	1,489,004	1,620,019	23,926	18,615	507,114	406,990	890	4,645	2,020,934	2,050,269
2008	9	1,088,190	1,166,101	19,823	15,684	457,734	341,009	1,268	4,339	1,567,015	1,527,133
2008	10	1,081,333	1,003,909	23,739	16,888	426,681	295,683	1,773	4,603	1,533,526	1,321,083
2008	11	1,021,535	1,335,393	26,766	25,996	381,408	366,260	1,905	4,363	1,431,614	1,732,012
2008	12	1,504,635	1,541,136	31,715	26,073	469,006	382,791	1,848	3,530	2,007,204	1,953,531
Totals		**15,055,778**	**15,901,921**	**290,805**	**232,748**	**5,418,134**	**4,217,399**	**31,296**	**69,352**	**20,796,014**	**20,421,420**

Table II-2 carries forward the total load in MWhs from Table II-1 and then provides the average load for each period in MWs, which is useful in determining the required volume of standard wholesale energy products.

Table II-2

Load Forecast Table (Historical Summary 2006-2008)

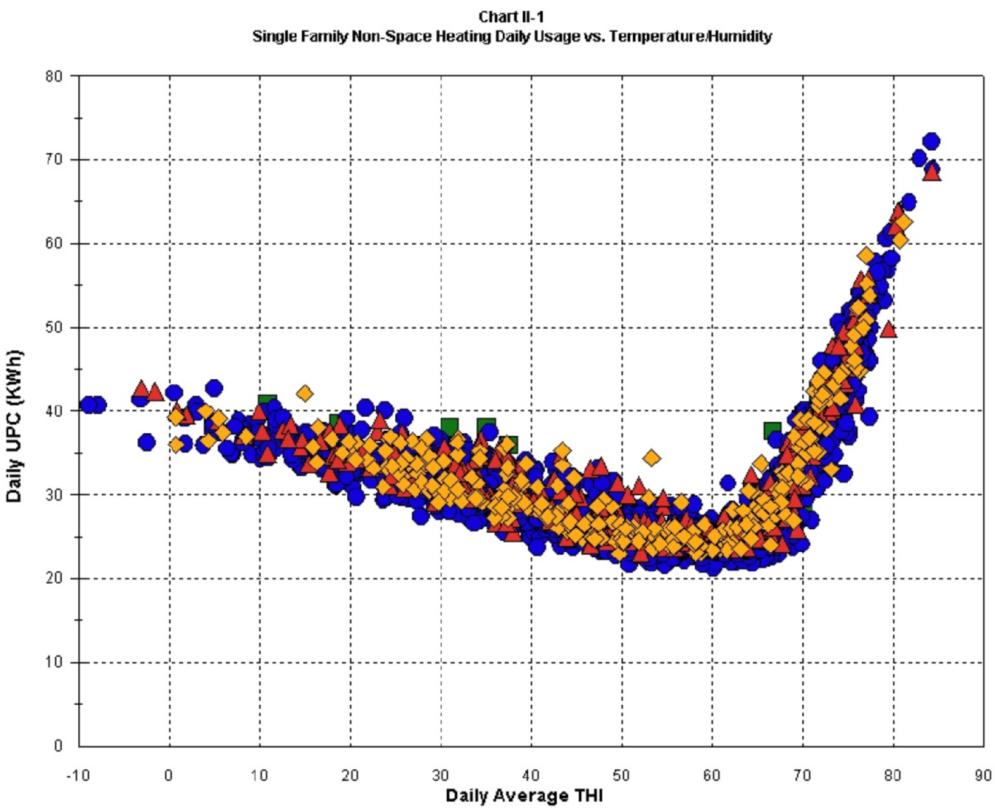
ComEd Historical Actual Sales
Historical Energy Sales for Eligible Retail Customers
(Line Loss Adjusted)

Year	Month	Total Load (MWh) On-Peak	Total Load (MWh) Off-Peak	Average Load (MW) On-Peak	Average Load (MW) Off-Peak
2006	1	1,826,841	1,843,298	5,437	4,518
2006	2	1,693,515	1,639,969	5,292	4,659
2006	3	1,847,960	1,588,761	5,022	4,225
2006	4	1,391,601	1,467,555	4,349	3,669
2006	5	1,611,119	1,574,964	4,577	4,018
2006	6	2,039,863	1,647,583	5,795	4,477
2006	7	2,499,848	2,762,435	7,812	6,515
2006	8	2,612,713	2,070,971	7,100	5,508
2006	9	1,499,985	1,523,981	4,687	3,810
2006	10	1,688,151	1,531,107	4,796	3,906
2006	11	1,720,774	1,633,347	5,121	4,254
2006	12	1,825,162	2,043,341	5,704	4,819
Total		**22,257,532**	**21,327,312**		
2007	1	2,102,765	1,969,515	5,974	5,024
2007	2	1,749,474	1,750,242	5,467	4,972
2007	3	1,501,476	1,476,554	4,266	3,767
2007	4	1,324,507	1,326,685	3,942	3,455
2007	5	1,606,145	1,422,818	4,563	3,630
2007	6	1,966,807	1,834,481	5,854	4,777
2007	7	2,188,325	2,217,117	6,513	5,434
2007	8	2,640,661	2,103,618	7,176	5,595
2007	9	1,727,862	1,916,600	5,684	4,607
2007	10	1,637,593	1,510,749	4,450	4,018
2007	11	1,096,958	1,087,609	3,265	2,832
2007	12	1,943,347	2,297,320	6,073	5,418
Total		**21,485,920**	**20,913,307**		
2008	1	1,913,567	1,879,292	5,436	4,794
2008	2	1,794,986	1,711,432	5,342	4,754
2008	3	1,529,885	1,683,417	4,553	4,126
2008	4	1,464,865	1,330,916	4,162	3,617
2008	5	1,298,709	1,383,007	3,865	3,390
2008	6	1,822,679	1,789,463	5,425	4,660
2008	7	2,411,030	2,059,866	6,850	5,255
2008	8	2,020,934	2,050,269	6,015	5,025
2008	9	1,567,015	1,527,133	4,664	3,977
2008	10	1,533,526	1,321,083	4,167	3,514
2008	11	1,431,614	1,732,012	4,709	4,163
2008	12	2,007,204	1,953,531	5,702	4,983
Totals		**20,796,014**	**20,421,420**		

ComEd analyzed the hourly load profiles for all the major customer groups within the Eligible Retail Customers. As a result of that analysis, ComEd developed hourly load models for those major customer groups that determined the average percentage of monthly sales that each customer group used in each hour of that month. Those hourly models were then used to develop the monthly on-peak and off-peak usage percentages for the planning periods. These percentages were applied to ComEd's forecasted monthly sales to obtain the forecasted procurement quantities that are presented later in this Forecast (see Chart II-7 and the discussion in section IIB(1)(d), below). In the following section, the hourly analysis of the residential single-family non-space heating customer segment is described. This class represents approximately half of the annual sales of the Eligible Retail Customer segment and provides a good example of how the hourly load profile data were analyzed and modeled.

(i) Residential Single-Family Hourly Load Profile Analysis

One of the most significant, and easily understood, determinants of residential energy usage is weather. The "scatter plot" shown below (Chart II-1) demonstrates the significant relationship that exists between weather and usage for the single-family non-space heating residential customer segment.



A scatter plot shows the relationship between two variables. Each point represents a single observation (a day in this case). In this chart, the values shown on the vertical or Y-axis are daily usage per customer ("UPC"). The values shown on the horizontal or X-axis

are the daily average temperature-humidity index ("THI"). The graph shows daily UPC based on observations from June 2002 to March 2009 and the average THI on those days. THI, rather than temperature alone, is used because residential usage is sensitive to humidity. Different geometric shapes are used to distinguish points representing weekdays from those depicting Saturday, Sunday or holiday usage.

The scatter plot is very useful in understanding the relationship between customer usage and weather. If there were no relationship between the two, points on the graph would not display a clear pattern. However, it is apparent that there is a clear pattern. The right side of the graph at the high end of the horizontal axis shows the days on which THI was the highest. The points at that end of graph indicate that the highest UPC occurred when THI levels were at their peak -- 80 plus degrees. Moving to the left, the points show UPC declining rapidly as the THI decreases until the 60 degree level is reached at which a base usage appears. From that base level, UPC gradually increases as colder temperatures are experienced.[2]

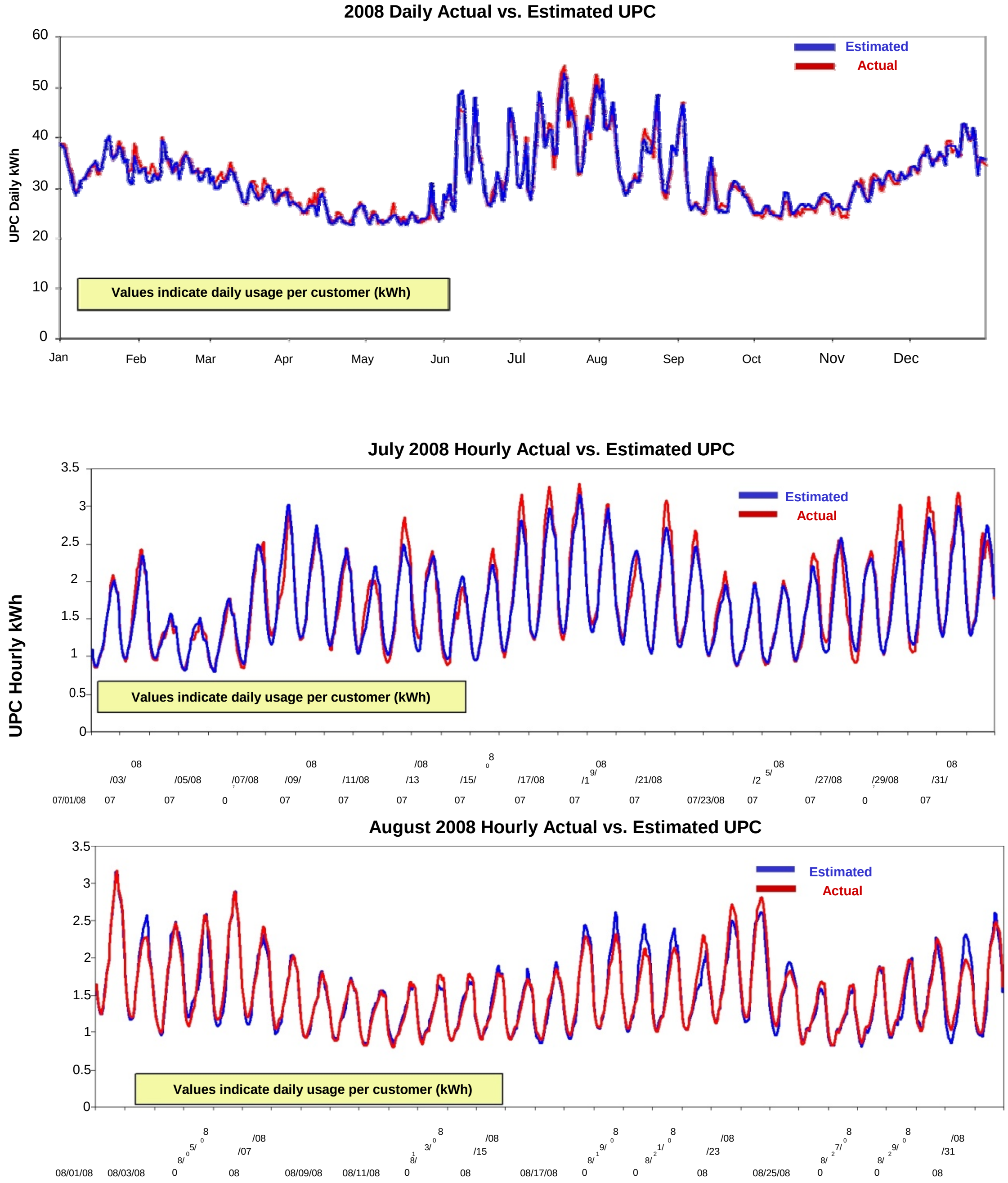
Hourly models were developed to account for the strong weather relationship shown in the graph and to account for numerous other factors that influence residential usage. The models explicitly account for the differing effects of energy use at various temperatures. Variables are included to allow for seasonal usage patterns in water heating, refrigeration and other seasonal uses. Weekend and holiday variables are included to allow for behavioral differences on those days relative to weekdays. The amount of daylight on each day is included to account for seasonal differences in lighting loads. Weather variables for prior days are included in the model to account for the dynamic effects of temperature buildup. The full list of variables included in the residential single-family model is shown in Appendix A-1.

One way to visualize the model's performance is to look at plots of actual and estimated[3] values for the historical estimation period. The following chart demonstrates the performance of the model over the one-year period from January 2008 through December 2008 at the daily level and zooms in to show the hourly performance in July and August of 2008.

[2] Unlike usage for commercial customers, residential daily usage does not vary significantly between weekdays and weekends. In fact, residential usage on weekends and holidays is typically greater than on week days.

[3] The estimated data in Chart II-2 is based on the actual weather experienced over the relevant period.

Chart II-2
ComEd Single Family Profile: Estimated vs. Actual



In all of the three above graphs in Chart II-2, the red line indicates the "actual" load data and the blue line indicates the model's estimated values, based on actual weather. In this case, it is important to understand that the actual data are themselves estimates of population loads based on a statistical sample, and are therefore subject to minor variations that occur in the sample. Despite this statistical variation in the actual values, the charts demonstrate that the model's estimated usage and the actual usage are extremely close. The close alignment of the estimated and actual lines on the charts demonstrates that the model is very effective in determining variations in electrical usage patterns.

b. Switching Trends and Competitive Retail Market Analysis

In determining the expected load requirements for which standard wholesale products will have to be purchased, it is important to provide the best possible forecast of the extent to which Eligible Retail Customers are likely to switch to alternative providers. That issue is considered in the following discussion, which reviews retail development in ComEd's service territory, the entry of alternative suppliers, the rate of customer switching in the past, future trends affecting customer choice and ComEd's 5-year forecast of the percentage of load from various customer segments that will remain to be served with supply procured by ComEd.

(i) Introduction and Brief Overview of Retail Development

There can be no doubt that robust retail markets exist in northern Illinois. In October 1999 the first ComEd customer began taking service from an alternative retail electric supplier ("RES"). In the following ten years there has been a steady movement to RES service. As of May 2009 only 21% of ComEd's entire non-residential sales were being served under Blended Service (the traditional utility fixed rate). By June 2010 that figure is estimated to be below 14% as the over 100 kW customers migrate off of Blended Service and small commercial customers below 100 kW opt for RES service. Thus, the ComEd non- residential market has gone from no retail activity ten years ago to one now approaching 90% of the non-residential sales being served by a RES or Hourly Service.

While customer switching in the commercial and industrial market has been very robust, customer switching in the Residential class has been much slower. There are many factors that contribute to this condition, with acquisition costs, market conditions and modest price changes for residential customers being primary factors. Over the past 12 years the average residential rate is largely unchanged, 11.6 cents/kWh in 2008 versus 11.4 cents/kWh in 1996. Thus, rapid price escalation that might have caused residential customers to seek RES service has not occurred.

In summary, retail choice is a success story in the ComEd service territory. While this phenomena is subject to a variety of factors, especially market conditions, a healthy retail market is anticipated in the near term.

(ii) RES Development

The success of retail market competition is the result of the concerted efforts of ComEd, numerous RESs and policy makers. Today, the retail market development continues in two very meaningful ways. First, RESs continue to enter the ComEd market. Since January 2008 eight new RESs have been certified by the ICC. Five of the eight have been registered by ComEd to serve retail load and the remaining three are in the process. Second, as noted last year, ongoing workshops are occurring related to purchase of receivables ("POR"). The POR topic is addressed in more detail with the "Future Trends" section below.

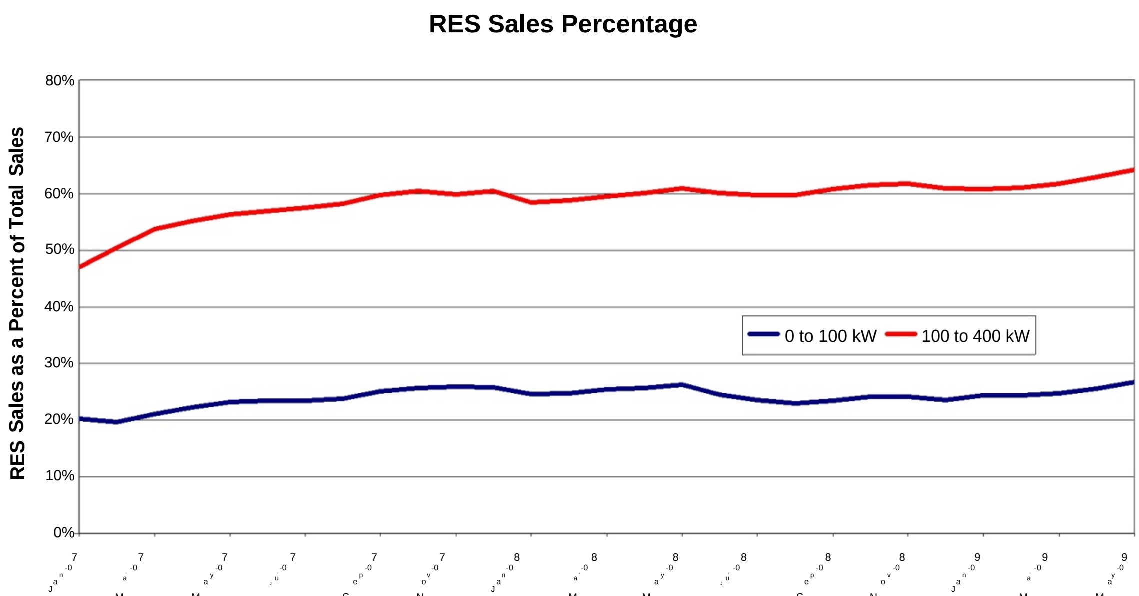
Just like ComEd's customer base, there is a large and very diverse population of RESs in northern Illinois. These companies differ in many ways. Some have national operations while others operate just regionally. Some are focused on the entire spectrum of customers, including residential, while others concentrate on just non-residential customers. Some retailers offer other products (e.g., demand response) to assist the customer in managing their electricity usage. This large number of diverse businesses can only be considered a plus to the customers in the ComEd service territory.

It is interesting to note that during one of the most severe recessions in the country's history there has been only one RES that has left the ComEd market in the past year. Another RES surrendered its ARES certification, although they were not registered with ComEd. On the other hand, one RES in our service territory was recently selected by Crain's Chicago Business as the fastest growing small business in the Chicago area.

(iii) Future Trends

RES sales to the 0 to 100 kW customers has been gradually growing over time. Chart II -3 contains monthly RES percentage of sales from January 2007 through May 2009 for the 0 to 100 and 100 to 400 kW customers (though not applicable for this procurement event). The 0 to 100 kW RES sales have been slowly growing over time. RES sales to the 100 to 400 group has been increasing at a faster pace than the 0 to 100 kW group. This is understandable given, among other things, the expiration of Blended Service to this group as of June 2010. The view is that movement by the 100 to 400 kW customers will increase migration by some of the 0 to 100 kW customers. Thus, the outlook is for the 0 to 100 kW customers to continually migrate to RES service, but at a slightly faster pace than in the past few years.

Chart II-3



In assessing future small C&I and residential RES sales, consideration needs to be given to the potential impact of the ongoing discussion concerning POR. A POR program could result in greater participation by RESs in the residential retail market by lowering a RES' costs.

Discussions are currently underway to address implementation issues, and the programs are expected to become operational in the January to March 2011 time frame.

Another development that has some potential to affect the level of Blended Service sales to residential and Small C&I customers is House Bill 722 ("HB722"). That bill passed both houses of the Illinois General Assembly and is awaiting execution by the Governor. HB722 revises Section 17-800 of the PUA by allowing a municipality to adopt an opt-out aggregation program. These revisions have some potential to lessen Blended Service sales to the residential and small C&I customers, but their effect is too uncertain to be taken into account for purposes of this Forecast.

(iv) Forecasted Retail Sales

The forecast percentages of Blended Service sales are shown below, along with some historical perspective.

Table II-3
Percentage of Blended Service Sales[4]

Month	Residential	Watthour	0-100 kW
Jun-04	100.0%	99.4%	87.8%
Jul-05	100.0%	99.4%	87.3%
Jul-06	100.0%	99.6%	90.7%
Jul-07	100.0%	97.4%	76.5%
Jun-08	99.9%	98.0%	75.2%
May-09	99.8%	98.0%	72.1%
Jun-10	99.5%	96.0%	65.1%
Jun-11	98.3%	96.0%	55.4%
Jun-12	98.3%	96.0%	55.4%
Jun-13	98.2%	96.0%	55.4%
Jun-14	98.2%	96.0%	55.4%
Jun-15	98.2%	96.0%	55.4%

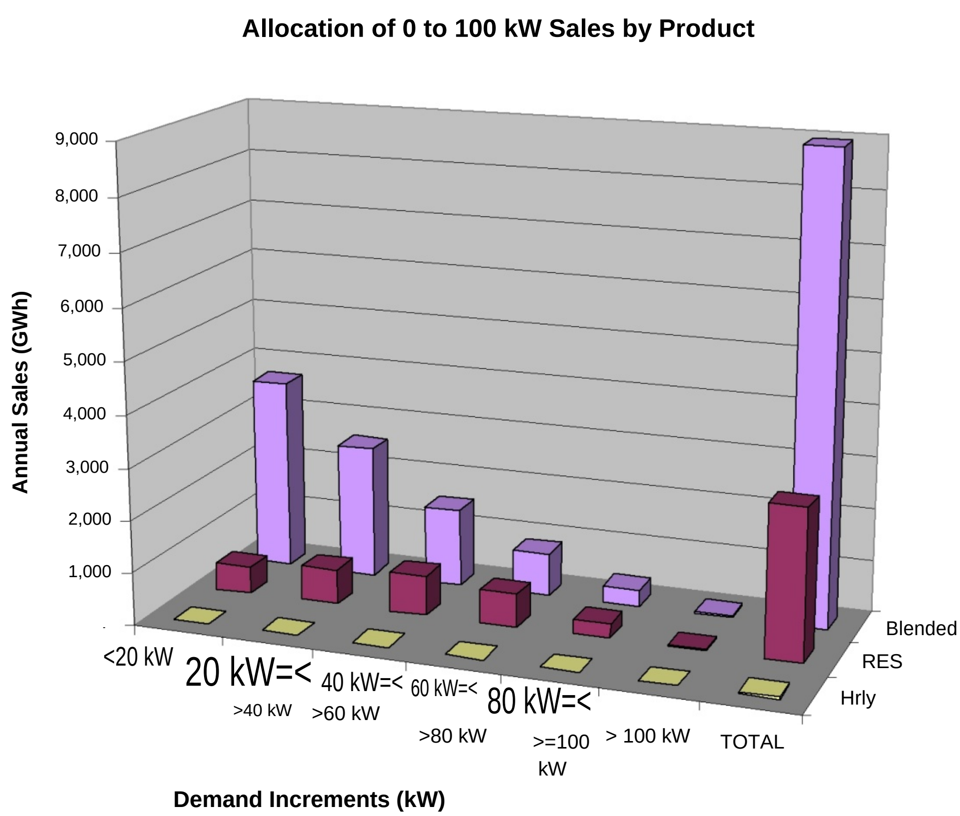
[4] For the 2004 to 2006 data the percentages may include a very minor amount of sales related to customers taking service under ComEd's hourly service tariffs.

The main drivers of this forecast are:

1. The Blended Service supply cost will reflect certain pre-existing contracts; specifically the financial swap agreement that is in place through May 2013. If market prices continue to be lower than they have been in the last few years, this may produce some "headroom" that provides the opportunity for more RES sales in the 0 to 100 kW customer group or for customers to switch to Hourly Service.

2. In addition, a gradual increase in RES sales to the non-residential customers below 100 kW is assumed as retailers continue to seek new customers. This has been the pattern for the past decade. However, the increase in RES service to the below 100 kW non-residential customers is limited by the fact that many of the customers in this category are rather small in size (i.e., almost "watt-hour like" in size). Below is a chart depicting the allocation of sales (kWh) to the 0 to 100 kW customer group among Blended, RES and Hourly products for the year 2008. The chart breaks down this customer group by 20 kW increments. A large portion of the Blended usage in this class is in the below 40 kW segments. While RES have been able to obtain customers in the below 40 kW segments, their share accounts for only 15% of the total below 40 kW sales. This highlights the difficulty in RESs reaching customers whose electricity bill is relatively small.

Chart II-4



3. Residential switching is not assumed to occur for the next couple of years, but a small amount is expected in later years as a result of the POR initiative.

The effects of those drivers by customer group are as follows:

1. The RES served portion of the 0 to 100 kW customer load will grow from 27% (as of May 2009) to 34% by June 2010. This movement is helped by the current RES marketing efforts related to the 100 to 400 kW customers. POR efforts, potential for headroom and RESs seeking new customers causes this percentage to increase to 44% by June 2011. The percentage holds at this level thereafter given the smaller customer size of the remaining Blended customers.

2. Watthour customers are similar in behavior to residential customers when viewed from a choice perspective and their participation in customer choice is expected to generally mimic the residential movement. Approximately 98% of the total sales to these customers are for Blended Service and that percentage decreases slightly to 96% during the Forecast period.

3. Active residential customer choice is not assumed to occur until 2011 because of the same Blended Service pricing dynamics noted for the small non-residential customers. Beginning in 2011 a small amount (i.e., 0.2-0.4% of total residential sales) is anticipated as POR initiatives are implemented. However, increasing residential hourly sales are anticipated in the Forecast and addressed in the next section.

c. Known or Projected Changes to Future Load

Typically, when ComEd forecasts future loads, it considers whether there are any known major customer decisions, such as the relocation of part or all of a business, that would impact load. For the Eligible Retail Customers, other than the factors we have discussed elsewhere, e.g. switching, energy efficiency measures, growth, etc., there is only one known or projected change that ComEd is aware of that would affect future loads for this group of customers. This is the residential real-time pricing program ("RRTP").

In compliance with Section 16-107(b-5) of the PUA, ComEd received ICC approval to implement an RRTP program.[5] ComEd currently has about 7,000 customers on RRTP and is targeting just over 11,000 by the end of 2009. In addition, ComEd expects about 6,000 additional customers will switch to RRTP in 2010. The program could potentially expand beyond 2010, but is subject to ICC review and approval at the end of the year.

[5] See ICC Order of December 20, 2006, in Docket No. 06-0617.

ComEd is currently seeking approval to implement a smart meter pilot program (ICC Docket no. 09-0263). If approved, ComEd would install 140,000 smart meters by mid-2010. Thus, there is some potential that additional customers could switch to RRTP over the timeframe of this Forecast. However, the number of such customers is small and ComEd does not think it is reasonable to project any additional migration off of Blended Service in this year's Forecast due to the pilot program.

ComEd will also be applying to the Department of Energy ("DOE") for funding under the Smart Grid Investment Grant Program. Under this program, parties can apply for up to $200 million to help cover the costs of deploying smart grid facilities. If ComEd is successful, it plans to deploy additional smart meters in the City of Chicago and also plans to deploy home area network equipment in some of these homes that would permit these customers to have greater control over their energy usage. A decision from DOE is expected in October 2009. While DOE approval is uncertain, to prevent over procurement of energy for Blended customers this forecast assumes 25,000 additional homes do utilize RRTP service beginning in the fourth quarter of 2010. This assumption serves as a placeholder that acknowledges the potential for significant increases in future RRTP customers because of this program while also acknowledging the previously described uncertainties. The timing of DOE decision should permit ComEd to include the effect of this decision in the updated forecast that it intends to submit during the procurement proceeding as it did last year.

The table below shows the combined effect of the RRTP program and of the smart grid program on residential usage over the time period of this Forecast.

Table II-4
RRTP Enrollments and the Amount of Associated Load

End of Year	**Incremental Enrollments**	**Total Enrollments**	**Annual Usage (GWh)**
2009	5,100	11,100	107
2010	31,000	42,100	406
2011	0	42,100	406
2012	0	42,100	406
2013	0	42,100	406
2014	0	42,100	406

Customers that switch to RRTP would no longer be considered in the forecasted load of Eligible Retail Customers. The last column in the above chart depicts the estimated annual usage that would be impacted by this level of RRTP participation using the annual usage of a residential single-family non-space heating customer.

d. Growth Forecast by Customer Class

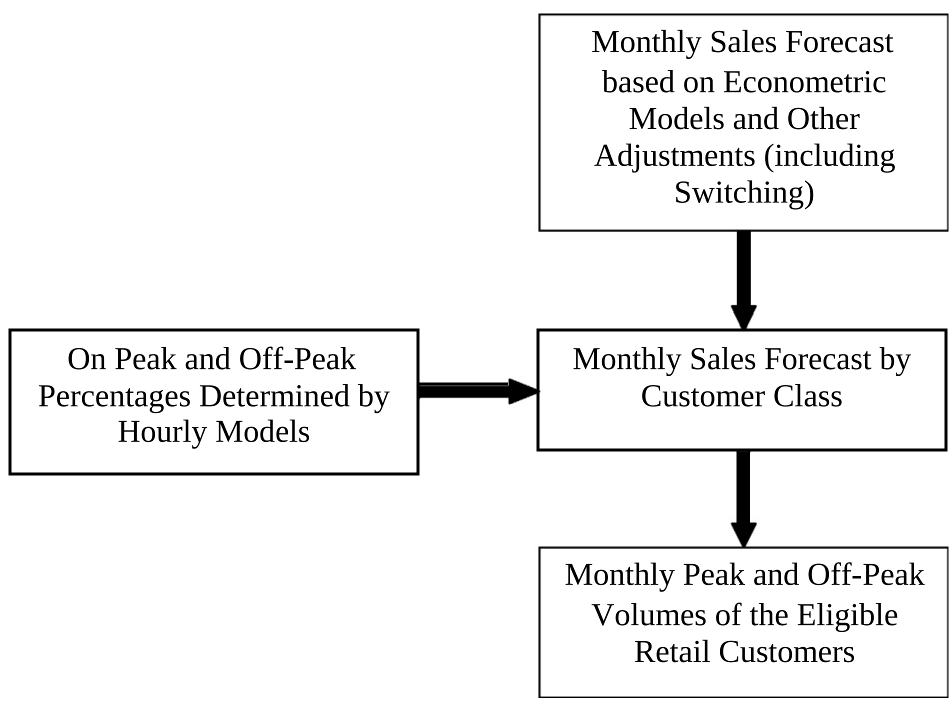
(i) Introduction

This section describes ComEd's growth forecast by customer class for the 5-year procurement planning period beginning on June 1, 2010. Section II(B)(1) discussed the hourly customer load profiles used by ComEd to develop models to present the historical load analysis required by the PUA and to predict average UPC. As indicated in this section, in arriving at a growth forecast by customer class, there are additional models beyond those customer-level hourly models that are used to forecast future customer class sales. These other models play an important role in determining expected load during the 5-year planning period among the Eligible Retail Customer groups.

The following chart illustrates the steps in the ComEd load forecasting process.

Chart II-5

ComEd Energy Sales Forecast Process



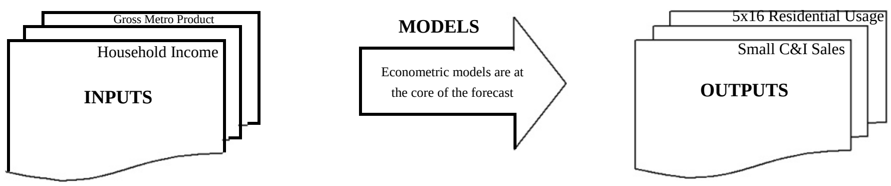
The forecasting process is model based subject to adjustments and judgment. A suite of econometric models is used to produce monthly sales forecasts for ComEd's revenue customer classes. The two major customer classes applicable to this Forecast are Residential and Small C&I. That monthly forecast is adjusted for other considerations (e.g., switching activity) and allocated to more granular delivery service classes (e.g., the residential customer class is

composed of four delivery services classes). The forecast sales are combined with the input from the hourly models to obtain on-peak and off-peak quantities for each month and delivery service class.

The econometric modeling portion of the process is described in the following chart:

Chart II-6

Econometric Modeling Process



Economic Forecasts
- Chicago Gross Metro Product
- Real Income per Household
- Household Growth (Economy.com provides input)

Switching Forecast
- RES Activity
- Market Developments

Top Down Approach
- Zone output modeled using historical weather and economic variables
- Customer class usage modeled using historic weather data and economic variables for each class
- Customer class forecast calibrated to equal zone output forecast (less line loss)
- Other research and judgment used to determine final energy forecast (e.g., effects from new energy efficiency programs)
- Sales forecast adjusted for projected switching activity
- Hourly customer class models used to determine on-peak and off-peak usage

Sales and Load Forecasts
- ComEd Zone Output
- Customer Class Sales
- Procurement Eligible Sales by On-Peak and Off-Peak Usage

As the chart indicates, ComEd's forecasts of sales for its service territory are based on a "top-down" approach. The top-down approach provides a forecast of total sales for the entire service territory and allocates the sales to various customer classes using the models specific to each class. The "zone" forecast model takes into account a number of economic variables that affect electric energy use. For example, the gross metropolitan product ("GMP") for the Chicago and Rockford areas is a good measure of economic activity in ComEd's service territory. As GMP (which is expressed in billions of dollars) increases, use of electric energy rises as well. Similarly, the zone model considers the total number of residential customers in ComEd's service territory. As the number of customers increases, total usage is also affected. Section II (B)(1) describes the significant relationship between weather and energy usage, and the zone model contains sophisticated variables to reflect the effects of temperature and humidity, as well as seasonal usage patterns and other factors. The economic assumptions are contained in Table II-5.

Table II-5

Chicago Area Economic Forecasts - Economy.com (March'09)

Economic Variables	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
Gross Metro Product (Billions)	$ 385	$ 391	$ 389	$ 375	$ 381	$ 399	$ 424	$ 438	$ 447	$ 454
Real Disposable Income (Millions)	$ 292,201	$ 298,713	$ 305,962	$ 304,214	$ 304,448	$ 313,277	$ 323,276	$ 336,380	$ 344,531	$ 354,701
# of Households (Thousands)	3,321	3,344	3,368	3,389	3,413	3,444	3,484	3,517	3,545	3,568
Real Income/HH	$ 87,991	$ 89,328	$ 90,851	$ 89,775	$ 89,211	$ 90,953	$ 92,787	$ 95,638	$ 97,199	$ 99,409
Total Employment (Thousands)	4,443	4,480	4,451	4,232	4,222	4,345	4,514	4,639	4,682	4,709
Non-Manufacturing	3,953	3,996	3,980	3,800	3,799	3,915	4,073	4,189	4,234	4,262
Manufacturing	490	484	471	432	423	430	441	449	449	446

Growth Rate	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
Gross Metro Product	2.5%	1.6%	(0.5%)	(3.5%)	1.7%	4.6%	6.2%	3.5%	1.9%	1.6%
Real Disposable Income	2.4%	2.2%	2.4%	(0.6%)	0.1%	2.9%	3.2%	4.1%	2.4%	3.0%
# of Households	0.6%	0.7%	0.7%	0.6%	0.7%	0.9%	1.2%	1.0%	0.8%	0.7%
Real Income/HH	1.8%	1.5%	1.7%	(1.2%)	(0.6%)	2.0%	2.0%	3.1%	1.6%	2.3%
Total Employment	1.4%	0.8%	(0.7%)	(4.9%)	(0.2%)	2.9%	3.9%	2.8%	0.9%	0.6%
Non-Manufacturing	1.7%	1.1%	(0.4%)	(4.5%)	(0.0%)	3.0%	4.0%	2.9%	1.1%	0.7%
Manufacturing	(1.0%)	(1.1%)	(2.8%)	(8.2%)	(2.0%)	1.5%	2.6%	1.8%	(0.1%)	(0.6%)

Source: Moody's Economy.com

All of the variables used in each of the models in the forecasting process are identified in Appendix A-4.[6]

The remainder of this section will provide a brief description of the models, starting with the ComEd Monthly Zone energy usage model and proceeding to the three customer-level models for Monthly Residential bill-cycle energy usage, Monthly Small C&I bill-cycle energy usage and Monthly Street Lighting bill-cycle energy usage.

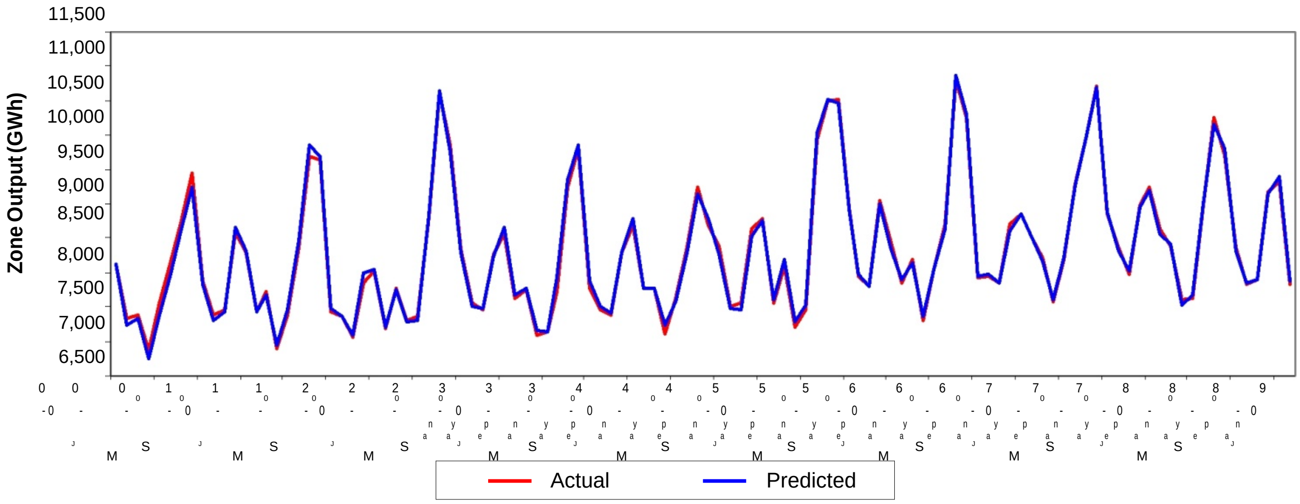
(ii) ComEd Monthly Zone Model

The Monthly Zone model forecasts energy usage in gigawatt hours (GWh) for the entire ComEd service territory. The following chart shows the performance of the ComEd Monthly Zone model by comparing actual zone output to the estimates[7] from the model for each calendar month from 2000 through February 2009.

[6] Technical information about the model coefficients and regression statistics are included in Appendix A-2 and A-3.

[7] Once again, for purposes of this Forecast, the estimates used in Charts II-10, II-11 and II-12 are based on actual weather.

Chart II-7
ComEd Monthly Zone Model: Estimated vs. Actual

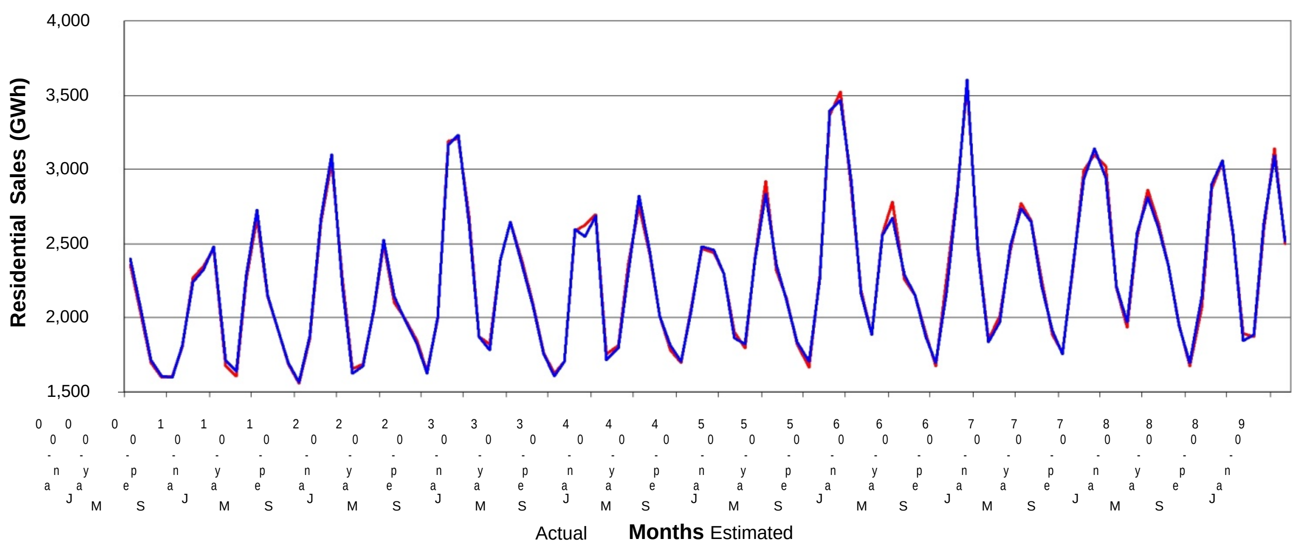


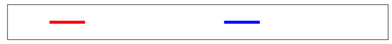
As with customer-level models discussed in Section II(B)(i)(a), the Monthly Zone model is highly useful in understanding energy usage. The graph line depicting the model's estimated usage (based on actual weather) and the line showing actual usage for the period are nearly identical.

(iii) ComEd Monthly Residential Model

The Monthly Residential model forecasts monthly residential bill-cycle sales expressed in kWh per customer per day. The Monthly Residential model is also very useful in understanding energy usage for this customer segment. The following chart compares the monthly energy usage for residential customers estimated by the Monthly Residential model to the actual residential usage for the time period of January 2000 to February 2009.

Chart II-8
ComEd Monthly Residential Model: Estimated vs. Actual





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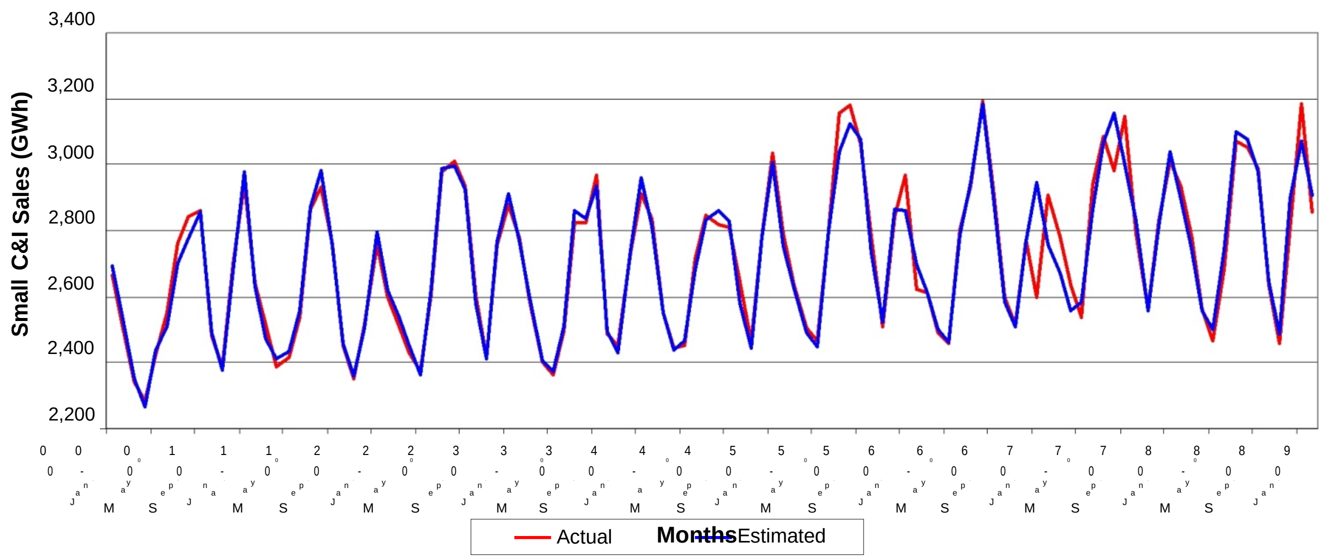
The graph line depicting the model's estimated usage and the line showing actual usage for the period are highly correlated.

(iv) ComEd Monthly Small C&I Model

The Monthly Small C&I model forecasts monthly Small C&I bill-cycle sales. Chart II-9 shows an estimated versus actual comparison demonstrating the model's effectiveness. The larger than normal variance in the period January 2007 to March 2007 is explained by post-2006 billing implementing issues. The transition to the new rates that took effect on January 2, 2007, caused certain retail billing data to lag the actual billing cycle.

Chart II-9
ComEd Monthly Small C&I Model: Estimated vs. Actual



(v) ComEd Monthly Street Light Model

The Monthly Street Lighting model forecasts monthly bill-cycle sales related to street lighting. This final model estimates use per day in GWh.

(vi) Growth Forecast

ComEd's historical and forecasted weather-adjusted energy sales for the residential and small C&I customer classes are shown in Table II-6.

Table II-6

ComEd Weather Adjusted Annual Energy Sales				
	Residential		Small C&I	
Year	**Sales (GWh)**	**Percent Growth**	**Sales (GWh)**	**Percent Growth**
2002	26,162		31,425	
2003	27,079	3.5%	32,885	4.6%
2004	27,905	3.1%	32,733	(0.5%)
2005	28,290	1.4%	33,057	1.0%
2006	28,516	0.8%	32,958	(0.3%)
2007	28,459	(0.2%)	33,508	1.7%
2008	28,599	0.5%	33,392	(0.3%)
2009	28,373	(0.8%)	33,015	(1.1%)
2010	28,439	0.2%	33,264	0.8%
2011	28,809	1.3%	33,732	1.4%
2012	29,219	1.4%	34,346	1.8%
2013	29,349	0.4%	34,541	0.6%
2014	29,416	0.2%	34,624	0.2%

The forecast is consistent with past experience. Residential sales growth has averaged 1.5% per year from 2002 to 2008. The growth in 2009 is (0.5%), after adjusting for 2008 being a leap year. The annual growth rate is lower in the last few years of this Forecast period as the energy efficiency programs that are required by the PUA are implemented. The same is generally true of the Small C&I growth rates. The 2002 to 2008 average growth rate is 1.0% per year. The 2009 growth rate is (0.8%) after adjusting for leap year. Energy efficiency programs also influence future sales in this customer class.

2. Impact of Demand Side and Energy Efficiency Initiatives

The PUA sets out annual targets for the implementation of cost-effective demand side and energy efficiency measures. ComEd believes these targets are achievable and plans to meet them in planning year 2010. The demand -side and energy efficiency plans for subsequent years have not yet been developed by ComEd or approved by the ICC. For purposes of this forecast, we assume that the statutory targets will be met, except for the planning years 2013 and 2014. In those years, the rate cap may limit the total amount of the energy efficiency programs. For purposes of this Forecast, the impacts in 2013 and 2014 are shown in Table II-9.

a. Impact of demand response programs, current and projected

(i) Background

ComEd is a strong supporter of the use of demand response to actively manage peak demands. Use of demand response resources grew in the mid to late 1990s, and ComEd has maintained a large portfolio of demand response resources, with participation from residential, commercial, and industrial customers. ComEd is a nationally recognized leader in the development and management of demand response resources, and will increase participation in appropriate programs to meet the requirements of the PUA.

The current portfolio of ComEd programs include the following:

Direct Load Control ("DLC"): ComEd's residential central air conditioning cycling program (formerly called "Nature First") is a DLC program with over 60,000 customers with a load reduction potential of 105 MW (ComEd Rider AC7).

Voluntary Load Reduction ("VLR") Program: VLR is an energy based demand response program, providing compensation based on the value of energy as determined by the real -time hourly market run by PJM. This program also provides for transmission and distribution ("T&D") compensation, based on the local conditions of the T&D network. This portion of the portfolio has roughly 799 MW of potential load reduction (ComEd Rider VLR7).

Capacity Market Program: Under this program, customers reduce load to a pre-determined level with compensation based on capacity market values from PJM's capacity markets. This program has roughly 432 MW of load reduction potential (ComEd Rider CLR7).

Time-base pricing: All ComEd's customers have an option to elect an hourly, market-based rate. The RRTP Program has operated in the past as ComEd Rate RHEP. This program had roughly 2.9 MW of price response potential.

(ii) Legislative Requirement

Section 12-103(c) of the PUA establishes a goal to implement demand response measures, providing that:

> (c) Electric utilities shall implement cost-effective demand response measures to reduce peak demand by 0.1% over the prior year for eligible retail customers, as defined in Section 16-111.5 of this PUA. This requirement commences June 1, 2008 and continues for 10 years.

Table II-9 shows the estimated annual MWs of demand response measures that will need to be implemented over the Five-year planning period to meet the goals set forth in the PUA:

Table II-7
Estimated Annual Level of Demand Response Measures

Year	Peak Load at Meter (MW)	Annual Goal (MW)	Cumulative Goal (MW)
2010	10,597	10.0	32.8
2011	10,482	10.5	43.3
2012	10,661	10.7	53.9
2013	10,810	10.8	64.8
2014	10,955	11.0	75.7

The cumulative goal includes 11.7 MW for the year 2008 and 11.1 MW for 2009. The 2010 annual goal of 10.0 MW is from the original ICC filing.

The Illinois General Assembly recently passed Senate Bill 2150 ("SB2150"), and that bill is currently waiting to be signed by the Governor. SB2150 revises section 12-103(c) of the PUA to include "customers that elect hourly service from the utility pursuant to Section 16-107 of the PUA, provided those customers have not been declared competitive." Assuming that bill is signed by the Governor, the actual response measures that would need to be implemented to comply with that law would be determined in the next energy efficiency and demand-response plan, covering the planning years 2011-3, that ComEd would file for approval with the ICC pursuant to Section 12-103(f) of the PUA. Thus, this bill will not impact the level of demand response measures that need to be implemented until 2011. If the bill is signed by the Governor, the numbers in the table above for the 2011-4 planning years would be slightly increased.

(iii) Implementation of Demand Response Measures

As required by the PUA (220 ILCS 5/16-103), ComEd filed and received approval for its proposed demand response program for the three-year planning period covering June 2008 through May 2011.[8] The details of that program are provided in the plan that ComEd filed in that docket. ComEd anticipates filing a new plan for the next three-year planning period (i.e., June 2011 through May 2014) sometime in late 2010, as required by the PUA. For purposes of this forecast, ComEd assumes that the statutory targets for demand response programs will be met during the next planning period.

(iv) Impact of Demand Response Programs

Demand response programs do not impact ComEd's load forecasts. Load forecasts are made on a weather normalized, unrestricted basis. Since demand response measures are called on days when the temperature is hotter than "normal", the avoided capacity and energy associated with these resources is incremental to the weather normal forecast, and thus is not factored into the load forecasts. In fact, when developing forecasts, any impact on

[8] See Order of February 6, 2008 in docket No. 07-0540.

energy usage from actually implementing a demand response measure in a prior year is added back into that prior year's usage data and then weather normalized before being used to assist in the forecasting process. This assures that the forecast represents a complete picture of the unrestricted demands on the system.

b. Impact of Energy Efficiency Programs

The PUA requires ComEd to implement cost-effective energy efficiency measures beginning June 1st, 2008. The PUA provides annual kWh targets based on a projection of the upcoming years' energy usage for all delivery service customers. Additionally, there is a spending cap that limits the amount of expenditures on energy efficiency measures in any year. For purposes of the PUA, the energy efficiency year is defined as June through May.

(i) kWh Targets

The kWh target for energy efficiency is based on a projection of the amount of energy to be delivered by ComEd to all of its delivery service customers in the upcoming planning year. This percentage increases annually through the year 2015, subject to specified rate impact criteria. The table below shows the target percentages.

Table II-8
Target Incremental Percentages to Meet Energy Efficiency Goals

Year	Annual Percent Reduction in Energy Delivered
2008	0.2%
2009	0.4%
2010	0.6%
2011	0.8%
2012	1.0%
2013	1.4%
2014	1.8%
2015	2.0%

(ii) Projected Overall Goals

The annual energy efficiency goals were determined based on the kWh targets and the rate impact criteria, as discussed above. As discussed in greater detail in the energy efficiency/demand response plan filed in Docket No. 07-0540, the rate impact criteria are not expected to impact the energy efficiency targets through the 2010 planning year. The energy efficiency/demand response plan addressed only the 2008-2010 planning years, as required by the PUA. Thereafter, for purposes of this Forecast, it is assumed that the rate impact criteria will not affect the achievement of the targets, except, as noted above, for planning year 2013 and

2014. Also, for purposes of this Forecast only,[9] the allocation of the energy (kWh) targets to the various customer classes (as shown in Table II-6) was based on several years of historical data and judgment.

The above numbers represent the incremental goal to be achieved by the end of each planning year for all delivery services customers. Since the various energy efficiency measures will be implemented and phased in over the course of each planning year and since Eligible Retail Customers are only a subset of delivery services customers, the actual amount of GWh for Eligible Retail Customers that is impacted in each planning year will be somewhat less (as shown in Table II-9, below).

(iii) Impact on Forecasts

Energy efficiency measures directly impact the amount of energy used by customers throughout the year. As such, they will directly impact the forecasts of future load. The following chart depicts the cumulative impacts of these measures on the Forecast:

Table II-9
Cumulative Impacts of EE on Load Forecast by Customer Type

Planning Year	Residential Allocation (GWh)	Watt-Hour Allocation (GWh)	0-100 kW Allocation (GWh)
2010	302.1	3.1	42.2
2011	521.9	5.9	72.5
2012	806.7	9.5	116.8
2013	1,128.9	13.5	167.1
2014	1,452.2	17.6	217.4

[9] The PUA does not prescribe how the kWh targets are to be apportioned among the customer classes, and the energy efficiency plan did not set goals on a customer class basis.

C. Impact of Renewable Energy Resources

Section 1-75(c) of the IPA Act (20 ILCS 3855/1-75(c)) establishes the following goals and cost thresholds for cost effective renewable energy resources:

Table II-10

Renewable Energy Resource Requirements

Delivery Period	Minimum Percentage	Maximum Cost
2010-2011	5% of June 1, 2008 through May 31, 2009 Eligible Retail Customer load	The greater of an additional 0.5% of the amount paid per kilowatthour by those customers during the year ending May 31, 2009 or 1.5% of the amount paid per kilowatthour by those customers during the year ending May 31, 2007.
2011-2012	6% of June 1, 2009 through May 31, 2010 Eligible Retail Customer load	The greater of an additional 0.5% of the amount paid per kilowatt hour by those customers during the year ending May 31, 2010 or 2% of the amount paid per kilowatt hour by those customers during the year ending May 31, 2007.
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, 2012 through May 31, 2013 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.

Based on the above, Table II-11 shows the amount of renewable energy resources that need to be procured over the upcoming procurement period and the maximum amount that may be spent acquiring such resources:

Table II-11

Delivery Period	Targeted REC Purchases (MWh)	REC Budget ($M)	Maximum ACP Rate ($/MWh)
2010-2011	1,887,014	58.2	1.598

Since renewable energy resources do not affect demand or consumption, these targets will have no impact on the Forecast.

SB2150, discussed above, also revised the renewable energy provisions of the IPA Act. If enacted into law, beginning June 1, 2010, ComEd must begin collecting from its Hourly Service customers certain Alternative Compliance Payments (“ACP”) that are described in that bill. Beginning in 2011, ComEd must include in its Forecast the amounts collected in the prior year ending May 31. The IPA is then to increase it’s spending for renewable energy resources for the next plan by the amount collected. These changes will also have no impact on this Forecast.

3. Five-Year Monthly Load Forecast

Based on all of the factors discussed in this section, ComEd has developed the following forecast of projected energy sales to Eligible Retail Customers for the period from June 1, 2010 through May 31, 2011:

Table II-12

ComEd Procurement Period Load Forecast (Expected Load)
Projected Energy Sales and Average Demand For Eligible Retail Customers
(Weather Normal, Line Loss and DSM Adjusted)

Year	Month	Total Load (MWh)		Average Load (MW)	
		On-Peak	Off-Peak	On-Peak	Off-Peak
2010	6	1,896,921	1,624,045	5,389	4,413
2010	7	2,231,242	2,197,192	6,641	5,385
2010	8	2,169,255	1,969,226	6,163	5,024
2010	9	1,588,361	1,512,634	4,727	3,939
2010	10	1,357,368	1,415,482	4,040	3,469
2010	11	1,501,640	1,500,691	4,469	3,908
2010	12	1,916,427	1,695,654	5,208	4,510
2011	1	1,752,398	1,886,938	5,215	4,625
2011	2	1,557,990	1,522,786	4,869	4,326
2011	3	1,599,912	1,451,093	4,348	3,859
2011	4	1,301,326	1,311,732	3,873	3,416
2011	5	1,330,118	1,399,860	3,959	3,431
Totals		**20,202,958**	**19,487,333**		

The forecast set forth above shows ComEd's expected load for the 2010 planning year. The PUA requires that the forecast cover a 5- year planning period. The forecast for ComEd's expected load for the 5-year planning period is set forth in Appendix B-1. The PUA also requires ComEd to provide low-load and high-load scenarios. That information for the 2010 planning year is set forth in Tables II-13 and II-14. The low-load and high-load scenarios for the 5-year planning period are set forth in Appendix B -2 and Appendix B-3, respectively. In all of the forecasted sales tables, "line loss" refers only to distribution losses.

Table II-13

ComEd Procurement Period Load Forecast (Low Load)
Projected Energy Sales and Average Demand For Eligible Retail Customers
(Line Loss and DSM Adjusted)

Year	Month	Total Load (MWh)		Average Load (MW)	
		On-Peak	Off-Peak	On-Peak	Off-Peak
2010	6	1,584,668	1,555,100	4,502	4,226
2010	7	1,904,731	1,810,785	5,669	4,438
2010	8	1,728,828	1,641,785	4,911	4,188
2010	9	1,466,876	1,452,475	4,366	3,782
2010	10	1,292,208	1,201,703	3,846	2,945
2010	11	1,298,615	1,370,985	3,865	3,570
2010	12	1,650,192	1,649,663	4,484	4,387
2011	1	1,634,563	1,662,034	4,865	4,074
2011	2	1,378,166	1,372,652	4,307	3,900
2011	3	1,305,459	1,314,545	3,547	3,496
2011	4	1,178,497	1,135,714	3,507	2,958
2011	5	1,191,060	1,246,253	3,545	3,055
Totals		**17,613,863**	**17,413,694**		

Table II-14

ComEd Procurement Period Load Forecast (High Load)
Projected Energy Sales and Average Demand For Eligible Retail Customers
(Line Loss and DSM Adjusted)

Year	Month	Total Load (MWh)		Average Load (MW)	
		On-Peak	Off-Peak	On-Peak	Off-Peak
2010	6	2,243,061	1,868,006	6,372	5,076
2010	7	2,740,784	2,536,267	8,157	6,216
2010	8	3,042,075	2,598,387	8,642	6,629
2010	9	1,705,314	1,619,059	5,075	4,216
2010	10	1,495,123	1,520,640	4,450	3,727
2010	11	1,753,289	1,751,082	5,218	4,560
2010	12	2,131,819	1,890,020	5,793	5,027
2011	1	1,914,830	2,059,273	5,699	5,047
2011	2	1,765,411	1,762,320	5,517	5,007
2011	3	1,836,725	1,579,487	4,991	4,201
2011	4	1,536,739	1,524,171	4,574	3,969
2011	5	1,483,888	1,518,612	4,416	3,722
Totals		**23,649,058**	**22,227,324**		

The low-load and the high-load scenarios are based upon a change to three of the main variables impacting load: weather, switching and load growth.[10]

The low-load scenario assumes that the summer weather is cooler than normal, that load growth occurs at a rate 2% less than is expected as shown in the load growth forecast in Table II-12, and that Hourly service and RES sales increase relative to the expected forecast shown in Table II-12. In this scenario an additional 25,000 residential customers are assumed to opt for RRTP in January 2011. Plus, residential RES sales increase over time related to favorable market conditions for the RES. For example, January 2014 RES sales reach 6% of total single -family sales in this scenario. Likewise, similar dynamics occur for the 0 to 100 kW customer group. June 2011 Blended sales are 54% of total 0 to 100 kW sales in the Forecast, but only 34% in this scenario.

The high-load scenario assumes that the summer weather is much hotter than normal (the scenario uses data from 1995, which is the warmest summer in the last 30 years), that load growth occurs at a rate 2% more than is expected, and that switching decreases. The low switching scenario reflects a reduction of 25,000 RRTP customers as either the Smart Grid Investment Grant Program is not approved or else it is decided to switch these customers to a different type of tariff and no residential switching therefore occurs. Also, the expected movement of the 0 to 100 kW customers to RES service not only does not occur, but some opt for Blended service. June 2011 RES sales are 45% of total 0 to100 kW customer class sales in the Forecast, but only 20% in this scenario.

The +/- 2% load growth assumption in both scenarios reflects, in part, the economic uncertainty that currently exists. “Despite indications that the worst of the financial crisis and economic downturn is over, conditions remain extraordinary fragile” (Mark Zandi of Moody’s Economy.com) [11]. ComEd’s intention is too keep the IPA informed of significant changes in its forecast during the proceedings.

III. CONCLUSION

For all of the reasons described here, ComEd believes that its Forecast for the period June 1, 2010 through May 31, 2015 is consistent with the requirements of the PUA and provides an appropriate approach to develop the procurement plan to acquire supply for the applicable retail customers.

[10] In ComEd’s initial procurement plan, the low-load and high-load scenarios were not adjusted for weather. Instead, the impacts of weather on load were considered in the risk analysis section of the procurement plan. Because ComEd will not be developing the procurement plan and risk analysis for the upcoming procurement event, ComEd thought it appropriate to include the weather-related load impacts in these scenarios for purposes of this Forecast.

[11] Mark Zandi, “Expand the Housing Tax Credit” June 16, 2009 article from Moody’s Economy.com

Appendices

A. Load Forecast Models

1. Residential Single Family Model (Hour 16)
2. ComEd Model Coefficients
3. ComEd Model Regression Statistics
4. Detailed Description of Variables Used In Forecast Models

B. Five-Year Load Forecast

1. Expected load
2. Low Load
3. High Load

Appendix A-1

Residential Single Family Model (Hour 16)			
Variable	**Coefficient**	**T-Stat**	**Notes**
CONSTANT	1.772	13.387	Constant term
Monday Binary	-0.102	-7.175	
Tuesday Binary	-0.123	-8.728	
Wednesday Binary	-0.137	-9.772	
Thursday Binary	-0.150	-10.616	
Friday Binary	-0.131	-9.296	
Saturday Binary	-0.024	-2.073	
MLK Binary	0.028	0.499	Martin Luther King's Day
PresDay Binary	0.073	1.309	President's Day
GoodFri Binary	0.065	1.044	Good Friday
MemDay Binary	0.170	2.698	Memorial Day
July4th Binary	0.012	0.188	July 4th.
LaborDay Binary	0.284	4.515	Labor Day
Thanks Binary	0.110	1.715	Thanksgiving Day
FriAThanks Binary	0.034	0.550	Friday after Thanksgiving Day
XMasWkB4 Binary	0.146	2.166	Week before Christmas
XMasEve Binary	0.357	4.137	Christmas Eve
XMasDay Binary	0.230	2.840	Christmas Day
XMasWk Binary	0.137	1.962	Christmas Week
NYEve Binary	0.112	1.195	New Year's Eve Day
NYDay Binary	0.179	2.644	New Year's Day
XMasLights Binary	-0.0003	-0.186	Christmas Lights
DLSav Binary	-0.406	-3.888	Day-Light Sayings
Sun.FracDark6	0.393	4.995	Fraction of hour 6 am that is dark
Sun.FracDark7	0.185	3.124	Fraction of hour 7 am that is dark
Sun.FracDark8	0.280	3.214	Fraction of hour ending 8 am that is dark
Sun.FracDark17	0.107	1.690	Fraction of hour ending 5 pm that is dark
Sun.FracDark18	-0.130	-1.881	Fraction of hour ending 6 pm that is dark
Sun.FracDark19	-0.195	-3.118	Fraction of hour ending 7 pm that is dark
Sun.FracDark20	-0.238	-3.615	Fraction of hour ending 8 pm that is dark
Sun.FracDark21	-0.636	-6.011	Fraction of hour ending 9 pm that is dark
Binary Feb	-0.035	-0.694	
Binary Mar	0.029	0.531	
Binary Apr	-0.023	-0.382	
Binary May	0.038	0.559	
Binary Jun	0.158	2.173	
Binary Jul	0.275	3.889	
Binary Aug	0.231	3.718	
Binary Sep	0.220	3.747	

Binary Oct	0.166	2.680	
Binary Nov	0.062	1.154	
Binary Dec	0.112	2.283	
Usage Trend	-0.025	-5.118	
Fall HDD Spline	0.004	1.773	HDD Spline for September and October
November HDD Spline	0.005	3.235	HDD Spline for November
December HDD Spline	0.004	3.585	HDD Spline for December
January HDD Spline	0.006	6.324	HDD Spline for January
February HDD Spline	0.008	6.751	HDD Spline for February
March HDD Spline	0.005	3.967	HDD Spline for March
Spring HDD Spline	0.008	4.816	HDD Spline for April and May
Day lag of HDD Spline	-0.001	-0.731	
Two day lag of HDD Spline	0.0002	0.247	
Weekend HDD Spline	0.001	1.100	
Trend HDD Spline	0.001	4.610	
April THI Spline	0.034	1.146	THI (Temperature Humidity Index) Spline for April
May THI Spline	0.140	20.840	THI (Temperature Humidity Index) Spline for May
June THI Spline	0.155	41.771	THI (Temperature Humidity Index) Spline for June
July THI Spline	0.144	37.844	THI (Temperature Humidity Index) Spline for July
August THI Spline	0.160	40.502	THI (Temperature Humidity Index) Spline for August
September THI Spline	0.184	34.926	THI (Temperature Humidity Index) Spline for September
October THI Spline	0.167	20.103	THI (Temperature Humidity Index) Spline for October
Day lag of THI Spline	0.014	4.809	
Two day lag of THI Spline	0.010	4.419	
Weekend THI Spline	0.009	3.213	
THI Spline for Trend	-0.0003	-0.238	
2007 Plus Dummy	0.074	5.714	An End Shift to describe usage for 2007 and beyond

The coefficients provide the effect that each variable has on the hourly usage for a single hour (Hour 16 which includes the load from 3 p.m. to 4 p.m. in the afternoon). The “T-Stat” provides the statistical significance of the variable, with a value generally greater than +/- two (2) indicating that the coefficient is significantly different from zero.

The hourly model for Hour 16 has an adjusted R-squared of 0.93, which means that 93% of the variance in the hourly data is being explained by the model. At the daily level, the mean average percent error (“MAPE”) for the model is 4.0%. The 4.0% daily MAPE means that the average percentage difference on a daily basis between the usage predicted by the model and the actual usage for that period was very small. In other words, the model can explain usage with almost a 96% accuracy rate. Such a high accuracy rate is particularly noteworthy because the model is dealing with very short time frames in which many factors may come into play. The high accuracy rate, the low MAPE and the high R-squared indicate that the model captures the vast majority of factors that affect electrical usage.

Appendix A-2

ComEd Model Coefficients

ComEd Zone Model

Variable	Coefficient	StdErr	T-Stat
CONST	1223.349	362.42	3.375
Monthly.GMPDays	7.028	0.724	9.7
Monthly.ResCustDays	1.09	0.167	6.519
CalVars.Jan	-94.384	26.605	-3.548
CalVars.Feb	-240.624	40.01	-6.014
CalVars.Mar	-283.422	31.23	-9.075
CalVars.Apr	-458.748	43.879	-10.46
CalVars.May	-406.946	55.998	-7.267
CalVars.Jun	-265.145	57.203	-4.635
CalVars.Jul	-202.842	67.557	-3.003
CalVars.Aug	-16.883	63.708	-0.265
CalVars.Sep	-127.562	51.94	-2.456
CalVars.Oct	-199.841	49.587	-4.03
CalVars.Nov	-179.604	37.283	-4.817
CalVars.Yr05Plus	152.941	18.81	8.131
CalVars.Apr08Plus	-87.628	21.756	-4.028
CalHDD.HDDSpline	1.895	0.076	24.841
CalHDD.HDDSplineTrend	0.036	0.006	5.656
CalCDD.SpringTDD	12.338	0.982	12.559
CalCDD.SummerTDD	13.973	0.287	48.625
CalCDD.FallTDD	12.762	1.636	7.8
CalCDD.TDDTrend	0.526	0.046	11.325
CalCDD.TDDTrend2000Plus	-0.237	0.091	-2.601
CalCDD.Yr06Plus_TDDShift	-1.275	0.248	-5.142

Residential Customer Class Model

Variable	Coefficient	StdErr	T-Stat
Monthly.Jan	14.41	1.947	7.402
Monthly.Feb	12.833	1.895	6.774
Monthly.Mar	11.99	1.85	6.479
Monthly.Apr	11.087	1.801	6.156
Monthly.May	10.532	1.788	5.891
Monthly.Jun	11.062	1.892	5.845
Monthly.Jul	12.463	2.068	6.028
Monthly.Aug	12.002	2.085	5.757
Monthly.Sep	11.727	2.019	5.809
Monthly.Oct	11.162	1.813	6.156
Monthly.Nov	11.69	1.803	6.482
Monthly.Dec	13.345	1.885	7.08
Monthly.Yr2004Plus	0.628	0.153	4.096
Monthly.July07Plus	-0.349	0.204	-1.716
CycVars.IncPerHH	0.066	0.018	3.582
CycWthrT.ResHDD	0.195	0.013	15.567
CycWthrT.ResHDDTrend	0.003	0.001	3.105
CycWthrT.ResCDD_Spring	1.346	0.327	4.119
CycWthrT.ResCDD_Jun	2.119	0.143	14.833
CycWthrT.ResCDD_Jul	2.313	0.079	29.386
CycWthrT.ResCDD_Aug	2.507	0.061	41.029
CycWthrT.ResCDD_Sep	2.56	0.105	24.41
CycWthrT.ResCDD_Fall	2.572	0.17	15.099
CycWthrT.ResCDDTrend	0.073	0.006	12.266
CycWthrT.Yr06Plus_ResCDDShift	-0.334	0.054	-6.154
XVars.NewMonthlyBill	-0.028	0.014	-1.986
AR(1)	0.43	0.085	5.074

Small C&I Customer Class Model

Variable	Coefficient	StdErr	T-Stat
Monthly.Jan	-34.674	7.477	-4.637
Monthly.Feb	-31.392	7.489	-4.192
Monthly.Mar	-32.018	7.429	-4.31
Monthly.Apr	-33.508	7.392	-4.533
Monthly.May	-34.032	7.363	-4.622
Monthly.Jun	-34.41	7.35	-4.682
Monthly.Jul	-34.031	7.355	-4.627
Monthly.Aug	-31.317	7.357	-4.257
Monthly.Sep	-31.509	7.347	-4.289
Monthly.Oct	-30.953	7.353	-4.209
Monthly.Nov	-32.827	7.384	-4.446
Monthly.Dec	-34.646	7.445	-4.653
CycVars.ResCust	0.029	0.003	8.214
Monthly.July06Plus	-1.908	0.569	-3.356
CycWthrT.SCI_HDD	0.424	0.042	10.126
CycWthrT.SCI_HDDTrend	0.008	0.003	2.203
CycWthrT.SCI_CDD	1.967	0.115	17.048
CycWthrT.SCI_CDDTrend	0.041	0.009	4.682
XVars.Emp_NonManuf	0.005	0.002	2.144
AR(1)	0.475	0.071	6.648

StreetLighting Class Model

Variable	Coefficient	StdErr	T-Stat
Monthly.Jan	-5.84	0.622	-9.387
Monthly.Feb	-5.847	0.623	-9.391
Monthly.Mar	-6.059	0.622	-9.74
Monthly.Apr	-6.163	0.624	-9.878
Monthly.May	-6.302	0.623	-10.11
Monthly.Jun	-6.32	0.623	-10.14
Monthly.Jul	-6.292	0.623	-10.11
Monthly.Aug	-6.236	0.622	-10.02
Monthly.Sep	-6.115	0.623	-9.818
Monthly.Oct	-6.029	0.623	-9.672
Monthly.Nov	-5.933	0.624	-9.502
Monthly.Dec	-5.836	0.623	-9.365
Monthly.Yr2007Plus	-0.076	0.03	-2.513
CycVars.ResCust	0.002	0	12.534

Appendix A-3

ComEd Model Regression Statistics

Regression Statistics	ZONE	Residential	Small C&I	StreetLighting
Iterations	1	17	14	1
Adjusted Observations	169	153	150	91
Deg. of Freedom for Error	145	126	130	77
R-Squared	0.994	0.994	0.981	0.911
Adjusted R-Squared	0.993	0.993	0.979	0.897
Durbin-Watson Statistic	1.127	1.964	2.195	1.163
AIC	8.924	-1.91	0.368	-4.996
BIC	9.369	-1.375	0.769	-4.609
F-Statistic	1063.495	811.409	341.433	56.635
Prob (F-Statistic)	0	0	0	0
Log-Likelihood	-964.16	-43.71	-220.43	110.95
Model Sum of Squares	1.61E+08	2768	8719	5
Sum of Squared Errors	955601	16	166	0
Mean Squared Error	6590.35	0.13	1.28	0.01
Std. Error of Regression	81.18	0.36	1.13	0.08
Mean Abs. Dev. (MAD)	58.95	0.26	0.81	0.05
Mean Abs. % Err. (MAPE)	0.75%	1.21%	0.95%	2.82%
Ljung-Box Statistic	106.38	30.96	20.65	29.57
Prob (Ljung-Box)	0	0.1548	0.6593	0.1994

Appendix A-4
Detailed Description Of Variables
Used In Forecast Models

The econometric models are statistical multi-variant regressions that determine the correlation between electrical usage (dependent variable) and weather, economic and monthly factors (independent variables). Consistent with its recent delivery services rate case filing, ComEd's weather normals are based on the 30-year time period of 1977 to 2006. The following models are used in producing the energy sales forecast (GWh) for the eligible customers:

Monthly Zone energy usage for the ComEd zone
Monthly Residential bill-cycle energy usage
Monthly Small C&I bill-cycle energy usage
Monthly Street Lighting bill-cycle energy usage

ComEd's Load Forecasting group with the input of industry experts developed the models. The following sections describe each model and its specifications. Appendices A-2 and A-3 contain the coefficients and other regression statistics for the models.

ComEd's Monthly Zone Model

The dependent variable in the zone model is monthly zone energy usage for the ComEd service territory. The monthly zone usage is in GWh units. The performance of the model is shown in the Chart II-10 in Section II B 1 d (ii) (estimated[12] vs. actual) for the January 2000 to February 2009 time period.

The independent variables within the model are:

- The monthly binary variables reflect monthly usage patterns. Customer electrical usage is a function of other items besides cooling and heating (e.g., lighting). This other usage is not constant per month and the monthly binary variables are used to account for this variability. December is excluded from the monthly binaries, as the constant term establishes December as the base from which the monthly binary variables are adjusted.

- The GMP variable is the gross metropolitan product for the Chicago metropolitan area and also includes Rockford. This variable measures economic activity for the ComEd service territory. The GMP is adjusted for inflation and is obtained from Moody's Economy.com. Further, the variable is adjusted for the number of weekends (and holidays) and weekdays within a calendar month because overall

[12] As noted in the body of the Forecast, the estimated data used in Charts II-10, II-11 and II-12 is based on actual weather

energy usage for a given month is a function of those daily influences. The variable's units are billions of dollars.

- The Residential Customers variable is the total number of residential customers within the ComEd service territory. This economic variable reflects the effect of a growing customer base on energy sales and is driven by household formations. This variable is also adjusted for the number of weekends, holidays and weekdays within a calendar month.

- The temperature and humidity degree day ("TDD") variables are weather variables designed to capture the effect on usage from cooling equipment. The TDD variable is similar in design to a cooling degree day ("CDD") variable. A CDD weather variable is often used in energy models. The standard CDD measures the difference in the average daily temperature above a specific threshold (typically 65 degrees as that is a common point at which cooling activity begins). The TDD variable provides several enhancements to the typical CDD variable as delineated below:

  The average daily temperature is the 24-hour average instead of the average of the maximum and minimum temperatures for the day. This captures frontal movements within the day.

  Humidity is included in the TDD variable as humidity does influence electrical usage.

  The TDD variable uses multiple degree bases instead of just a 65 degree-base. This captures the change in the rate at which customers use electricity at different temperature levels.

  The TDD variable is interacted with seasonal binary variables (i.e., Spring, Summer and Fall) to reflect the seasonal usage pattern related to cooling equipment.

  The TDD variable is in degree-day units.

  The TDD trend variable is a weather variable that captures the changing relationship of cooling equipment over time. Simply put, the effect of a TDD changes over time as customers' usage patterns change over time. For example, as homes have become larger over time the amount of cooling load associated with a change in temperature will also change.

  The TDD trend variable essentially captures the growing influence of cooling equipment over time within the service territory. The TDD trend variable is designed to capture this changing relationship by interacting the TDD variable with a linear time series variable. The TDD trend variable is in degree-day units.

The TDD shift variable is a weather variable akin to the TDD trend variable. This variable is interacted with a binary variable for all years greater than or equal to 2006. The negative sign in the variable's coefficient acknowledges the reduction in long term cooling effect over the past couple of years.

- The HDD Spline variable is a weather variable that measures the relationship on electrical usage from space heating equipment (e.g., natural gas furnace fans and electrical space-heating equipment). The HDD Spline variable is similar in concept to the industry-standard heating degree day ("HDD") weather variable. The HDD Spline provides a couple of enhancements to the HDD weather variable:

  The average daily temperature is the 24-hour average instead of the average of the maximum and minimum temperatures for the day. This captures frontal movements within the day.

  The HDD Spline uses multiple degree bases instead of just a 65 degree-base. This captures the change in the rate at which customers use electricity at different temperature levels.

  The HDD Spline variable is in degree-day units.

  The HDD Spline trend variable is a weather variable that reflects the changing relationship of heating equipment over time. This variable is conceptually similar to the TDD trend variable. The HDD spline variable is in degree-day units.

- The Year 2005 and April 2008 Shift Plus variables are binary variables designed to capture very recent usage activity within the model. For example, the 2005 Shift Plus variable is a binary variable with the unit one for all months beginning with January 2005 and thereafter. By forcing all of the residuals to sum to zero for the months January 2005 to present, the variable is causing the model to be closely aligned with recent usage activity. This variable is useful for forecasting purposes as it ensures that the forecasted usage is also closely aligned with the most recent pattern of electrical usage.

The coefficient values and the standard measurements of significance within the model (e.g., t-stats) and the overall model performance (e.g., R-squared and MAPE) are contained in Appendices A- 2 and A-3. Chart II-10 contains a plot of the model's estimated monthly usage vs. actual monthly usage from January 2000 to February 2009. The two curves are tightly aligned, which speaks to the accuracy of the model.

ComEd Residential Model

The dependent variable is residential use per customer per day and the units are kWh per customer per day. Chart II-2 shows the model's forecast performance (estimated vs. actual monthly sales from January 2006 to February 2009), which reflects a close fit.

The independent variables are noted below. (Because many of the variables follow the same purpose and logic as in the Monthly Zone model, please see the Monthly Zone model description for additional information.)

- The monthly binary variables reflect monthly usage patterns.
- The Real Income per Household variable is the disposable personal income for the Chicago metropolitan area and Rockford (adjusted for inflation) divided by the number of households for the same area. The data is obtained from Moody's Economy.com. This variable captures the rising household incomes within ComEd's service territory and the correlation it has with consumer purchases of electronic equipment and housing stock. The variable is in dollars per household units.
- The Monthly Bill variable is a typical monthly residential electricity bill assuming historical tariff charges and weather normal customer usage for the year 2002 (adjusted for inflation). Specifically, the historical tariff charges for a single-family and multi-family (both non-space heat) were multiplied by the weather adjusted billing units from the year 2002 for both residential groups. The monthly bills for both residential groups were weighted, based on energy sales, to form a single monthly bill. The monthly bill was also adjusted for the Chicago CPI-U. This variable reflects the influence of electricity charges/prices over time related to consumer behavior.
- Weather variables used in the residential model are similar in concept to the weather variables described in the Monthly Zone model section and will not be repeated here.
- The Year 2004 Plus and July 2007 Plus binary variables are similar in concept to the same variables used in the Monthly Zone model.

ComEd Small C&I Model

The dependent variable is Small C&I use per day and the units are GWh per day. The independent variables within the model are:

- The monthly binary variables, weather variables and shift variables are similar in concept to the Monthly Zone model and will not be repeated here.
- The residential customers variable is the total number of residential customers within the ComEd service territory. This economic variable reflects the influence

of a growing service territory (i.e., residential customers) on Small C&I energy usage. The units are in thousands of customers.

- The Employment variable is an economic variable that measures the total non-manufacturing employment in the Chicago area. Job growth is correlated to Small C&I development and growth.

- The July 2006 Shift Plus binary variable is similar in concept to the Monthly Zone model.

ComEd Street Light Model

The dependent variable is Street Lighting use per day and the units are GWh per day. The independent variables are:

- Monthly binary variables and a shift variable that are similar in concept to the Monthly Zone model.

- The residential customers variable is the total number of residential customers within the ComEd service territory. This economic variable reflects the relationship of a growing service territory (measured by the number of residential customers) and street lighting sales.

Appendix B-1

ComEd Procurement Period Load Forecast (Expected Load) Projected Energy Sales and Average Demand For Eligible Retail Customers (Weather Normal, Line Loss and DSM Adjusted)					
Year	Month	Total Load (MWh)		Average Load (MW)	
		On-Peak	Off-Peak	On-Peak	Off-Peak
2010	6	1,896,921	1,624,045	5,389	4,413
2010	7	2,231,242	2,197,192	6,641	5,385
2010	8	2,169,255	1,969,226	6,163	5,024
2010	9	1,588,361	1,512,634	4,727	3,939
2010	10	1,357,368	1,415,482	4,040	3,469
2010	11	1,501,640	1,500,691	4,469	3,908
2010	12	1,916,427	1,695,654	5,208	4,510
2011	1	1,752,398	1,886,938	5,215	4,625
2011	2	1,557,990	1,522,786	4,869	4,326
2011	3	1,599,912	1,451,093	4,348	3,859
2011	4	1,301,326	1,311,732	3,873	3,416
2011	5	1,330,118	1,399,860	3,959	3,431
2011	6	1,852,504	1,584,141	5,263	4,305
2011	7	2,076,846	2,250,683	6,490	5,308
2011	8	2,228,803	1,841,624	6,057	4,898
2011	9	1,539,978	1,492,317	4,583	3,886
2011	10	1,330,406	1,395,685	3,960	3,421
2011	11	1,481,279	1,485,288	4,409	3,868
2011	12	1,730,767	1,854,559	5,151	4,545
2012	1	1,748,566	1,900,359	5,204	4,658
2012	2	1,619,830	1,557,231	4,821	4,326
2012	3	1,524,153	1,524,709	4,330	3,890
2012	4	1,308,312	1,317,586	3,894	3,431
2012	5	1,411,591	1,355,879	4,010	3,459
2012	6	1,790,295	1,684,767	5,328	4,387
2012	7	2,217,563	2,192,986	6,600	5,375
2012	8	2,249,829	1,876,983	6,114	4,992
2012	9	1,403,283	1,636,107	4,616	3,933
2012	10	1,480,948	1,297,937	4,024	3,452
2012	11	1,502,099	1,494,665	4,471	3,892
2012	12	1,659,087	1,950,473	5,185	4,600
2013	1	1,848,540	1,846,176	5,252	4,710
2013	2	1,555,071	1,548,806	4,860	4,400
2013	3	1,460,509	1,597,436	4,347	3,915
2013	4	1,381,178	1,270,897	3,924	3,454
2013	5	1,419,397	1,366,098	4,032	3,485

ComEd Procurement Period Load Forecast (Expected Load)
Projected Energy Sales and Average Demand For Eligible Retail Customers
(Weather Normal, Line Loss and DSM Adjusted)

Year	Month	Total Load (MWh)		Average Load (MW)	
		On-Peak	Off-Peak	On-Peak	Off-Peak
2013	6	1,706,777	1,780,963	5,334	4,452
2013	7	2,344,057	2,116,293	6,659	5,399
2013	8	2,160,492	1,973,720	6,138	5,035
2013	9	1,487,679	1,568,268	4,649	3,921
2013	10	1,481,418	1,303,568	4,026	3,467
2013	11	1,421,649	1,567,975	4,443	3,920
2013	12	1,745,838	1,887,380	5,196	4,626
2014	1	1,851,420	1,858,493	5,260	4,741
2014	2	1,553,024	1,557,109	4,853	4,424
2014	3	1,456,804	1,606,089	4,336	3,936
2014	4	1,376,102	1,276,207	3,909	3,468
2014	5	1,346,504	1,432,213	4,007	3,510
2014	6	1,799,438	1,717,355	5,355	4,472
2014	7	2,360,789	2,126,231	6,707	5,424
2014	8	2,065,741	2,068,209	6,148	5,069
2014	9	1,568,870	1,496,449	4,669	3,897
2014	10	1,477,930	1,306,305	4,016	3,474
2014	11	1,344,177	1,635,166	4,422	3,931
2014	12	1,834,257	1,824,824	5,211	4,655
2015	1	1,770,149	1,946,892	5,268	4,772
2015	2	1,562,628	1,562,068	4,883	4,438
2015	3	1,536,587	1,553,189	4,365	3,962
2015	4	1,374,992	1,286,587	3,906	3,496
2015	5	1,278,514	1,501,852	3,995	3,542
Totals		**99,929,628**	**98,764,130**		

Appendix B-2

ComEd Procurement Period Load Forecast (Low Load) Projected Energy Sales and Average Demand For Eligible Retail Customers (Line Loss and DSM Adjusted)					
Year	Month	Total Load (MWh)		Average Load (MW)	
		On-Peak	Off-Peak	On-Peak	Off-Peak
2010	6	1,584,668	1,555,100	4,502	4,226
2010	7	1,904,731	1,810,785	5,669	4,438
2010	8	1,728,828	1,641,785	4,911	4,188
2010	9	1,466,876	1,452,475	4,366	3,782
2010	10	1,292,208	1,201,703	3,846	2,945
2010	11	1,298,615	1,370,985	3,865	3,570
2010	12	1,650,192	1,649,663	4,484	4,387
2011	1	1,634,563	1,662,034	4,865	4,074
2011	2	1,378,166	1,372,652	4,307	3,900
2011	3	1,305,459	1,314,545	3,547	3,496
2011	4	1,178,497	1,135,714	3,507	2,958
2011	5	1,191,060	1,246,253	3,545	3,055
2011	6	1,492,593	1,361,566	4,240	3,700
2011	7	1,813,202	1,600,517	5,666	3,775
2011	8	1,600,160	1,529,717	4,348	4,068
2011	9	1,377,006	1,308,935	4,098	3,409
2011	10	1,188,727	1,109,657	3,538	2,720
2011	11	1,162,567	1,328,861	3,460	3,461
2011	12	1,525,367	1,571,504	4,540	3,852
2012	1	1,509,673	1,632,731	4,493	4,002
2012	2	1,324,249	1,364,761	3,941	3,791
2012	3	1,274,306	1,202,563	3,620	3,068
2012	4	1,121,986	1,072,554	3,339	2,793
2012	5	1,136,425	1,207,014	3,228	3,079
2012	6	1,506,496	1,293,310	4,484	3,368
2012	7	1,707,892	1,653,662	5,083	4,053
2012	8	1,650,858	1,400,077	4,486	3,724
2012	9	1,276,582	1,314,934	4,199	3,161
2012	10	1,143,467	1,128,561	3,107	3,001
2012	11	1,205,340	1,215,337	3,587	3,165
2012	12	1,498,438	1,503,958	4,683	3,547
2013	1	1,511,337	1,608,516	4,294	4,103
2013	2	1,277,561	1,274,191	3,992	3,620
2013	3	1,220,346	1,194,726	3,632	2,928
2013	4	1,090,335	1,070,676	3,098	2,909
2013	5	1,153,362	1,142,270	3,277	2,914

ComEd Procurement Period Load Forecast (Low Load)
Projected Energy Sales and Average Demand For Eligible Retail Customers
(Line Loss and DSM Adjusted)

Year	Month	Total Load (MWh)		Average Load (MW)	
		On-Peak	Off-Peak	On-Peak	Off-Peak
2013	6	1,449,805	1,276,526	4,531	3,191
2013	7	1,656,206	1,650,445	4,705	4,210
2013	8	1,615,558	1,345,411	4,590	3,432
2013	9	1,262,526	1,265,637	3,945	3,164
2013	10	1,105,313	1,103,305	3,004	2,934
2013	11	1,146,890	1,190,707	3,584	2,977
2013	12	1,400,841	1,536,353	4,169	3,766
2014	1	1,477,702	1,556,998	4,198	3,972
2014	2	1,224,975	1,248,087	3,828	3,546
2014	3	1,167,132	1,164,512	3,474	2,854
2014	4	1,024,635	1,071,034	2,911	2,910
2014	5	1,090,035	1,125,262	3,244	2,758
2014	6	1,382,246	1,257,780	4,114	3,275
2014	7	1,555,932	1,661,665	4,420	4,239
2014	8	1,516,179	1,350,945	4,512	3,311
2014	9	1,213,527	1,245,301	3,612	3,243
2014	10	1,103,698	1,025,208	2,999	2,727
2014	11	1,079,263	1,163,694	3,550	2,797
2014	12	1,352,429	1,522,261	3,842	3,883
2015	1	1,434,828	1,489,951	4,270	3,652
2015	2	1,203,316	1,218,107	3,760	3,461
2015	3	1,131,087	1,150,456	3,213	2,935
2015	4	1,017,982	1,019,480	2,892	2,770
2015	5	1,059,403	1,087,997	3,311	2,566
Totals		**81,053,646**	**80,231,414**		

Appendix B-3

ComEd Procurement Period Load Forecast (High Load) Projected Energy Sales and Average Demand For Eligible Retail Customers (Line Loss and DSM Adjusted)					
Year	Month	Total Load (MWh)		Load (MW)	
		On-Peak	Off-Peak	On-Peak	Off-Peak
2010	6	2,243,061	1,868,006	6,372	5,076
2010	7	2,740,784	2,536,267	8,157	6,216
2010	8	3,042,075	2,598,387	8,642	6,629
2010	9	1,705,314	1,619,059	5,075	4,216
2010	10	1,495,123	1,520,640	4,450	3,727
2010	11	1,753,289	1,751,082	5,218	4,560
2010	12	2,131,819	1,890,020	5,793	5,027
2011	1	1,914,830	2,059,273	5,699	5,047
2011	2	1,765,411	1,762,320	5,517	5,007
2011	3	1,836,725	1,579,487	4,991	4,201
2011	4	1,536,739	1,524,171	4,574	3,969
2011	5	1,483,888	1,518,612	4,416	3,722
2011	6	2,374,774	1,947,758	6,747	5,293
2011	7	2,751,053	2,764,465	8,597	6,520
2011	8	3,282,281	2,640,419	8,919	7,022
2011	9	1,799,559	1,683,414	5,356	4,384
2011	10	1,557,711	1,601,784	4,636	3,926
2011	11	1,841,899	1,831,063	5,482	4,768
2011	12	2,034,007	2,156,317	6,054	5,285
2012	1	1,994,045	2,159,298	5,935	5,292
2012	2	1,927,623	1,861,103	5,737	5,170
2012	3	1,776,857	1,758,935	5,048	4,487
2012	4	1,593,692	1,579,951	4,743	4,114
2012	5	1,621,335	1,499,462	4,606	3,825
2012	6	2,366,160	2,091,889	7,042	5,448
2012	7	2,946,358	2,786,617	8,769	6,830
2012	8	3,381,944	2,749,375	9,190	7,312
2012	9	1,655,678	1,904,457	5,446	4,578
2012	10	1,758,020	1,526,702	4,777	4,060
2012	11	1,893,831	1,896,808	5,636	4,940
2012	12	1,989,919	2,314,760	6,218	5,459
2013	1	2,169,994	2,122,222	6,165	5,414
2013	2	1,934,539	1,841,183	6,045	5,231
2013	3	1,712,260	1,906,957	5,096	4,674
2013	4	1,724,289	1,552,090	4,899	4,218
2013	5	1,657,633	1,549,732	4,709	3,953

ComEd Procurement Period Load Forecast (High Load) Projected Energy Sales and Average Demand For Eligible Retail Customers (Line Loss and DSM Adjusted)					
Year	Month	Total Load (MWh)		Load (MW)	
		On-Peak	Off-Peak	On-Peak	Off-Peak
2013	6	2,308,475	2,263,780	7,214	5,659
2013	7	3,136,294	2,786,984	8,910	7,110
2013	8	3,377,491	2,901,940	9,595	7,403
2013	9	1,827,021	1,829,315	5,709	4,573
2013	10	1,812,624	1,548,872	4,926	4,119
2013	11	1,843,843	2,026,876	5,762	5,067
2013	12	2,142,711	2,284,628	6,377	5,600
2014	1	2,207,278	2,185,376	6,271	5,575
2014	2	1,963,391	1,896,826	6,136	5,389
2014	3	1,740,995	1,954,850	5,182	4,791
2014	4	1,744,254	1,600,887	4,955	4,350
2014	5	1,586,709	1,675,701	4,722	4,107
2014	6	2,450,096	2,252,755	7,292	5,867
2014	7	3,244,753	2,832,204	9,218	7,225
2014	8	3,356,076	3,052,819	9,988	7,482
2014	9	1,924,632	1,816,979	5,728	4,732
2014	10	1,857,384	1,570,439	5,047	4,177
2014	11	1,784,778	2,157,854	5,871	5,187
2014	12	2,283,257	2,265,662	6,487	5,780
2015	1	2,154,300	2,330,210	6,412	5,711
2015	2	1,981,505	1,974,298	6,192	5,609
2015	3	1,900,646	1,898,264	5,400	4,843
2015	4	1,767,369	1,657,983	5,021	4,505
2015	5	1,531,013	1,794,661	4,784	4,233
Totals		**125,321,414**	**120,514,248**		

ATTACHMENT F: Commonwealth Edison Monthly Volume Projections per Rate Class for Five Year Planning Period, June 2011 through May 2016

Commonwealth Edison Monthly Volume Projections per Rate Class for Five Year Planning Period, June 2011 through May 2016

Contract Month	Projected Monthly Volume Requirements									
	SF MW	MF MW	SFSH MW	MFSH MW	WH MW	Small MW	Condo MW	DD MW	GL MW	Total MW
June-11	2,132	442	49	102	44	600	20	15	1	3,405
July-11	2,842	585	50	112	49	662	27	15	1	4,342
August-11	2,615	551	45	102	49	662	30	16	1	4,072
September-11	2,615	395	34	76	43	584	26	16	1	3,791
October-11	1,829	340	41	82	41	552	23	18	1	2,665
November-11	1,712	358	72	131	40	541	22	18	1	2,894
December-11	2,062	408	111	212	44	603	31	19	1	3,491
January-12	2,042	396	126	258	45	618	37	19	1	3,542
February-12	1,718	355	114	235	42	573	34	17	1	3,089
March-12	1,640	344	98	201	42	579	31	17	1	2,955
April-12	1,418	302	70	139	39	524	25	15	1	2,534
May-12	1,545	334	53	106	41	558	23	16	1	2,677
June-12	2,132	443	48	100	44	568	20	15	1	3,372
July-12	2,876	593	50	111	49	631	27	16	1	4,355
August-12	2,629	555	45	101	49	629	30	17	1	4,056
September-12	1,808	391	33	74	43	550	26	17	1	2,942
October-12	1,577	343	41	81	41	531	23	19	1	2,655
November-12	1,706	357	70	128	40	514	22	19	1	2,858
December-12	2,052	407	108	208	44	572	31	20	1	3,443
January-13	2,057	398	125	256	45	593	38	20	1	3,534
February-13	1,659	342	108	224	40	528	33	17	1	2,953
March-13	1,631	341	97	197	42	550	31	17	1	2,908
April-13	1,418	302	69	137	39	502	26	16	1	2,509
May-13	1,540	333	52	104	41	531	24	16	1	2,643
June-13	2,131	443	48	99	44	567	20	16	1	3,368
July-13	2,913	600	50	111	49	634	27	16	1	4,402
August-13	2,633	556	44	100	49	626	30	17	1	4,056
September-13	1,812	392	33	73	43	552	26	17	1	2,949
October-13	1,565	340	40	79	41	532	23	19	1	2,640
November-13	1,690	353	69	125	40	512	22	19	1	2,833
December-13	2,063	408	107	206	44	575	31	20	1	3,456
January-14	2,059	399	123	253	45	593	38	20	1	3,531
February-14	1,658	342	106	220	40	528	33	17	1	2,946
March-14	1,629	341	95	194	42	550	31	18	1	2,902
April-14	1,413	301	68	135	39	502	26	16	1	2,501
May-14	1,533	332	51	102	41	529	24	16	1	2,629

Contract Month	Projected Monthly Volume Requirements									
	SF MW	MF MW	SFSH MW	MFSH MW	WH MW	Small MW	Condo MW	DD MW	GL MW	Total MW
June-14	2,153	448	47	99	44	569	20	16	1	3,398
July-14	2,940	607	50	111	49	633	27	17	1	4,435
August-14	2,639	558	44	99	48	622	30	18	1	4,059
September-14	1,821	395	32	73	43	553	27	18	1	2,962
October-14	1,565	341	39	78	41	532	23	19	1	2,639
November-14	1,681	352	67	123	40	510	22	19	1	2,816
December-14	2,076	411	106	204	44	578	31	21	1	3,474
January-15	2,058	397	121	248	45	592	38	20	1	3,521
February-15	1,662	341	105	217	40	528	33	18	1	2,946
March-15	1,641	342	94	192	42	553	32	18	1	2,916
April-15	1,415	300	67	133	39	502	26	17	1	2,499
May-15	1,531	330	50	100	41	526	23	17	1	2,620
June-15	2,182	453	47	98	44	571	20	17	1	3,433
July-15	2,973	612	50	110	49	632	27	17	1	4,472
August-15	2,659	561	43	98	48	621	30	18	1	4,080
September-15	1,823	394	32	71	43	552	26	18	1	2,961
October-15	1,555	338	38	76	41	529	23	20	1	2,621
November-15	1,690	352	67	121	40	512	22	20	1	2,826
December-15	2,083	411	105	201	44	579	31	21	1	3,477
January-16	2,056	395	119	245	45	590	38	21	1	3,511
February-16	1,729	354	108	223	42	547	35	19	1	3,056
March-16	1,652	343	94	191	43	555	32	19	1	2,930
April-16	1,407	297	66	130	39	498	26	17	1	2,482
May-16	1,543	332	50	100	41	529	24	17	1	2,637

ATTACHMENT G: Commonwealth Edison System Supply Requirements Forecast for Five Year Planning Period, June 2011 through May 2016

Commonwealth Edison System Supply Requirements Forecast for Five Year Planning Period, June 2011 through May 2016

Contract Month	Total Load (MWh)		Average Load (MWh)	
	On-Peak	Off-Peak	On-Peak	Off-Peak
June-11	1,851,927	1,553,489	5,261	4,221
July-11	2,101,193	2,241,182	6,566	5,286
August-11	2,248,679	1,823,215	6,111	4,849
September-11	1,538,391	1,466,300	4,579	3,818
October-11	1,314,273	1,350,807	3,912	3,311
November-11	1,457,566	1,436,711	4,338	3,741
December-11	1,699,468	1,791,473	5,058	4,391
January-12	1,712,873	1,829,337	5,098	4,484
February-12	1,589,745	1,499,038	4,731	4,164
March-12	1,492,749	1,461,870	4,241	3,729
April-12	1,276,826	1,257,106	3,800	3,274
May-12	1,382,300	1,294,226	3,927	3,302
June-12	1,754,034	1,617,539	5,220	4,212
July-12	2,209,367	2,145,187	6,575	5,258
August-12	2,231,981	1,823,774	6,065	4,850
September-12	1,370,867	1,571,351	4,509	3,777
October-12	1,431,746	1,223,736	3,891	3,255
November-12	1,446,176	1,411,890	4,304	3,677
December-12	1,597,860	1,844,815	4,993	4,351
January-13	1,785,338	1,748,506	5,072	4,460
February-13	1,494,489	1,458,271	4,670	4,143
March-13	1,404,947	1,503,241	4,181	3,684
April-13	1,323,024	1,186,400	3,759	3,224
May-13	1,364,882	1,277,753	3,878	3,260
June-13	1,667,633	1,700,540	5,211	4,251
July-13	2,338,424	2,063,912	6,643	5,265
August-13	2,143,946	1,912,326	6,091	4,878
September-13	1,452,023	1,496,784	4,538	3,742
October-13	1,423,870	1,216,313	3,869	3,235
November-13	1,362,688	1,469,902	4,258	3,675
December-13	1,679,913	1,776,472	5,000	4,354
January-14	1,782,457	1,748,792	5,064	4,461
February-14	1,488,920	1,457,315	4,653	4,140
March-14	1,399,091	1,502,819	4,164	3,683
April-14	1,316,233	1,184,503	3,739	3,219
May-14	1,294,450	1,334,476	3,853	3,271

Contract Month	Total Load (MWh)		Average Load (MWh)	
	On-Peak	Off-Peak	On-Peak	Off-Peak
June-14	1,851,927	1,553,489	5,512	4,046
July-14	2,101,193	2,241,182	5,969	5,717
August-14	2,248,679	1,823,215	6,692	4,469
September-14	1,538,391	1,466,300	4,579	3,818
October-14	1,314,273	1,350,807	3,571	3,593
November-14	1,457,566	1,436,711	4,795	3,454
December-14	1,699,468	1,791,473	4,828	4,570
January-15	1,712,873	1,829,337	5,098	4,484
February-15	1,589,745	1,499,038	4,968	4,259
March-15	1,492,749	1,461,870	4,241	3,729
April-15	1,276,826	1,257,106	3,627	3,416
May-15	1,382,300	1,294,226	4,320	3,052
June-15	1,754,034	1,617,539	4,983	4,395
July-15	2,209,367	2,145,187	6,004	5,705
August-15	2,231,981	1,823,774	6,643	4,470
September-15	1,370,867	1,571,351	4,080	4,092
October-15	1,431,746	1,223,736	4,067	3,122
November-15	1,446,176	1,411,890	4,519	3,530
December-15	1,597,860	1,844,815	4,539	4,706
January-16	1,785,338	1,748,506	5,579	4,124
February-16	1,494,489	1,458,271	4,448	4,051
March-16	1,404,947	1,503,241	3,818	3,998
April-16	1,323,024	1,186,400	3,938	3,090
May-16	1,364,882	1,277,753	4,062	3,132

ATTACHMENT H: Commonwealth Edison Contract Volumes to Secure in Spring 2011 Procurement Cycle

Commonwealth Edison Off Peak Contract Volumes to Secure in 2011 Procurement Cycle

Contract Month	Off-Peak Contract Volumes to Secure (MW)						
	Projected Volume (MW)	Swap Volumes (MW)	2010 Procurement Volumes (MW)	Residual Volumes (MW)	2011 IPA Procurement (MW)	2012 IPA Procurement (MW)	2013 IPA Procurement (MW)
June-11	4,221	3,000	0	1,221	1200	0	0
July-11	5,286	3,000	700	1,586	1600	0	0
August-11	4,849	3,000	400	1,449	1450	0	0
September-11	3,818	3,000	0	818	800	0	0
October-11	3,311	3,000	0	311	300	0	0
November-11	3,741	3,000	0	741	750	0	0
December-11	4,391	3,000	100	1,291	1300	0	0
January-12	4,484	3,000	150	1,334	1350	0	0
February-12	4,164	3,000	0	1,164	1150	0	0
March-12	3,729	3,000	0	729	750	0	0
April-12	3,274	3,000	0	274	250	0	0
May-12	3,302	3,000	0	302	300	0	0
June-12	4,212	3,000	0	1,212	0	1200	0
July-12	5,258	3,000	0	2,258	700	1550	0
August-12	4,850	3,000	0	1,850	400	1450	0
September-12	3,777	3,000	0	777	0	800	0
October-12	3,255	3,000	0	255	0	250	0
November-12	3,677	3,000	0	677	0	700	0
December-12	4,351	3,000	0	1,351	50	1300	0
January-13	4,460	3,000	0	1,460	100	1350	0
February-13	4,143	3,000	0	1,143	0	1150	0
March-13	3,684	3,000	0	684	0	700	0
April-13	3,224	3,000	0	224	0	200	0
May-13	3,260	3,000	0	260	0	250	0
June-13	4,251	0	0	4,251	1500	1500	1250
July-13	5,265	0	0	5,265	1850	1850	1550
August-13	4,878	0	0	4,878	1700	1700	1500
September-13	3,742	0	0	3,742	1300	1300	1150
October-13	3,235	0	0	3,235	1150	1100	1000
November-13	3,675	0	0	3,675	1300	1250	1100
December-13	4,354	0	0	4,354	1500	1550	1300
January-14	4,461	0	0	4,461	1550	1550	1350
February-14	4,140	0	0	4,140	1450	1450	1250
March-14	3,683	0	0	3,683	1300	1300	1100
April-14	3,219	0	0	3,219	1150	1100	950
May-14	3,271	0	0	3,271	1150	1150	950

Contract Month	Off-Peak Contract Volumes to Secure (MW)						
	Projected Volume (MW)	Swap Volumes (MW)	2010 Procurement Volumes (MW)	Residual Volumes (MW)	2011 IPA Procurement (MW)	2012 IPA Procurement (MW)	2013 IPA Procurement (MW)
June-14	4,259	0	0	4,259	0	1500	1500
July-14	5,287	0	0	5,287	0	1850	1850
August-14	4,910	0	0	4,910	0	1700	1750
September-14	3,711	0	0	3,711	0	1300	1300
October-14	3,234	0	0	3,234	0	1150	1100
November-14	3,672	0	0	3,672	0	1300	1250
December-14	4,362	0	0	4,362	0	1550	1500
January-15	4,465	0	0	4,465	0	1550	1600
February-15	4,125	0	0	4,125	0	1450	1450
March-15	3,681	0	0	3,681	0	1300	1300
April-15	3,223	0	0	3,223	0	1150	1100
May-15	3,285	0	0	3,285	0	1150	1150
June-15	4,273	0	0	4,273	0	0	1500
July-15	5,278	0	0	5,278	0	0	1850
August-15	4,943	0	0	4,943	0	0	1750
September-15	3,711	0	0	3,711	0	0	1300
October-15	3,238	0	0	3,238	0	0	1150
November-15	3,674	0	0	3,674	0	0	1300
December-15	4,359	0	0	4,359	0	0	1550
January-16	4,465	0	0	4,465	0	0	1550
February-16	4,115	0	0	4,115	0	0	1450
March-16	3,686	0	0	3,686	0	0	1300
April-16	3,221	0	0	3,221	0	0	1150
May-16	3,278	0	0	3,278	0	0	1150

Commonwealth Edison Peak Contract Volumes to Secure in 2011 Procurement Cycle

Contract Month	Peak Contract Volumes to Secure (MW)						
	Projected Volume (MW)	Swap Volumes (MW)	2010 Procurement Volumes (MW)	Residual Volumes (MW)	2011 IPA Procurement (MW)	2012 IPA Procurement (MW)	2013 IPA Procurement (MW)
June-11	5261	3000	650	1611	1600	0	0
July-11	7223	3000	2000	2223	2200	0	0
August-11	6722	3000	1650	2072	2050	0	0
September-11	4579	3000	150	1429	1450	0	0
October-11	3912	3000	0	912	900	0	0
November-11	4338	3000	0	1338	1350	0	0
December-11	5058	3000	500	1558	1550	0	0
January-12	5098	3000	550	1548	1550	0	0
February-12	4731	3000	300	1431	1450	0	0
March-12	4241	3000	0	1241	1250	0	0
April-12	3800	3000	0	800	800	0	0
May-12	3927	3000	0	927	950	0	0
June-12	5220	3000	0	2220	650	1550	0
July-12	7233	3000	0	4233	2050	2200	0
August-12	6672	3000	0	3672	1650	2000	0
September-12	4509	3000	0	1509	150	1350	0
October-12	3891	3000	0	891	0	900	0
November-12	4304	3000	0	1304	0	1300	0
December-12	4993	3000	0	1993	500	1500	0
January-13	5072	3000	0	2072	550	1500	0
February-13	4670	3000	0	1670	250	1400	0
March-13	4181	3000	0	1181	0	1200	0
April-13	3759	3000	0	759	0	750	0
May-13	3878	3000	0	878	0	900	0
June-13	5211	0	0	5211	1800	1850	1550
July-13	7308	0	0	7308	2550	2550	2200
August-13	6700	0	0	6700	2350	2350	2000
September-13	4538	0	0	4538	1600	1600	1350
October-13	3869	0	0	3869	1350	1350	1150
November-13	4258	0	0	4258	1500	1500	1250
December-13	5000	0	0	5000	1750	1750	1500
January-14	5064	0	0	5064	1750	1800	1500
February-14	4653	0	0	4653	1650	1600	1400
March-14	4164	0	0	4164	1450	1450	1250
April-14	3739	0	0	3739	1300	1300	1150
May-14	3853	0	0	3853	1350	1350	1150

Contract Month	Peak Contract Volumes to Secure (MW)						
	Projected Volume (MW)	Swap Volumes (MW)	2010 Procurement Volumes (MW)	Residual Volumes (MW)	2011 IPA Procurement (MW)	2012 IPA Procurement (MW)	2013 IPA Procurement (MW)
June-14	5244	0	0	5244	0	1850	1800
July-14	7382	0	0	7382	0	2600	2550
August-14	6729	0	0	6729	0	2350	2350
September-14	4574	0	0	4574	0	1600	1600
October-14	3868	0	0	3868	0	1350	1350
November-14	4237	0	0	4237	0	1500	1450
December-14	5012	0	0	5012	0	1750	1750
January-15	5057	0	0	5057	0	1750	1800
February-15	4668	0	0	4668	0	1650	1600
March-15	4184	0	0	4184	0	1450	1500
April-15	3729	0	0	3729	0	1300	1300
May-15	3836	0	0	3836	0	1350	1350
June-15	5287	0	0	5287	0	0	1850
July-15	7435	0	0	7435	0	0	2600
August-15	6756	0	0	6756	0	0	2350
September-15	4571	0	0	4571	0	0	1600
October-15	3842	0	0	3842	0	0	1350
November-15	4240	0	0	4240	0	0	1500
December-15	5024	0	0	5024	0	0	1750
January-16	5054	0	0	5054	0	0	1750
February-16	4687	0	0	4687	0	0	1650
March-16	4195	0	0	4195	0	0	1450
April-16	3704	0	0	3704	0	0	1300
May-16	3868	0	0	3868	0	0	1350

ATTACHMENT B: ICC RULING ON IPA PROCUREMENT PLAN (10-0563)

STATE OF ILLINOIS

ILLINOIS COMMERCE COMMISSION

Illinois Power Agency	**:**	
	:	**10-0563**
Petition for Approval of	**:**	
Procurement Plan.	**:**	

<u>ORDER</u>

DATED: December 21, 2010

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STATE OF ILLINOIS

ILLINOIS COMMERCE COMMISSION

Illinois Power Agency	**:**	
	:	**10-0563**
Petition for Approval of	**:**	
Procurement Plan.	**:**	

ORDER

By the Commission:

I. BACKGROUND

As set forth more specifically therein, Section 16-111.5(d)(2) of the Public Utilities Act ("PUA"), 220 ILCS 5/1-101 et seq., requires the Illinois Power Agency ("IPA") to prepare a power procurement plan ("Draft Plan"), which is to be posted on the IPA and Illinois Commerce Commission ("Commission") websites. The purpose of the power procurement plan is to secure electricity commodity and associated transmission services to meet the needs of eligible retail customers in the service areas of Commonwealth Edison Company ("ComEd") and Ameren Illinois Company ("AIC").[1] Section 16-111.5(d)(2) does not require that the Draft Plan be docketed by the Commission. Any comments on the Draft Plan are to be submitted to the IPA, for review by the IPA. The PUA requires the IPA to make revisions as necessary based on the comments submitted to it, and then to file the plan as revised with the Commission. As such, the only plan the IPA is required to formally file with the Commission, and the one that is actually before the Commission for its review in this proceeding, is the one containing the IPA's post-comment revisions. On September 29, 2010, the IPA filed with the Commission its third annual power procurement plan ("Plan") initiating this proceeding.

Upon the annual filing of the Plan with the Commission, Section 16-111.5(d)(3) of the PUA provides that within five days thereof, any person objecting to the Plan shall file an objection with the Commission. The same subsection also provides that the Commission shall enter an order confirming or modifying the Plan within 90 days after the filing of the Plan. The Plan was filed on September 29, 2010; thus, the deadline is December 28, 2010. Under Section 16-111.5(d)(4), the Commission shall approve the Plan, including expressly the forecast used in the Plan, if the Commission determines that it will ensure adequate, reliable, affordable, efficient, and environmentally

[1] AIC came into existence on October 1, 2010 with the merger of Central Illinois Light Company d/b/a AmerenCILCO and Illinois Power Company d/b/a AmerenIP into Central Illinois Public Service Company d/b/a AmerenCIPS and subsequent name change of AmerenCIPS to Ameren Illinois Company. Although one legal entity as of October 1, 2010, the rate areas of AmerenCIPS, AmerenCILCO, and AmerenIP remain as Rate Zone 1, Rate Zone 2, and Rate Zone 3, respectively.

sustainable electric service at the lowest total cost over time, taking into account any benefits of price stability.

Section 16-111.5(e) specifies the major components to be included in the procurement process. Section 16-111.5(e)(4) provides that a Procurement Administrator shall design and issue a request for proposals ("RFPs") to supply electricity in accordance with each utility's Plan, as approved by the Commission. The IPA may select one Procurement Administrator for ComEd and one for AIC. The RFPs shall set forth a procedure for sealed, binding commitment bidding with pay-as-bid settlement, and provision for selection of bids on the basis of price. Section 16-111.5(f) concerns the confidential reports to be submitted to the Commission by the Procurement Administrator and Procurement Monitor after the opening of the sealed bids. Subsection (f) provides further that the Commission shall review the confidential reports submitted by the Procurement Administrator and Procurement Monitor, and shall accept or reject the recommendations of the Procurement Administrator within two business days after receipt of the reports.

II. PROCEDURAL HISTORY

Following the receipt of the IPA's Plan on September 29, 2010, the following entities filed petitions for leave to intervene: the Attorney General on behalf of the People of the State of Illinois ("AG"), AIC, ComEd, Constellation Energy Commodities Group, Inc. ("CECG"), Citizens Utility Board, Duke Energy Generation Services Holding Company, Inc. ("Duke"), Environmental Law and Policy Center ("ELPC"), Exelon Generation Company, LLC ("ExGen"), Horizon Wind Energy LLC ("Horizon"), Iberdrola Renewables, Inc. ("Iberdrola"), Illinois Competitive Energy Association ("ICEA"), Illinois Wind Energy Association ("IWEA"), Natural Resources Defense Council ("NRDC"), Retail Energy Supply Association ("RESA"), TradeWind Energy, LLC ("TradeWind"), and Wind on the Wires ("WOW"). The Administrative Law Judge granted each petition for leave to intervene. Of those that intervened, AIC, CECG, ComEd, Duke, Iberdrola, RESA, and WOW each filed objections to the plan. Commission Staff ("Staff") filed objections as well.

At its October 6, 2010 Bench Session, the Commission determined, pursuant to Section 16-111.5(d)(3), that no hearing was necessary. Thereafter the Administrative Law Judge set a schedule for responses to the objections, and replies thereto. AIC, CECG, ComEd, ExGen, IPA, NRDC, Staff, and WOW each filed a response. AIC, ComEd, Duke, Iberdrola, IPA, RESA, Staff, and WOW each filed a reply.

On November 10, 2010, Iberdrola filed motions seeking modifications to the schedule and leave to submit supplemental comments offering a compromise on the issue of procuring renewable resources. The Administrative Law Judge granted Iberdrola's motions on November 12, 2010 and set a schedule for responses to the supplemental comments, and replies thereto. AIC, ComEd, Duke, ELPC, ExGen, Horizon, IPA, IWEA, RESA, Staff, TradeWind, and WOW each filed a response to the supplemental comments. ComEd, Iberdrola, IPA, RESA, and Staff each filed replies thereto.

On November 16, 2010, ComEd filed a motion seeking leave to update its load forecast. ComEd had indicated in its previously filed objections to the Plan that it would be offering an updated load forecast, as it had done in previous procurement dockets. No party opposed ComEd's motion.

A Proposed Order was served on the parties. The AG, AIC, ComEd, ExGen, ICEA, IPA, RESA, Staff, and WOW each filed a Brief on Exceptions. ELPC and NRDC jointly filed a Brief on Exceptions. The AG, AIC, ComEd, ExGen, Horizon, IPA, IWEA, RESA, Staff, and WOW each filed a Brief in Reply to Exceptions. Iberdrola and Duke jointly filed a Brief in Reply to Exceptions. The Briefs on Exceptions and Briefs in Reply to Exceptions were considered in the preparation of this Order.

III. OVERVIEW OF THE IPA'S PROPOSED PROCUREMENT PLAN

This section of the Order describes the IPA’s Plan as filed on September 29, 2010, after receipt by the IPA of comments from others. Proposed modifications to the Plan are described later in this Order. According to the IPA, the purpose of the Plan is to detail a procurement approach that will secure electricity commodity and associated transmission services, plus required renewable energy assets, to meet the supply needs of eligible retail customers served by ComEd and AIC. Section 16-111.5 of the PUA defines “eligible retail customers” 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.

The Plan outlines a procurement strategy for the period of June 2011 through May 2016 based on detailed five-year demand forecasts provided by AIC and ComEd. Because existing contracts are in place for a significant portion of the load needed to meet consumers’ electricity needs over the near term, the IPA states that procurement under its auspices will initially be limited to meeting residual consumer demand not covered by existing contracts.

The IPA proposes to maintain the core elements of the procurement approach used in the prior procurement cycles. Specifically, the IPA proposes that the procurement events be conducted through a two-stage process oriented around a RFP for each wholesale product sought. The first stage of the RFP will establish a pool of qualified bidders while the second stage will solicit bids for scheduled volumes of wholesale product. For ComEd, the resources sought through the RFP events will be energy, demand response in lieu of capacity, and renewable energy resources. For AIC, the resources sought through the RFP events will be energy, capacity, and renewable energy resources. The IPA proposes to hold primary procurement events during the spring of 2011, when it would seek the volumes of wholesale products identified in the Plan. Further, the IPA proposes optional procurements of up to an additional 10% of projected portfolio requirements in any month for the second and third planning year of the Plan that is below the 100% subscription level.

The IPA plans to retain the services of the Procurement Administrator(s) through a Request for Qualifications ("RFQ") and subsequent RFPs. The IPA proposes for the RFQ and RFP to solicit offers from bidders seeking to provide comprehensive administrator responsibilities for one or both ComEd's and AIC's procurement events (i.e. power, demand response in lieu of capacity, and renewable energy resources for ComEd and/or power, capacity, and renewable energy resources for AIC), as well as offers to administer single wholesale product solicitations for ComEd and AIC (i.e. power resources for both ComEd and AIC, renewable energy resources for both ComEd and AIC). The IPA states that the RFPs for wholesale products will seek offers for fixed volumes at fixed prices.

The IPA proposes to allow energy efficiency to be treated as an energy supply resource. The IPA states that the price for the product would be negotiated after the closing of the spring 2011 solicitations for the more traditional physical and financial swap products through a competitive solicitation. The IPA says the combined costs of traditional energy, capacity, and renewable energy assets within the IPA portfolio after the spring 2011 procurement events will be used to develop a cost-effectiveness benchmark for the energy efficiency procurements. The IPA will not procure resources that are required to meet the Energy Efficiency Portfolio Standards ("EEPS") set forth in Section 8-103 of the PUA.

The IPA proposes that capacity resources for ComEd be delivered through the PJM Interconnection ("PJM") capacity markets. For AIC, the IPA indicates that capacity resources that are qualified by the Midwest Independent Transmission System Operator ("MISO") to issue Planning Resource Credits ("PRC") will be sought for the AIC load.

Consistent with Section 16-111.5(b)(3)(ii), the IPA proposes that solicitations seeking cost-effective demand response assets occur for both utilities. The IPA notes that as the statute does not require or infer that these assets be procured in lieu of capacity, that they will be sought independent of the capacity resource plans specified in the Plan.

The IPA plans to acquire Renewable Energy Credits ("REC") for a single compliance year (June 2011 through May 2012). The IPA proposes to continue the consolidation of REC procurement processes and procedures started in 2010, and seeks to unify standard terms and conditions between AIC and ComEd with regard to REC contracts. Therefore, the IPA recommends that the utilities' REC contracts include

(1) collateral requirements that equal to 10% of remaining contract value and (2) unsecured credit limits for creditworthy REC suppliers.

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 last two procurement dockets of scheduling procurements of wholesale energy resources relatively evenly over three-year periods. The IPA states that while liquidity indicators for the 24- to 36-month horizons within wholesale energy markets have diminished somewhat, bidding activity in the spring 2010 procurement cycle for contracts in that cycle's 24- to 36-month range indicates an adequate level of competition and bidder interest.

As prescribed in the prior two procurements proceedings, the IPA relates that 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 can not 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, the 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.

The IPA points out that Section 16-113 of the PUA provides for generation services to be declared competitive for classes of customers when the Commission finds sufficient evidence of competition to meet legal standards and that certain classes have been declared competitive as a matter of law under Section 16-113. The IPA states that all ComEd commercial and industrial customer classes with demand greater than 100 kilowatts ("kW") are deemed competitive, as are AIC customers with demand of at least 400 kW. According to the IPA, the statute allows ComEd customers with demand below 400 kW, and AIC customers with demand between 400 kW and 1 megawatt ("MW"), to continue to purchase power and energy from the utility through May 31, 2010, provided that no customer in a class that has been declared competitive is allowed to return to bundled utility service after having switched to an alternative provider. The IPA states that after that date, ComEd and AIC will procure power for a customer in a class deemed competitive only by purchasing electricity 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 alternative retail electric supplier ("ARES").

The IPA procurement plans are designed to accommodate the electricity needs of customers who continue buying bundled service electricity from ComEd and AIC. According to the latest published data for the Commission’s Electric Switching Statistics – (a/k/a Direct Access Service Request "reports") (May 2010 for ComEd and AIC), only 40.7% of the total electricity usage by ComEd and AIC customers over the period was supplied through fixed price bundled utility service. The IPA says another 4.6% was delivered at Hourly Energy Pricing, and the remaining 55.7% was delivered through ARES. According to those same reports, 99.9% of ComEd and AIC residential customers remain on bundled rates. The IPA states that increasing the role of competitive supply options within all rate classes served by ComEd and AIC has been supported by recent developments and statutes. The IPA anticipates that the State's policy of supporting competitive electricity markets will continue and strengthen, and that eligible retail consumers currently served through the IPA portfolio will migrate towards ARES options.

IV. LOAD FORECASTS

Among the areas covered in the Plan is load forecast. The IPA states that pursuant to Section 16-111.5(d)(1) of the Act, on July 13 and July 15, 2010, ComEd and AIC, respectively, submitted to the IPA separate load forecasts. The IPA adds that it requested, and ComEd and AIC also provided, detailed descriptions of the statistical methods and assumptions underlying the projections. The IPA indicates that it has not independently validated the load forecast models and results provided by ComEd and AIC. Copies of ComEd's and AIC's load forecast submittals are included in Attachments A and E to the Plan.

The IPA says it relied on load forecasts from ComEd and AIC as best estimates for future consumption factored for the largely unknown variable of retail switching. According to the IPA, the creation of the Office of Retail Market Competition ("ORMD") within the Commission, and the passage of legislation to facilitate retail competition, indicate the potential for significant changes in retail switching among eligible retail customers. Since ComEd's and AIC's data projections are updated annually, the IPA states that it will further adjust load projections should retail switching exceed ComEd's and AIC's projections. The IPA says that for the purpose of this load projection adjustment, a difference will be deemed to be significant if the adjustment would result in a 200 MW or larger change in the supply quantity. The IPA says this adjustment will be based on the impact of retail switching among eligible retail customers based on Commission generated reports.

A. ComEd's Load Forecast

According to the IPA, the ComEd customer classes declared competitive by the PUA include those customers with demand greater than 100 kW. Customers with demand of greater than 100 kW are no longer eligible for bundled service and are not included in the load forecasts. The IPA indicates that ComEd utilizes a forecasting process based on econometric models that produce monthly sales forecasts for primary customer classes. The IPA states that the 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 IPA indicates that ComEd's statistical models are measured for accuracy against past period consumption volumes for each customer class. According to the IPA, comparisons between predicted and actual consumption volumes are highly correlated and are the best models available for forecasting loads for the eligible retail customers. The IPA states that forecasted portfolio volumes are generated by altering model variables within expected ranges and examining model outputs. According to the IPA, resulting High, Expected, and Low volume scenarios are generated, and it has selected the Expected Load Model as the basis of the Plan for the ComEd portfolio.

Section 8-103(c) of the PUA establishes specific requirements for utility company demand response programs. Section 16-111.5(b) of the PUA requires that the Plan shall include an analysis of the impact of demand side initiatives established by Section 8-103(c). The IPA states that 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 each utility intends to implement demand response programs sufficient to achieve their targeted peak reductions. Based on ComEd’s analysis, the IPA says the effective aggregated reduction in ComEd’s maximum system load requirements for eligible retail customers due to demand response programs is projected to be 42.0 MW in 2011, 53.1 MW in 2012, 63.6 MW in 2013, 74.2 MW in 2014, and 85.0 MW in 2015. 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. The IPA indicates that the annual aggregate reductions in ComEd’s supply requirements to be acquired through the RFP process (net of customer switching) is projected to be: 599.8 gigawatt-hours ("GWh") in 2011, 931.1 GWh in 2012, 1,307.7 GWh in 2013, and 1,683.9 GWh in 2014, and 2,059.9 GWh in 2015. 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 ComEd (as well as AIC).

B. AIC's Load Forecast

The IPA states that AIC's five-year hourly load forecast identifies load projections for eligible retail customers. AIC, the IPA says, utilizes a statistically adjusted end-use model as the basis of its load forecasting process. The IPA adds that after adjusting consumption data for weather, seasonal variables, and economic conditions, a detailed core consumption model was developed. The IPA states that AIC's load forecasting process begins with a multi-year analysis of historical loads. The IPA says recorded hourly loads are correlated to weather to generate a normalized full requirements load projection for each customer class. The normalized full requirements load projection for each customer class is then adjusted by losses, expected growth rates, retail competition switching trends, and results of statutory and other programs related to demand response and energy efficiency to yield a five-year projection of wholesale supply, capacity, and renewable energy resource requirements.

The IPA says comparisons between predicted and actual consumption volumes are highly correlated and are the best models available for forecasting loads for the eligible retail customers. 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. The IPA selected the Expected Load Model as the basis of the Plan for the AIC portfolio.

For the purpose of projecting loads for this year’s Plan, the IPA assumes that AIC intends to implement demand response programs sufficient to achieve its targeted peak reductions. Based on AIC’s analysis, the IPA says the aggregated reduction in AIC’s maximum system load requirements for eligible retail customers due to demand response programs is projected as: 12 MW in 2011, 16 MW in 2012, 20 MW in 2013, 23 MW in 2014, and 26 MW in 2015. The IPA indicates that it plans to request validation of the ability to dispatch the demand response assets included in the AIC forecast in the near future. The IPA also notes that these demand response values are effectively treated as pre-existing PRC credits within capacity resources projections for AIC. The IPA has also included the impacts of the AIC energy efficiency programs based on AIC's analysis of the current and projected programs. The annual incremental reductions in AIC’s supply requirements to be acquired through the RFP process (net of customer switching) is projected to be: 106.8 GWh in 2011, 207.7 GWh in 2012, 298.2 GWh in 2013, 349.5 GWh in 2014, and 365.6 GWh in 2015.

V. PORTFOLIO DESIGN

Citing Section 16-111.5(d)(4) of the Act, the IPA contends its priorities for the portfolio design are "to ensure adequate, reliable, affordable, efficient, and environmentally sustainable electric service at the lowest total cost over time, taking into account any benefits of price stability." The IPA indicates that the challenge it faces is to achieve low and stable prices in a market where prices change constantly and sometimes dramatically. In the IPA's view, the task is complicated by variables that may significantly increase or decrease portfolio requirements over the short term (such as weather) or over the longer term (such as customer migration away from the IPA portfolio). The IPA claims that 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 raising 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.

A. Risk Assessment

According to the IPA, Section 16-111.5(b)(3)(vi) of 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."

The IPA asserts that the portfolio is exposed to price risk on two levels: (1) long-term cost trend risk, and (2) short-term clearing risk. The IPA claims that 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, which all interact against variable market demand and are reflected in the day-ahead and real-time prices yielded by the regional wholesale markets. According to the IPA, these real-time price patterns translate roughly into future prices for electricity as reflected in financial markets. The IPA states that mitigating long-term price risk is achieved by taking multiple positions within the market. Within the context of the IPA portfolio, the IPA explains that multiple positions are taken by following a laddered approach to securing fixed price electricity contracts at different times over a medium term horizon. The IPA indicates that 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. Mitigating price risk carries a premium, however, and the IPA maintains that its approach provides necessary protection against longer term price volatility and escalation.

Short-term clearing risk, the IPA avers, 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. The IPA asserts that short-term risks are largely mitigated through the use of load averaging and securing monthly contracts against those load averages.

The IPA points out that in the Illinois electricity market, the State policy is to support electricity choice and competitive retail markets with the IPA portfolio of fixed price contracts serving as the "default" rate provider. The portfolio is exposed to load uncertainty risk due to inelasticity of demand among many portfolio participants, meaning that consumption does not diminish significantly when prices are high. The IPA observes that consumption by bundled service customers is relatively inelastic. In the IPA's view, this is due in large part to current tariff structures that do not expose customers to price variance. The IPA says inelasticity of demand represents risk insofar as portfolio participants who 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. The IPA states that inclusion of demand response and energy efficiency as alternative products within the procurement events could serve as effective tools in addressing price responsiveness and load shape.

Another source of load uncertainty risk, the IPA states, stems from the unknown pace of migration of eligible customers to ARES. The IPA notes that outside of recently competitively declared rate classes, competitive supply has not taken hold in the broader Illinois residential market. The IPA opines, however, that recent developments indicate that significant reductions to the barriers to retail competition in residential markets are on the near-term horizon. While the scale and rate of migration away from the IPA portfolio is not known, the IPA references statistics reported by the U.S. Department of Energy’s Energy Information Administration regarding the migration of natural gas customers away from bundled natural gas supply offered by Northern Illinois Gas Company d/b/a Nicor Gas Company, Peoples Gas Light and Coke Company, and North Shore Gas Company. The statistics indicate that some interest in alternative energy supply exists. The IPA states that in 2009, 9.3% of eligible residential consumers received natural gas supply from alternative retail gas suppliers. The IPA anticipates that higher migration rates are possible in electricity markets as tariff structure will allow ARES to make direct comparisons between their price offers and the annual fixed rate for energy available through ComEd and AIC and sourced to the IPA portfolio.

According to the IPA, migration of eligible retail customers to ARES presents risk to the portfolio insofar as migration can cause cost spiraling under certain conditions. The IPA provides an example that assumes that a high percentage of anticipated long-term load requirements for the IPA portfolio were secured with fixed volume contracts. The IPA further assumes that market prices decreased in the future (e.g. our recent market experience in 2008-2009). Finally, the IPA assumes that migration from the IPA portfolio to an ARES was free of barriers. The IPA claims that 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 ARES at the relatively lower market prices. As the number of bundled service customers eroded, the IPA says 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. The IPA states that while the purchase of receivables provisions in the PUA are 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, the IPA believes the 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.

According to the IPA, 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 end-use customer. The IPA maintains, however, that 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. The IPA believes collateral thresholds should remain at the levels used in the utilities' existing energy contracts unless there is consensus among the utilities, Procurement Administrator, Procurement Monitor, and Staff that a compelling reason warrants new collateral thresholds. The IPA insists that 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. The IPA recommends that contracts entered into as a result of the procurement process should be executed through one of the following methods:

- International Swaps and Derivatives Association ("ISDA") agreement for financial instruments such as fixed/floating rate swaps; or
- Central counterparty clearing for standardized financial instruments on exchange traded contracts; or
- An Edison Electric Institute ("EEI") agreement for physical products.

Time frames for securing products and services, the IPA avers, present risk to the portfolio insofar as the underlying volatility in electricity markets places a premium on time. The IPA states that compliance with the PUA leads to procurement events that occur as many as nine months after load projections are made and eight months after the Plan is developed. According to the IPA, 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. The IPA notes that in the most recent procurement process, revised load projections from ComEd and AIC were submitted in response to downward projections in load requirements due to economic weakness within the region.

While the portfolio design recommended by the IPA focuses on mitigating upside price risk, as seen in recent periods, however, prices in the wholesale market can and do move down. This possibility supports, in the IPA's opinion, continuing the practice of laddered procurement over a three-year period in the cases of energy and capacity resources on an annual basis. To further mitigate the risk of price decline, the IPA recommends that the Commission allow for optional procurements for energy only. The IPA says these optional procurements would be limited to only an additional 10% of projected portfolio requirements in any month for the second and third planning years covered by the Plan that is below the 100% subscription level. The optional procurements, the IPA avers, would be triggered only when market indices demonstrate that prices for energy supply contracts for the target months are at least 10% below the average weighted price of fixed price contracts already secured by ComEd and AIC for those months and such prices are below the prices for the most recently completed planning year procurement event. The IPA says the optional procurements would be limited to participation by bidders qualified in and the terms and conditions agreed to in the spring 2011 solicitation, and allowed only with the authorization of the Commission. The IPA states that after the optional procurement event(s) for energy hedges, the maximum subscription quantity shall be 100% for year 1, 80% for year 2, 45% for year 3 and 0% for years 4 and 5.

Fuel costs, the IPA states, present risk to the portfolio insofar as fuel costs are the primary drivers of generation costs. Even more important, in the IPA's view, 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. The IPA states that natural gas-fueled plants are the marginal producers during the summer months in both the PJM and MISO regions while coal-fueled plants are the marginal producers for the majority of hours in PJM and MISO. The IPA avers that electricity market prices incorporate fuel price risk. In the IPA's view, mitigation options outside of the proposed portfolio design would have limited utility as the portfolio design is geared towards mitigating general electricity price risk.

The IPA asserts that weather patterns present risk to the portfolio because weather-related changes in demand and supply correlate with spot prices. Particular risks, the IPA states, 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. The IPA avers that 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, the IPA indicates spot prices for electricity would drop. With mild weather effectively reducing demand for electricity, consumption would drop below projections based on average temperatures. The IPA suggests that 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 and the resulting financial losses would be applied against the portfolio.

If warm summer weather were to increase regional cooling loads, the IPA says spot prices for electricity would rise. With warmer weather effectively increasing demand for electricity within the portfolio, the IPA suggests consumption would increase above projections that were based on an assumption of marginally lower average temperatures. The IPA states that 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 and the resulting increased costs would be applied against the portfolio.

The IPA observes that AIC operates in MISO, while ComEd operates in PJM. According to the IPA, risks associated with these markets are new transmission asset related costs, and higher integration costs associated with wind energy developments. The IPA states that recent projections indicate plans for billions of dollars in transmission investments throughout the MISO and PJM regions. The IPA avers that some of the transmission system upgrades propose to extend transmission between wind generating regions in the western spans of the MISO region and larger population centers in the eastern reaches of MISO as well as PJM. According to the IPA, future transmission costs will be borne by MISO and PJM participants via tariff.

The IPA also suggests that the rapid development of wind-based renewable electricity generation in the PJM and MISO regions will likely cause upward pressure on transmission costs because wind facilities tend to be in remote locations that may not have adequate existing transmission to bring power to load centers. In addition, the IPA says system operators will need to alter system operations to accommodate the intermittent nature of wind energy. According to the IPA, past estimates of costs relative to integrating wind assets into regional transmission portfolios range from as low as $2.11/megawatt-hour ("MWh") for 15% wind penetration within the portfolio to $4.41/MWh for a penetration level of 25%. The IPA says some of these costs may be offset by contributions of wind assets towards system reliability and other ancillary services. The IPA adds that recently, the Bonnevile Power Administration ("BPA") issued a final decision for its 2010 rate case. The IPA states that in the final rate case decision, BPA authorized charging wind generators a “Wind Integration Rate” of $1.29/kilowatt-month (approximately $5.70/MWh). The IPA says the approved rate was substantially lower than the originally requested rate of $2.79/kilowatt-month (approximately $12.00/MWh). According to the IPA, the purpose of the fee was to cover the costs associated with the higher load balancing costs associated with facilitating the variable nature of wind asset output. In return for the lower than originally requested fee, wind generators agreed to a first-ever curtailment arrangement.

The IPA contends that it 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. The IPA observes, however, that 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. The IPA also states that market conditions generally relate to the drivers of market prices, customer usage, and customer switching levels. The IPA claims that these variables are included in the statistical modeling it conducted relative to the portfolio design. The IPA believes its analysis provides a reasonable representation of the significant risks associated with the June 2011 – May 2016 horizon, and that its Plan provides reasonable protection for customers from likely risk factors. As a result, given the guidance provided under the PUA, the IPA does not offer an alternative to its recommended portfolio.

B. Modeling Approach

According to the IPA, the options for electric energy products fall into two general categories: fixed price and variable price products. The IPA states that 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. The IPA adds that 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.

The IPA states that variable price products allow the purchase of electricity at prices set by supply and demand for electricity at the time of consumption. The IPA indicates that locational marginal prices (“LMP”) provided through regional transmission organizations ("RTOs") are the basis of variable price products in organized wholesale markets. Variable price products, the IPA states, 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.

The IPA asserts that in order to manage procurement for a variable population with uncertain loads in an unpredictable market, its Plan utilizes methods similar to those used by investors to manage market portfolio risks. According to the IPA, 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 IPA observes that the risk profile of its proposed portfolio changes over time. Accordingly, the IPA indicates that it will be making process improvements that allow for continuous monitoring and annual adjustments to the portfolio strategy as each Plan is developed.

Next, the IPA discusses the premises upon which it constructed its portfolio and risk management approach, beginning with physical and financial product parity. According to the IPA, 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, the IPA says, 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.

The IPA views existing forward markets as providing sufficient liquidity to assure price competition for up to three years. The IPA believes that 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. According to the IPA, past market performance with regard to price volatility, trending, and correlations is the basis of the assumptions incorporated into IPA modeling and evaluations. The IPA indicates that it used three metrics to identify price risk:

- 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, and
- Metric C: Longitudinal Variance – the extent to which prices in the latter years of a plan vary from current futures market prices.

To establish a model portfolio for ComEd and AIC, the IPA indicates that a Monte Carlo[2] model using Excel and Crystal Ball software 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. The IPA asserts that with efficient market prices, all portfolios should have the same expected value; however, price stability (measured as standard deviation) can vary. The IPA says that to evaluate the price stability of the different portfolios, volatility in the three price metrics was measured and combined to generate a composite risk metric for use in the evaluation. The composite metric that the IPA created is the square root of the average (A) Year-over-Year Price Variance, (B) Mark-to-Market Price Variance, and (C) Longitudinal Variance.

The IPA states that a set of potential portfolios was evaluated with multiple model runs against the risk metric defined above. The IPA says there are three main sections to the model, the first of which is the price section. According to the IPA, the model uses monthly forward peak and off-peak New York Mercantile Exchange ("NYMEX") pricing through 2016 as of August 10, 2010. The IPA views NYMEX as an appropriate indicator of future prices in the nearer term where market liquidity is sufficient to generate pricing competition. The IPA says that for periods after 2013, 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 IPA indicates that 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, the IPA states, include changes in prices due to all factors, including fuel price movements. The IPA says market price volatility was selected as the appropriate representative of market price risk because the utilities do not own generation and therefore can not control variables such as fuel expense.

According to the IPA, 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, the IPA says, 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

[2] In simple terms, a Monte Carlo model is a problem solving technique used to approximate the probability of certain outcomes by running multiple trial runs, called simulations, using random variables.

first year of the forward curve. Consequently, the IPA indicates that the forward prices in the analysis move together but with a muted effect as one goes out in time.

In the IPA's view, 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), the IPA says 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.

The second main section of the model relates to estimated load requirements. The IPA avers that 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 IPA indicates that the model starts with the base load estimates for eligible retail customers supplied by ComEd and AIC on July 15, 2011 and then allows the Monte Carlo simulation to vary the loads based on both weather and non-weather (economy and retail switching) factors. The IPA says the model assumes a triangular distribution for the loads based on the high/low load forecasts supplied by ComEd and AIC.

According to the IPA, 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) from the amount hedged through the swap arrangements. In addition, the IPA says the model does factor for intentional oversubscription of planned volumes in summer months (July and August) and non-summer periods to investigate whether procuring more or less than 100% of net open requirements would reduce a model portfolio’s risk.

The IPA indicates that 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. According to the IPA, the model then estimates the effective cost associated with the swap contracts (price and quantity fixed), the cost of any RFP purchases, transmission costs for ancillary services 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.

According to the IPA, a key factor in the analysis is the cost associated with the load shape that results from customers using relatively more energy when prices are high and relatively less energy when prices are low. The IPA says 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.

The IPA provides a simple example of a price/load gross-up factor in which it assumes a world with three hours where the customer loads were typically 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. According to the IPA, since the price is highest when loads are highest, the actual average cost to serve the load is \$116.7/MWh ((10*50+20*100+30*150)/60 or \$116.7/MWh). The IPA says that in this example, the load/price gross-up factor is 16.7% (\$116.7/\$100 – 1).

According to the IPA, 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. The IPA suggests that 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. The IPA says 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. In the IPA's view, while this result may not be intuitive, 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.

C. Proposed Portfolio Design

The IPA claims that the model was designed to help identify whether some portfolios may be superior to others 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. what mix of products) and 2) the scale of the procurement (i.e. the volume purchased relative to the expected future load requirement). The IPA explains that 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 by the IPA 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). The IPA says 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 indicates it focused on the 2013-2014 period. The IPA says it chose to look out this far 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.” According to the IPA, 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. The IPA states that 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 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, the IPA asserts that acquiring 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; and 30% of projected energy needs procured in the year in which power is to be delivered would yield the lowest and most stable prices, based on current market conditions. In the IPA's view, such a laddered procurement strategy 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. The IPA suggests this 35/35/30 model portfolio is analogous to dollar cost averaging in investing. The IPA notes that this laddering of energy supply contracts does not apply to the purchase of RECs.

Given the high-level nature of its analysis, the IPA states that the 35/35/30 recommendation can be thought of as representative of a range of procurement portfolios that may have very similar risk profiles. The IPA believes that 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 ComEd and AIC to a significant amount of load balancing transactions in the spot market, the IPA does not recommend additional exposure to the spot market at this time.

In the IPA's view, 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 IPA reports the model can not predict where prices will be in the next three- to five-year period. Instead, the IPA indicates that 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.

The IPA believes capturing low costs is another issue. Qualitative evaluation of the current markets indicate to the IPA that regulatory compliance may force a fair amount of coal generating assets out of the market within the next decade. Replacement capacity appears to the IPA to be planned, however, many queue applicants are renewable energy generators with little to no baseload capacity value. At this time, the IPA asserts that 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, the IPA believes 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.

VI. APPLICATION OF PROPOSED PORTFOLIO DESIGN

The IPA explains how the power and energy will be procured for delivery from June 1, 2011 through May 31, 2014 for ComEd’s and AIC's eligible retail customers. The IPA states that the utilities will meet the physical supply requirements of their projected loads for the specific rate classes identified in their respective load forecasts. ComEd's customer rate classes are defined as follows:

Rate Class	Description
• 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 kilowatt-hours ("kWh") per billing period
• Small –	Small Load, non-residential, less than 100 kW peak demand
• DD –	Dusk to Dawn Lighting
• GL –	General Lighting

AIC's customer rate classes for which supply will be procured are defined as follows:

Rate Class	Description
• 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 service
• QF	Qualified Facilities. The Company must procure energy from any qualifying facility meeting the requirements of Rider QF– Qualifying Facilities. Such qualifying purchases are considered to be preexisting purchases and shall be recovered in Accrued Expenses for the Purchased Electricity Adjustment.

A. Energy Supply Requirements

According to the IPA, energy required by ComEd's eligible retail customers comes from five sources. First, the swap contract with ExGen provides a financial hedge on 3,000 MW of around-the-clock (“ATC”) energy during the June 2011 – May 2013 period. Second, certain fixed price physical supply contracts were secured through the 2010 procurement process. Third, the IPA says it will solicit standard wholesale products through a sealed-bid RFP pursuant to the Plan approved in this proceeding. Fourth, the IPA states that balancing energy will be procured from the PJM-administered day-ahead and real-time energy markets. Lastly, ComEd will enter into agreements to purchase Energy Efficiency as Alternative Resource ("EEAR") from existing EEPS programs offered to eligible retail customers in the ComEd service region.

The IPA states that energy required by AIC's eligible retail customers also comes from five sources. First, a swap contract with Ameren Energy Marketing provides a financial hedge on 1,000 MW of ATC energy during the June 2011 – December 2012 period. Second, AIC has some existing financial hedges in place for the period June 2011 through May 2012. Such hedges were executed as a result of the 2010 procurement process. Third, AIC will enter into fixed price physical supply contracts to hedge price exposure for the residual volumes (IPA will solicit standard wholesale products through a sealed-bid RFP per this Plan). Fourth, the IPA indicates that, like ComEd, AIC will enter into agreements to purchase EEAR from existing EEPS programs offered to eligible retail customers in the AIC service region. Fifth, AIC will procure the physical energy necessary to meet its combined load requirements via the MISO day ahead and real-time energy markets.

In determining the granularity of the standard wholesale products to be procured through the RFP, the IPA says it recognized that if the products are defined in a way such that the MW 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. The IPA states however, that standard products traded in the wholesale market do not involve delivery quantities that vary within the 24 monthly on-peak/off-peak periods throughout the year, so the quantities of energy procured in the form of standard wholesale products can not approximate customer load shapes on a more granular basis than a monthly on-peak/off-peak basis.

Given these facts, the IPA plans for the Procurement Administrator to 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 ATC blocks during the period between June 2011 and May 2014, in whatever combinations are deemed appropriate by the Procurement Administrator, given the objectives described in this Plan. The IPA states that the target procurement quantities are determined by multiplying ComEd's and AIC'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 previous RFPs and ExGen and Ameren Energy Marketing swaps are subtracted from the target requirements. To the extent the calculated procurement quantity for a period is less than zero, the IPA says no energy will be procured for that period and existing positions will be maintained. The IPA also notes that calculations in the model are rounded to the nearest 50 MW. The IPA believes that 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.

According to the IPA, bidders will be provided an opportunity to bundle their bids for various products as determined by the Procurement Administrator after consulting with the IPA, utilities, the Procurement Monitor, and the Commission. By providing some flexibility for bundled bids, the IPA claims bidders will be better able to bid on the products for which they can offer the most competitive prices. The IPA says 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 by the IPA in the current procurement cycle, rounded to the nearest 50 MW, are shown in the tables below. The IPA notes that consistent with past practice, the contract volumes in the schedule include a 10% increased purchase volume for the on-peak periods in the months of July and August. According to the IPA, this increase is included to serve as a hedge against unforeseen increases in weather-related demand during those periods.

ComEd Peak Load Volumes to be Secured in 2011 Procurement Cycle by the IPA

Month	Year	Amount to be Procured (MW)	Year	Amount to be Procured (MW)	Year	Amount to be Procured (MW)
June	2011	1600	2012	650	2013	1800
July	2011	2200	2012	2050	2013	2550
August	2011	2050	2012	1650	2013	2350
September	2011	1450	2012	150	2013	1600
October	2011	900	2012	0	2013	1350
November	2011	1350	2012	0	2013	1500
December	2011	1550	2012	500	2013	1750
January	2012	1550	2013	550	2014	1750
February	2012	1450	2013	250	2014	1650
March	2012	1250	2013	0	2014	1450
April	2012	800	2013	0	2014	1300
May	2012	950	2013	0	2014	1350

ComEd Off-Peak Load Volumes to be Secured in 2011 Procurement Cycle by the IPA

Month	Year	Amount to be Procured (MW)	Year	Amount to be Procured (MW)	Year	Amount to be Procured (MW)
June	2011	1200	2012	0	2013	1500
July	2011	1600	2012	700	2013	1850
August	2011	1450	2012	400	2013	1700
September	2011	800	2012	0	2013	1300
October	2011	300	2012	0	2013	1150
November	2011	750	2012	0	2013	1300
December	2011	1300	2012	50	2013	1500
January	2012	1350	2013	100	2014	1550
February	2012	1150	2013	0	2014	1450
March	2012	750	2013	0	2014	1300
April	2012	250	2013	0	2014	1150
May	2012	300	2013	0	2014	1150

AIC Peak Load Volumes to be Secured in 2011 Procurement Cycle by the IPA

Month	Year	Amount to be Procured (MW)	Year	Amount to be Procured (MW)	Year	Amount to be Procured (MW)
June	2011	500	2012	500	2013	750
July	2011	750	2012	950	2013	950
August	2011	700	2012	950	2013	950
September	2011	500	2012	350	2013	650
October	2011	400	2012	100	2013	550
November	2011	450	2012	200	2013	550
December	2011	450	2012	400	2013	700
January	2012	550	2013	750	2014	750
February	2012	550	2013	700	2014	700
March	2012	450	2013	550	2014	600
April	2012	450	2013	500	2014	500
May	2012	400	2013	550	2014	550

AIC Off-Peak Load Volumes to be Secured in 2011 Procurement Cycle by the IPA

Month	Year	Amount to be Procured (MW)	Year	Amount to be Procured (MW)	Year	Amount to be Procured (MW)
June	2011	500	2012	150	2013	550
July	2011	400	2012	450	2013	700
August	2011	450	2012	400	2013	700
September	2011	450	2012	200	2013	600
October	2011	350	2012	0	2013	500
November	2011	350	2012	50	2013	500
December	2011	450	2012	300	2013	650
January	2012	450	2013	650	2014	700
February	2012	500	2013	600	2014	650
March	2012	400	2013	500	2014	550
April	2012	350	2013	450	2014	450
May	2012	350	2013	450	2014	450

According to the IPA, the PUA provides that it is the duty of the Procurement Administrator, in consultation with Staff, ComEd, and AIC, 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. The IPA states that standard wholesale products to be procured through the RFP could be settled physically or financially. In both cases, the IPA indicates that ComEd and AIC would contract to purchase or hedge specific quantities of energy at fixed prices.

In the case of financial settlement, the IPA says ComEd or AIC 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. The IPA claims financial contracts are generally referred to as “contracts for differences” ("CFD"). The swap contracts with ExGen and Ameren Energy Marketing, the IPA avers, are examples of a financially-settled contract.

In the case of physical settlement, the IPA indicates that contracting parties would transact through PJM or MISO. In this case, the IPA says both parties must be PJM or MISO members in good standing. The IPA states that ComEd or AIC and the seller would execute an agreement, under which the seller transfers energy to ComEd via a PJM e-Schedule or to AIC via a MISO process. According to the IPA, ComEd or AIC would then directly pay the seller the agreed-upon fixed contract price for the specified amount of energy.

The IPA believes that the choice between settling physically and financially does not affect service reliability. According to the IPA, whether the products settle physically or financially, PJM and MISO will still dispatch the system in such a way to ensure that customers' requirements are met. The IPA asserts that 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. According to the IPA, physical contracts are lower risk in the event of supplier default. The IPA says exposure of a supplier under a CFD is limited only by the PJM energy price cap of $999/MWh. While it would be very rare for prices for a sustained period to be at or near the energy price cap, the IPA states that a primary value of a hedge is to protect against such occurrences. In the IPA's view, 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 IPA says the 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. The IPA adds that any default costs would be spread over PJM. In the event of a default under a CFD, the IPA indicates that 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, the IPA claims it is not clear that there are adequate credit provisions to equalize this risk; therefore the IPA believes the physical contract is of lower risk for customers.

According to the IPA, physical contracts also reduce ComEd credit requirements and overall credit costs. Under a financial contract, the IPA says ComEd would be considered by PJM to be buying all load in the spot market and would have to provide credit for all volumes. Under a physical contract, the IPA indicates that the supplier is responsible to provide credit for all volumes. While the credit cost is not eliminated, the IPA believes 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.

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 Commodity Futures Trading Commission ("CFTC") to regulate derivatives (including financial swaps) and enforce position limits, margin requirements, and reporting requirements. According to the IPA, such changes have the potential to increase costs for AIC, its suppliers, and customers. The IPA states that 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. Also uncertain, the IPA says, is whether AIC will be partially or completely exempt from the rule making outcome since AIC may be viewed as an end user and not a speculator. In summary and in light of the information currently available, the IPA recommends replacing financial swaps for the spring 2011 procurement event with those that settle physically within MISO. The IPA believes this would appear to be the most prudent course of action until the rule making process is better understood. The IPA will monitor the rule making process and recommend a course of action for procurement events beyond spring 2011 as the outcome of the current rule making process becomes clearer.

The IPA recommends consideration of the purchase of EEAR for the ComEd and AIC portfolios. According to the IPA, the purpose of this is twofold – first, to establish whether energy efficiency can be cost competitive with more traditional resources; and second, to establish whether additional benefits such as price stability can be gained through expansion in the type of resource products placed into the portfolio. The IPA believes that the appropriate sources for EEAR bids would be programs that are evaluated in a manner equivalent to the existing EEPS programs offered to eligible retail customers in the ComEd and AIC service regions. The IPA notes that the results of the EEPS programs have been factored into the ComEd and AIC load forecasts in a manner similar to that of other pre-existing supply contracts for the past two cycles. Additionally, the IPA indicates that the EEPS programs are in their third year of operation under an evaluation and oversight regime supervised by the Commission. These two factors lead the IPA to determine that resources provided by the EEPS are reliable. The IPA plans to limit its procurement of utility-administered resources to those resources that are not required to meet the EEPS program requirements.

The IPA proposes that EEAR assets should only be procured when the cost of the EEAR is less than the combined cost of the energy swaps, capacity, and renewable energy resource contracts held by ComEd or AIC for the contract period offered by the EEAR provider. As such, the IPA says the EEAR contracts should be considered after the spring 2011 procurement events. The IPA asserts that contracts would be secured through direct negotiation between the IPA and ComEd or AIC subject to oversight and authorization by the Commission. If EEAR assets are not cost competitive, then the IPA indicates no contracts will be executed. In order to assure valid results in an EEAR procurement, the IPA recommends holding workshops during the fall of 2010 to establish the scope and nature of the EEAR event with the input of interested parties.

The IPA states that upon Commission approval of the Plan, ComEd will utilize the PJM-administered day-ahead and real-time energy markets to balance its loads. On a daily basis, the IPA says ComEd will report to PJM its estimate of its total load requirements for the following day. ComEd, the IPA reports, 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. The IPA indicates that 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, the IPA states that 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; the IPA says 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, the IPA says PJM will credit ComEd with the difference at the real-time price.

Upon Commission approval of the Plan, the IPA says AIC will enter into financial swap transactions to hedge the energy price risk of the portfolio. The IPA indicates that 100% of the energy required to supply the load included in the Plan will be purchased in the MISO energy markets. According to the IPA, AIC 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. The IPA indicates that 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. The IPA states that MISO charges, including Revenue Neutrality Uplift and Revenue Sufficiency Guarantee payments will also apply.

B. Capacity Resources

According to the IPA, under the Reliability Pricing Model ("RPM") program approved by the Federal Energy Regulatory Commission ("FERC") and administered by PJM, ComEd is able to purchase capacity directly from PJM-administered markets. The IPA reports that the RPM capacity prices for the June 2011 through May 2014 period have already been determined through a competitive bid process administered by PJM, so the IPA believes direct procurement from PJM results in a reasonable approach to procuring capacity for these customers. Furthermore, the IPA asserts that 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.

The IPA states that 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, the IPA explains that PJM may return excess capacity credits to the utility. These credits, the IPA avers, represent MW units of capacity and are not in the form of cash or cash equivalents. While these credits can not be used to offset capacity payments to PJM, the IPA says 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. The IPA notes that PJM has a bulletin board where such excess capacity credits can be made available for sale.

With regard to AIC's capacity resources, the IPA states that Module E of MISO's Open Access Transmission, Energy and Operating Reserve Markets Tariff addresses resource adequacy. The IPA says Module E requires AIC to hold the lower of the reserve requirement as specified by an annual planning process undertaken by MISO or the requirement of the relevant state regulatory authority. Module E, along with the associated business practice manual, also requires AIC to provide an annual forecast of monthly loads adjusted for transmission losses and subsequently confirm on a month-ahead basis that AIC has enough PRCs to meet or exceed its resource adequacy requirement (the monthly peak load forecast plus its planning reserve margin).

The IPA makes note that significant changes to the MISO resource adequacy construct are currently being discussed at MISO. In a September 2, 2010 presentation to the Supply Adequacy Working Group, the IPA says MISO laid out the enhancements that it is currently considering for Module E. According to the IPA, these enhancements include moving to a three- to five-year forward looking construct and shifting to annual or seasonal compliance rather than the current monthly compliance. The presentation also includes a timeline which shows opportunities for stakeholder input, MISO finalizing their proposal in mid-October, tariff changes being filed at FERC on December 8, 2010, and an effective date for the changes of June 1, 2012. Given the uncertainty around this process, the IPA claims it may not be possible to define the capacity product required to comply with these future requirements until at least sometime after the December 8 filing and possibly not unit such time as FERC has issued its final order. With this in mind, the IPA will only procure the capacity resources required to fully comply with the MISO resource adequacy requirements for the 2011 planning year which are currently known and certain and not attempt to procure resources for any future years in which the MISO requirement is uncertain at this time.

For demonstration purposes, the IPA provides tables which utilize the reserve margin of 4.5% that has been effective for the planning year beginning in June 2010 through May 2011. The IPA indicates that the planning reserve margin beginning June 2011 has yet to be established and therefore the IPA recommends that the Commission authorize the Procurement Administrator, in consultation with the IPA, Staff, the Procurement Monitor, and AIC, to adjust the quantities of capacity to acquire to comply with the applicable planning reserve requirements. Furthermore, to the extent to which it is impractical or impossible for the Procurement Administrator to modify its capacity RFP to fully account for all applicable capacity requirements and planning reserve requirements, the IPA recommends that the Commission authorize AIC to make up the difference through one or more supplemental procurement processes. The IPA proposes that 100% of the monthly capacity requirements be acquired for the first planning year (June 2011 through May 2012). Under the IPA's proposal, some capacity was procured in 2010 for the 2012 planning year. Pursuant to the previous discussion regarding MISO changing its capacity construct, the IPA will not make any additional purchases in 2011 for the 2012 planning year. The IPA says this will result in a hedge of approximately 35% of the capacity requirement for the 2012 planning year (June 2012 through May 2013). The IPA indicates that no capacity will be procured for the third planning year (June 2013 through May 2014). The IPA says the Procurement Administrator will issue solicitations to lock-in fixed prices for fixed quantities of required capacity resources, using single-month, multi-month, and/or annual contracts during the period between June 2011 and May 2014, in whatever combinations are deemed appropriate by the procurement administrator, given the objectives described in this plan. The IPA adds that in 2009, MISO implemented significant penalties associated with a capacity deficiency event based on the cost of new entry. For the 2009 Planning

Year, the IPA indicates that the deficiency penalty was determined by MISO to be \$80/kW-month, \$90/kW-month for 2010, and \$95/kW-month for 2011.

C. Demand Response Resources

The IPA recommends meeting ComEd's and AIC's statutory obligation of procuring demand response as a free-standing obligation not related to the replacement of Capacity Resources. The IPA suggests procuring in the spring of 2011 Demand Response assets that meet the Act's definitions and are registered as qualifying capacity resources in the PJM RPM auction and as qualifying PRCs by MISO. Consistent with the Act, however, the IPA recommends limiting the procurement of Demand Response Resources to the extent that they meet cost effectiveness and source requirements. Finally, the IPA suggests that Demand Response Resources be secured for contract durations of between five and ten years.

D. Renewable Energy Resources

The IPA observes that Section 1-75(c) of the Illinois Power Agency Act ("IPA Act"), 20 ILCS 3855/1-1 et seq., 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, procured for each of the following years shall be generated from cost‑effective renewable energy resources . . . .

Section 1-10 of the IPA Act defines renewable energy resources as:

> "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, crops and untreated and unadulterated organic waste biomass, trees and tree trimmings, 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.

The IPA indicates that the statute establishes a methodology for calculating annual volumetric goals for the portfolio as well as establishing a Renewable Energy Resource Budget ("RERB") that serves as a maximum cost cap for meeting those goals. The IPA also indicates that 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. A table summarizing this information is reproduced below.

Delivery period	Minimum Percentage (Annual volume goal)	Maximum Cost Standard
2011-2012	6% of June 1, 2009 through May 31, 2010 eligible retail customer load	The greater of an additional 0.5% of the amount paid per kWh by those customers during the year ending May 31, 2010 or 2% of the amount paid per kWh by those customers during the year ending May 31, 2007
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 kWh by those customers during the year ending May 31, 2007 or the incremental amount per kWh 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 kWh by those customers during the year ending May 31, 2007 or the incremental amount per kWh paid for these resources in 2011
2014-2015	9% of June 1, 2012 through May 31, 2013 eligible retail customer load	No more than the greater of 2.015% of the amount paid per kWh by those customers during the year ending May 31, 2007 or the incremental amount per kWh paid for these resources in 2011
2015-2016	10% of June 1, 2013 through May 31, 2014 eligible retail customer load	No more than the greater of 2.015% of the amount paid per kWh by those customers during the year ending May 31, 2007 or the incremental amount per kWh paid for these resources in 2011

The statute requires the higher of two separate calculations to establish each planning year's RERB. The IPA states that annual RERBs resulting from the application of the statute's standards to the ComEd portfolio for planning years 2011-2012 are $77,176,270 and $67,143,329, respectively. The corresponding values for AIC are $30,180,309 and $26,204,037, respectively. The table below was derived from information contained in the Plan and summarizes the Renewable Portfolio Standard ("RPS") metrics and targets for the 2011-2012 planning period for ComEd and AIC.

Renewable Portfolio Standard Metrics and Targets for 2011-2012

	ComEd	AIC
RPS Volume Target (MWh)	2,117,054	952,145
Renewable Energy Resource Budget (RERB)	77,176,270	30,180,309
Average Price per Renewable Unit ($/MWh)	$36.45	$31.70
Estimated Consumers Covered by RERB	3,742,263	1,169,723
Estimated Annual RPS Cost/Consumer	$20.62	$25.80

The IPA plans to direct the Procurement Administrator to continue to establish benchmark REC prices (as in the two prior Plans), and to reject bids priced above the benchmarks. The IPA states that benchmarks will be set at levels that consider relevant market prices and the economic development benefits of in-state resources. According to the IPA, 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. The IPA adds that 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 within the State of Illinois, then from facilities located in states adjacent to Illinois, then from facilities located elsewhere. The IPA proposes that each agreement for the acquisition of a REC to have a specified term and for all RECs to be retired in compliance with Section 1-75(c)(4) of the IPA Act.

The IPA states that the acquisition of RECs in amounts equal to the statutory requirement ensures compliance with such statutes. The IPA also says that the 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 ("NARR") will be utilized to independently verify the location of generation, resource type, and month and year of generation. According to the IPA, GATS tracks generation attributes and the ownerships of the attributes as they are traded or used to meet RPS and other programs, typically for generators whose energy is settled in the PJM market or whose facility is located in the PJM footprint. The IPA adds that 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. The IPA relates that NARR tracks renewable energy generation from facilities typically outside of the M-RETS and PJM footprints.

E. Incremental Procurement Events

The IPA proposes that optional incremental procurements of up to an additional 10% of projected portfolio requirements be allowed under certain circumstances. First, the IPA says the incremental procurements could seek to secure volumes for only those months that have not achieved a full 100% subscription level. Second, under the IPA's plan the optional procurements would be triggered only when market indices demonstrate that prices for energy supply contracts for the targets months are below the average weighted price of fixed price contracts already secured by ComEd or AIC for those months. Third, the IPA says the optional procurements would be limited to participation by bidders qualified in and operate only under the terms and conditions agreed to in the spring 2011 solicitation. Lastly, the IPA proposes for such procurement events to only occur, and the results only accepted, with the authorization of the Commission.

F. Transmission Service; Ancillary Services; Auction Revenue Rights

According to the IPA, in addition to the acquisition of power and energy related products, 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. The IPA explains that 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. The IPA indicates that PJM operates an ancillary services market to provide regulation service and operating reserve service (both spinning and supplemental) reserves. ComEd, the IPA says, will secure these required services through the PJM ancillary services market. Additionally, ComEd may be allocated certain financial transmission/auction revenue rights ("ARR"). ARRs are not a power and energy resource. The IPA indicates, however, that 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 its customers). As part of the 2010-11 ARR allocation process at PJM, the IPA says ComEd received a set of ARR entitlements and was awarded ARRs for that planning year.

For future planning years, the IPA expects ComEd to continue to actively participate in the PJM ARR nomination and allocation process and to seek to nominate those ARRs with an expected positive value. The IPA says ComEd recognizes it may not be allocated all of the ARRs requested and it may elect certain ARRs which ultimately do not have a positive value. The IPA states that ComEd will retain the allocated ARRs and receive associated credits for its customers. According to the IPA, 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 - Purchased Electricity.

Similarly, AIC is obligated by the MISO tariff to acquire certain transmission service related products and services to effectuate delivery of power and energy to the applicable loads. The IPA says these services include network integrated transmission service ("NITS") and ancillary services. The IPA states that NITS is described in Section III of Module B to the MISO tariff. According to the IPA, AIC utilizes such NITS to reliably deliver capacity and energy from its network resources to its network loads – namely its native load obligations. The MISO tariff, the IPA avers, 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. The IPA believes AIC has acquired the necessary NITS in accordance with the tariff. The IPA says the cost for this service is established through the applicable MISO tariff schedules. With regard ARRs, the nomination and subsequent allocation of such ARR to AIC generally serves to reduce the cost of congestion borne by AIC and ultimately by its customers. According to the IPA, as part of the 2010 ARR allocation process at MISO, AIC received a set of ARR entitlements and was awarded ARRs for the 2010 planning year.

For future planning years, the IPA recommends that AIC continue to actively participate in the MISO ARR nomination and allocation process and seek to nominate those ARRs with an expected positive value. Like ComEd, the IPA says AIC recognizes it may not be allocated all of the ARRs requested and it may be required by MISO to accept certain ARRs which do not have an expected positive value. The IPA suggests that AIC retain the allocated ARRs and receive associated credits for its customers. The IPA also believes AIC 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 Ameren Transmission-Illinois balancing authority, AIC may attempt to reallocate the applicable ARRs from its historical resource points to those which align more closely with the designated energy resource delivery point.

G. Portfolio Rebalancing

Section 16-115.5(b)(4) of the PUA requires that the IPA provide the criteria for portfolio rebalancing in the event of significant shifts in load. In the event that ComEd's or AIC's annual forecast increases above the High Forecast or decreases below the Low Forecast during the active delivery year of an approved Plan, the IPA wants ComEd or AIC to promptly notify the IPA. The IPA plans to subsequently convene a meeting with ComEd or AIC, the Commission, 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. The IPA asserts that over the term of this Plan, the most significant driver of load shifting levels is customer switching.

H. Contingencies

The IPA has developed a 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 IPA asserts that the proposed plan is based on the contingency plan as specified in the IPA Act and Section 16-111.5(e)(5)(i) of the Act.

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, the IPA proposes that ComEd immediately notify it, Staff, and the Procurement Administrator that another procurement event must be administered. The IPA proposes for the Procurement Administrator to execute a procurement event to replace the same products and amounts as that initially approved by the Commission in the Plan. The IPA proposes that Staff and the Procurement Monitor 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. Under the IPA's proposal, this substitute plan would continue to seek energy-only standard-block products. The IPA says all ancillary services, 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, the IPA plans for all electric power and energy to be procured by ComEd through PJM-administered markets. 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, the IPA proposes that ComEd procure the required power and energy directly from the PJM administered markets. The IPA says this procurement would include day ahead and/or real-time energy, capacity, and ancillary services. Regardless of the amount in question, should a required product not be available directly through the PJM administered markets, the IPA says it shall be procured through the wholesale markets.

In the event that the Commission rejects the results of the initial procurement event or the initial procurement event results in under subscription, the IPA proposes that a meeting of the Procurement Administrator, the Procurement Monitor, and Staff occur within 10 calendar days to assess the potential causes and to consider what remedies, if any, could be put in place to either address the Commission's concerns or would result in full subscription to the load. The IPA says that if revisions to the procurement event are identified that would likely either address the Commission'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 IPA proposes for the new procurement event to be executed by the Procurement Administrator within 90 calendar days of the date that the initial procurement process is deemed to have failed.

In all cases where the factors are such, either for an interim period or otherwise, that there would be insufficient power and energy to serve the required load, the IPA proposes that ComEd procure the required power and energy requirements for the eligible load through the PJM-administered markets. The IPA says direct procurement activities would 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, the IPA says ComEd will purchase that product through the wholesale market.

According to the IPA, AIC's Rider PER (Purchased Energy Recovery) (Electric Service Schedule Ill.CC. No. 18) will serve as the basis of AIC's Contingency Procurement Plan.

VII. DISPUTED ISSUES AND COMMISSION CONCLUSIONS

A. Energy Efficiency Measures

As discussed above, the IPA proposes to allow energy efficiency from existing EEPS programs administered by ComEd and AIC to be treated as an energy supply resource. The IPA states that the price for the products would be negotiated after the closing of the spring 2011 solicitations for the more traditional physical and financial swap products. The IPA explains that the combined costs of traditional energy, capacity, and renewable energy assets within the IPA portfolio after the spring 2011 procurement events will be used to develop a cost-effectiveness benchmark for the energy efficiency procurements. The IPA will not procure resources that are needed to meet the EEPS.

1. ComEd Position

ComEd contends that the IPA has no legal authority under the PUA to procure energy efficiency measures. According to ComEd, the appropriate forum for the consideration of the procurement of energy efficiency measures are the proceedings and processes set up under the statutorily required EEPS programs. ComEd insists that this aspect of the Plan is unlawful and must be rejected by the Commission.

Section 8-103 of the PUA addresses the procurement of energy efficiency measures. ComEd relates that this Section both specifies annual target amounts of energy efficiency to be obtained and establishes caps on the amount that these measures can raise customers' rates. Section 8-103, ComEd adds, also makes clear that utilities are responsible for overseeing the design, development, and filing of energy efficiency plans with the Commission, and that each utility and the Illinois Department of Commerce and Economic Opportunity ("DCEO") share the responsibility to implement the approved measures. ComEd interprets the PUA as providing for no direct role for the IPA in the design, development, or implementation of the energy efficiency plan or measures. According to ComEd, the IPA can only obtain responsibility for implementing energy efficiency measures and procuring resources to meet energy efficiency standards if a utility fails to meet applicable efficiency standards over a three-year period, as set forth in Section 8-103(i).

ComEd reports that it filed its energy efficiency plan for the June 2011 through May 2014 period with the Commission on October 1, 2010, initiating Docket No. 10-0570. In ComEd's view, that is the sole proceeding in which to explore what energy efficiency measures are to be procured within the statutorily-prescribed target and cap amounts. This process, ComEd notes, does not exclude the IPA. In developing its proposed plan, ComEd sought and received input from a broad group of stakeholders, including the IPA. The IPA, ComEd suggests, is also free to participate in the Commission proceeding that will review ComEd's efficiency plan.

Instead of complying with the statutory framework and expressing its views in the efficiency plan docket, ComEd complains that the IPA seeks the ability to procure energy efficiency measures separately, purportedly pursuant to Section 16-111.5 of the PUA. Section 16-111.5, ComEd contends, confers no authority on the IPA to procure energy efficiency measures. According to ComEd, the only mention of energy efficiency measures therein is in subsection 16-111.5(b)(2), which requires the Plan to consider the impact of energy efficiency programs on the supply needs of the utility. Moreover, ComEd states that once those supply needs are determined, the Plan is required to propose the mix and selection of "standard wholesale products" for which contracts will be executed. ComEd asserts that the only standard wholesale products which the PUA specifically authorizes the IPA to consider are energy, capacity, and ancillary services. ComEd argues that not only is the proposed procurement of energy efficiency measures not legally authorized, the energy efficiency measures also are not “standard wholesale products.”

ComEd notes that the IPA points to general statements in statutory preambles in support of portions of its petition. But such preambles, ComEd contends, are statements of general policy and do not authorize any action. (Monarch Gas Co. v. Illinois Commerce Commission, 261 Ill.App.3d 94 (5th Dist. 1994), appeal denied, 157 Ill.2d 505; Governor's Office of Consumer Services v. Illinois Commerce Commission, 220 Ill.App.3d 68 (3rd Dist. 1991)) ComEd also asserts that the IPA Act preamble does not authorize the IPA to procure any specific resources, let alone the efficiency and demand response resources it seeks authority to purchase. The same General Assembly that enacted this preamble, ComEd contends, also passed the strict customer protections limiting the cost of energy efficiency measures and provided that utilities, not the IPA, were to propose plans for the procurement of efficiency resources.

According to ComEd, the legislative history confirms that the General Assembly deliberately excluded energy efficiency measures from the scope of the IPA-managed procurements. ComEd observes that the legislature revised the PUA in 2009 to require that a procurement Plan include capacity related to demand response resources. (P.A. 95-1027 (eff. 6-1-09)) That the General Assembly specifically listed demand response resources as a product that the IPA could procure if applicable requirements were met, but did not include energy efficiency measures, ComEd contends, is a clear indication that the General Assembly did not intend to authorize the IPA to procure energy efficiency products. ComEd can not accept that the General Assembly would have written this specific requirement into the law if it intended the IPA to have the authority to procure efficiency products regardless of the three-year requirement. In ComEd's view, the exclusion of energy efficiency measures from the list of standard wholesale products that the IPA can procure under Section 16-111.5 is intentional and binding.

Not only does ComEd believe the IPA’s proposal is unlawfully beyond its authority, ComEd suggests it also poses other risks to the statutory scheme. ComEd states that Section 8-103(d) of the PUA caps the amount by which customers’ rates can increase due to the costs of energy efficiency measures. The General Assembly, ComEd indicates, provided that the Commission is to review those caps and report back by June 30, 2011 whether the caps unduly constrain the procurement of energy efficiency measures. ComEd is convinced that the legislature would not have so carefully limited the amount of energy efficiency measures to be procured and required a Commission study of the issue prior to authorizing the procurement of any additional energy efficiency measures in one section of the PUA, only to provide uncapped authority to the IPA to procure energy efficiency measures under a different section of the PUA. According to ComEd, the legislative intent to exclude energy efficiency measures is consistent with the industry understanding of what are standard wholesale products, which do not include energy efficiency measures in ComEd's opinion.

ComEd contends that another, but related, reason the law does not allow the IPA to procure energy efficiency measures, and instead provides for a separate process for the development of energy efficiency programs, relates to the fact that energy efficiency measures involve different risks than standard wholesale products. ComEd states that block energy products involve a predetermined and fixed amount of energy supply. The amount and timing of energy to be avoided by the procurement of an energy efficiency measure, however, is unknown at the time the decision is made to procure it. This uncertainty, ComEd asserts, is driven by many factors, including uncertain local climate conditions, the uncertainty regarding the number of customers who actually enroll in the energy efficiency program, the uncertainty regarding the effectiveness of the energy efficiency measure in avoiding energy usage, and the risk that performance does not meet expectations due to program design or implementation flaws.

In response to the NRDC's support for the IPA's EEAR proposal, ComEd notes that Section 16-111.5(b)(iv) of the PUA requires that the Plan include 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. Consistent with these statutory requirements, ComEd also notes that Section 16-111.5(b)(v) requires the Plan to include the proposed term structures for each wholesale product type included in the proposed portfolio of products. ComEd claims that NRDC's argument that the use of standard wholesale products is not required flies in the face of the above-described specific statutory language.

2. AIC Position

AIC argues that neither the PUA nor the IPA Act permits energy efficiency programs to be considered as part of the supply portfolio mix and their inclusion in the portfolio mix should be rejected. AIC claims that energy efficiency programs are beyond the scope of products the IPA is allowed to procure on behalf of the utilities as detailed in Section 16-111.5 of the PUA. According to AIC, there is nothing about the IPA presentation that would affirm the use of energy efficiency programs other than their request for them to be considered. As the IPA Act requires the procurement plans to be in compliance with Section 16-111.5 of the PUA, and energy efficiency programs are not included in the category of products allowed under Section 16-111.5, AIC believes that their inclusion violates the law.

The procurement plan, AIC states, calls for a mix and selection of "standard wholesale products" for which contracts will be executed. According to AIC, the only standard wholesale products which the PUA specifically authorizes the IPA to consider are energy, capacity, and ancillary services. AIC insists that energy efficiency programs are not "standard wholesale products." "Standard wholesale products," AIC claims, refer to standardized products sold using a standardized contract that is only differentiated by price. AIC indicates that Section 16-111.5(c)(1)(vii) of the PUA allows the Procurement Administrator to negotiate with the bidders for standard wholesale products only as to the price of the product and only for 24 hours. AIC states that

Section 16-111.5(e)(2) requires the use of a standard contract form so that bids may be evaluated solely on the basis of price. AIC finds it notable that the IPA is silent as to how the procurement of energy efficiency programs might comply with those requirements.

In addition to arguing that the IPA proposal is outside of the scope of the PUA, AIC complains that the IPA is vague in several key areas of detail and therefore lacks clear direction as to how such a proposal would be implemented. First, AIC observes that the IPA does not identify the quantity of energy efficiency programs it desires to procure and for what term. The IPA states that a pricing benchmark will be developed after the spring 2011 solicitation, yet it is not clear to AIC whether the IPA intends to seek energy efficiency programs for the 2011 planning year or later. AIC notes that the IPA proposal for the spring 2011 solicitation will hedge 100% of the energy requirements for the 2011 planning year (110% of July/August on peak). So if the IPA intends to pursue energy efficiency programs starting in the 2011 planning year, AIC states that any quantities successfully implemented would create an "over-hedge" when compared to the forecasted requirements of the load and the IPA recommended hedge level. AIC expresses concern that this over-hedge could result in additional costs to be borne by customers. If the IPA intends to pursue energy efficiency programs as an offset to supply starting in 2012 or later, AIC believes that the IPA should specify the quantity desired and make a corresponding offset to the amount of energy hedges specified in the Plan. Second, AIC contends that the IPA has not specified the criteria by which it will be determined that energy efficiency programs are cheaper than energy hedges. The IPA suggests that benchmarks will be developed after the spring 2011 solicitation for energy hedges, but AIC observes that the IPA makes no mention of the fact that energy efficiency program impacts are variable in nature while energy hedges are block in nature. In addition, AIC complains that no mention is made of what method would be used to account for this difference and who would be responsible for its development. Third, AIC notes that the IPA intends to limit its procurement of utility-administered resources to those that are not required to meet the EEPS. AIC points out, however, that no mention is made of what steps the IPA would take to ensure that double counting does not occur between the energy efficiency programs associated with the EEPS and those associated with the Plan.

3. Staff Position

Staff objects to the EEAR proposal for several reasons. Staff's first argument is that the proposal exceeds the IPA's authority and is contrary to the PUA and IPA Act. Staff states that the purchase of EEAR products is beyond the scope of products the IPA is allowed to procure on behalf of the utilities pursuant to Section 16-111.5 of the PUA. Pursuant to Section 16-111.5(d)(2), Staff insists that the portfolio of products to be included in the IPA's Plan is limited to demand response products and power and energy products. Staff complains further that the Plan fails to specify the quantity and term of the EEAR to be procured, as required by Sections 16-111.5(b)(3)(iv) and (v), respectively. Even if the quantity and term were specified, Staff believes it is difficult to see how EEAR can be considered "a standard wholesale product" as required by

16‑111.5(b)(3)(iv) of the PUA. With such concerns in mind, Staff observes that Section 1-75(a) of the IPA Act provides that procurement Plans are to be in compliance with Section 16-111.5. In addition, Staff claims that the purchase of EEAR would be subject to the spending limits imposed by Section 8-103(d), which the Plan ignores.

In Staff's view, the process of negotiation between the IPA and the utilities, as described in the EEAR proposal, seems inconsistent with the provisions of Sections 16‑111.5(c), (e), (f), and (g), especially (e)(4), which require a "competitive procurement process" where a "procurement administrator shall design and issue a request for proposals to supply electricity in accordance with each utility's procurement plan, as approved by the Commission. The request for proposals shall set forth a procedure for sealed, binding commitment bidding with pay‑as‑bid settlement, and provision for selection of bids on the basis of price." According to Staff, Section 16‑111.5 makes it clear that supply bids are to be selected solely on the basis of price. It is not clear to Staff what price to use in the context of EEAR. Staff complains that the IPA fails to explain how it would decide when EEAR is less expensive than an energy supply resource. Moreover, Staff asserts that EEAR or energy efficiency products are not listed as a product that the IPA is allowed to purchase.

Another area of concern for Staff relates to the IPA's apparent presumption that the utilities' efficiency programs are far more mature and reliable than what Staff is willing to concede. While the first three-year plans are currently in their third year of operation, Staff notes that evaluations have been completed for only one of the three years. Staff also states that since Section 8-103 of the PUA does not include any penalties for poor first-year performance, these evaluations were not the subject of a docketed investigation and were not subjected to as rigorous a review as Staff intends to perform on the second and third year evaluations.

Staff takes exception to particular arguments raised by NRDC as well. Staff contends that NRDC's argument that the budget cap imposed by Section 8-103 of the PUA only limits the utilities spending and not the IPA's or any other entities is based upon a tortured reading of the IPA Act and PUA. The NRDC's position, Staff reports, is that the cap only applies to utilities and no other entities. In response, Staff states that a plain reading of the statute shows that is simply not the case. Under Section 8-103(e), Staff relates that a utility is allowed to recover through its tariffs prudent and reasonably incurred costs for energy efficiency measures and demand response measures. The costs which the utilities are allowed to pass through their tariffs includes both the utilities' energy efficiency and demand response measures costs and the DCEO energy efficiency and demand response measures costs. In addition, Staff points out that under the statute both the utilities and DCEO's energy efficiency measures costs are subject to the cap imposed by Section 8-103(d). Staff therefore believes that it is simply wrong for NRDC to claim that the cap only applies to utilities and does not apply to any other entities when it clearly applies to DCEO. NRDC also errs, in Staff's opinion, in its argument that the budget cap imposed by the legislature under Section 8-103 is intended to protect utilities rather than ratepayers. If the legislature had a concern with the impact of energy efficiency measures on utilities' budgets and not ratepayers' budgets, Staff avers that it would not have imposed a budget cap that takes into account the impact of those measures on retail customers' bills.

4. NRDC Position

NRDC observes that Section 8-103 clearly sets out a mandate for electric utilities to achieve minimum energy efficiency goals, and limits the utilities' budgets for achieving those goals. NRDC notes further that there are penalties for failure to meet the goals. The consequence for a persistent failure to meet the EEPS is that the authority to administer the programs will be shifted to the IPA. NRDC does not view the statute as prohibiting the utilities, or any other entity, from procuring additional cost effective energy efficiency over and above that prescribed by the minimum savings goals. NRDC asserts that utilities can exceed the targets and recover the costs of doing so within the cap. NRDC also contends that the statute does not impose a budget cap on any entity other than the utilities for capturing cost effective energy savings to lower the costs of energy service for Illinois customers.

According to NRDC, Section 16-111.5 of the PUA contains no explicit language limiting the Plan to "standard wholesale products." To impose that limitation, NRDC asserts, is to ignore other language that assumes a broader range of resource choices are available to allow the IPA to design a balanced portfolio. NRDC suggests that the utilities' reading renders meaningless the explicit language of Section 16-111.5(d)(4) which allows the Commission to approve a Plan only if it determines that it will "ensure adequate, reliable, affordable, efficient, and environmentally sustainable electric service at the lowest total cost over time." NRDC contends that the inclusion of the word "efficient" and the phrase "at the lowest total cost over time," in the foregoing criteria are inconsistent with a reading of the statute that prohibits inclusion of energy efficiency.

NRDC adds that the utilities and Staff also ignore language in Section 16-111.5(b)(vi) which requires the Plan to assess "timeframes for securing products or services." NRDC maintains that this language acknowledges that services such as energy efficiency programs can substitute for supply-side resources. NRDC notes further that the same Section requires the Plan to "identify alternatives for those portfolio measures that are identified as having significant price risk," and does not make any attempt to limit those alternatives to supply-side alternatives.

As evidence that the General Assembly meant to exclude energy efficiency, NRDC reports that ComEd offers the view of one person, Scott G. Fisher, to describe the "industry understanding of what wholesale products are." NRDC responds that one person's view of the "industry understanding" of the definition of standard wholesale products is not dispositive, nor does it create a prohibition on the inclusion of energy efficiency that the General Assembly did not impose.

NRDC observes that all parties acknowledge that the IPA can procure demand response products as part of its portfolio. In NRDC's view, it stands to reason then that the IPA can also include energy efficiency measures since energy efficiency is a subset of demand response. The definition of "demand response," NRDC notes, is found in the IPA Act at Section 1-10; the same Section includes the definition of "energy efficiency." NRDC believes that there is an important reason for having these two resources defined separately. NRDC contends that shifting demand in time is not the equivalent of saving energy, and therefore demand response programs can not substitute for energy efficiency programs for the purpose of meeting energy savings goals. NRDC insists, however, that energy efficiency measures, by reducing the total amount of power needed to perform a task, often produce significant reductions in peak electricity demand, and therefore energy efficiency can be a subset of demand response resources under the Plan.

5. ELPC Position

In its Brief on Exceptions, ELPC voices support for the IPA's EEAR proposal. ELPC acknowledges that the IPA Act does not expressly authorize the IPA to acquire energy efficiency through the Plan, but contends that the IPA Act provisions that do reference energy efficiency, when considered in their totality, indicate that the legislature did envision the IPA procuring efficiency. ELPC urges the Commission to defer to the IPA's judgment on this issue and to not attempt to micromanage the IPA. Given the IPA’s experience and expertise, ELPC believes that it is safe to assume the IPA will seek a reasonable quantity of efficiency that does not result in over-procurement.

In response to the arguments of AIC and ComEd that the IPA lacks legal authority for its EEAR proposal, ELPC warns the Commission that the utilities have an ulterior motive here. ELPC reminds the Commission that the utilities have unregulated affiliates that compete in the procurement process. According to ELPC, they therefore want to protect their sales of power to the IPA. Moreover, ELPC continues, if third parties bid in to the procurement process and can deliver energy efficiency at lower costs than the utility, this raises questions about the prudency of the utility and its ability to run optimal programs.

6. IPA Position

The IPA disputes the assertions of ComEd, AIC, and Staff regarding energy efficiency. Specifically, the IPA notes that the three argue that (1) the IPA has no authority under the PUA to procure energy efficiency measures, and (2) the PUA only permits the IPA to procure a mix of “standard wholesale products.” According to the IPA, however, Section 8-103 of the PUA specifically authorizes it to assume responsibility for implementing energy efficiency measures when ComEd or AIC fail to meet the applicable efficiency standards set forth in Section 8-103. While the EEPS programs maintained under Section 8-103 are independent from EEAR as proposed in the Plan, the IPA contends that there is a clear mandate from the legislature authorizing the IPA to procure and promote energy efficiency.

In defense of its position, the IPA asserts that past authorized the use of “swap contracts” for meeting AIC’s energy supply requirements is further evidence that “standard wholesale products” does not necessarily require a supplier to provide energy. Given the AIC market conditions, the IPA relates that past Plans procured financials swaps in lieu of physical delivery of energy. Under such Plans, AIC pays a fixed price to its supplier in exchange for receiving a floating price (MISO LMPs) from the supplier. Like the use of financial swaps to satisfy AIC’s eligible retail customers’ needs, the IPA asserts that Section 16-111.5 of the PUA does not bar it from purchasing EEAR. The IPA contends that Section 1-5 of the IPA Act, together with Section 1-125, make it clear that the IPA is required to promote energy efficiency measures in its Plans, and there is no provision in Section 16-111.5 of the Act that precludes the IPA’s proposal.

In response to the argument that EEAR would be precluded because the amount and timing of energy to be avoided by the procurement of an energy efficiency measure are unknown at the time the decision is made to procure it, the IPA relies on Section 8-103(f). The IPA states that Section 8-103 requires that a utility, when proposing energy efficiency programs to meet the EEPS, demonstrate that the EEPS program is cost effective. The IPA indicates that this requires that the utility produce information on the cost of its program, and the demand anticipated by EEPS proposals. In the IPA's view, the claim that the IPA could not identify an expected demand for EEAR is not true.

The IPA concedes that any energy efficiency program purchased as an alternative resource must be less than the energy procured through the standard procurement events. The IPA claims the only way for it to test this market is by hosting a competitive bid procurement. The IPA adds that it intends to conduct workshops in the fall 2010 to gather more information on the market for energy efficiency as an alternative resource. In the meantime, the IPA believes the Commission should authorize it to conduct a procurement event for energy efficiency as an alternative resource, consistent with the mandate set forth in the IPA Act.

7. AG Position

In its Brief on Exceptions, the AG argues in support of the IPA's inclusion of energy efficiency as a resource in the Plan. The AG maintains that the law, when read in its entirety, demonstrates that the IPA has broad authority to purchase energy efficiency as well as other resources to meet electric supply. The AG states further that one canon of statutory construction provides that, “If the language of a statute is susceptible to two constructions, one of which will carry out its purpose and another which will defeat it, the statute will receive the former construction.” (Harvel v. City of Johnston City, 146 Ill.2d 277, 284, (1992); County of Kankakee v. Illinois Pollution Control Board, 396 Ill.App.3d 1000 (2009)) In reviewing the IPA’s Plan, the AG contends that the Commission should only assess whether the Plan is reasonable, is consistent with the statute, and furthers the legislative intent evidenced in the statute.

In the context of energy efficiency, the AG insists that any conclusion that the IPA lacks authority to procure energy efficiency applies the IPA Act too narrowly and fails to defer to the IPA's interpretation of its own enabling statute. Such a conclusion, the AG continues, ignores key provisions that grant the IPA significant latitude in developing a Plan and in carrying out its duties to procure electricity for Illinois consumers. The AG cites subsections (a)(1), (2), and (9) of Section 1-20 of the IPA Act and Section 16-111.5(b)(3)(v) and (vi) of the PUA as support for the IPA having authority to include its EEAR proposal in the Plan. Taken as a whole, the AG believes that the law supports its position. The AG acknowledges that the PUA addresses utility energy efficiency obligations in Section 8-103, but contends that the PUA does not preempt or otherwise cancel the energy efficiency opportunities available to the IPA under the IPA Act.

8. Commission Conclusion

The IPA discusses its EEAR proposal as it pertains to AIC at pages 32-33 of the Plan and as it pertains to ComEd at page 49 of the Plan. The proposal appears to be the same as it applies to both utilities. Because the least expensive electricity is frequently the electricity never generated, the Commission is intrigued by the notion of procuring electricity in this way. The Commission is concerned, however, that the EEAR proposal exceeds the IPA's statutory authority. AIC, ComEd, and Staff argue that neither the IPA Act nor PUA authorize the IPA to seek energy efficiency as a resource.

The IPA Act contains only a few references to energy efficiency, none of which expressly grant the IPA authority to procure it as part of any procurement Plan. Section 1-5 of the IPA Act contains the legislative declarations and findings. Subsection (1) of Section 1-5 provides, "The health, welfare, and prosperity of all Illinois citizens require the provision of adequate, reliable, affordable, efficient, and environmentally sustainable electric service at the lowest total cost over time, taking into account any benefits of price stability." Subsection (7) contains the finding that, "Energy efficiency, demand‑response measures, and renewable energy are resources currently underused in Illinois." Section 1-10 of the IPA Act defines "energy efficiency" as "measures that reduce the amount of electricity or natural gas required to achieve a given end use." The final specific reference to energy efficiency in the IPA Act is in Section 1-125, which describes the annual report that the IPA must provide to the governor and legislature. Under subsection (3) of Section 1-125, the report must include the "quantity, price, and rate impact of all energy efficiency and demand response measures purchased for electric utilities."

Similarly, the PUA contains no express language authorizing the IPA to acquire energy efficiency through the Plan. Rather, the PUA provides through Section 8-103 that electric utilities shall implement energy efficiency measures through plans approved by the Commission. Only if a utility fails to meet for three years the applicable annual energy savings goal set forth in the statute does Section 8-103 grant the IPA an official role in the energy efficiency plans. After three years of missed goals, subsection (i) of

Section 8-103 provides that the responsibility for implementing the energy efficiency measures shall transfer to the IPA.

In contrast to the lack of clear authorization to implement the EEAR proposal, the PUA and IPA Act expressly authorize the procurement of demand response and renewable energy resources, the other resources found to be underused in Section 1-5(7) of the IPA Act. Section 16-111.5(d)(2) of the PUA provides that the Plan "shall identify the portfolio of demand-response and power and energy products to be procured." Sections 1-20(a)(1) and 1-75(c) of the IPA Act requires that the Plan include renewable energy resources. In light of the attention paid to demand response and renewable energy, the Commission does not believe that the legislature would have remained silent regarding energy efficiency if it indeed intended for energy efficiency to be part of the Plans.

In addition to the lack of clear language authorizing the procurement of energy efficiency as a resource, the EEAR proposal suffers from other problems as well. For example, the IPA has not specified the quantity and term of energy efficiency it intends to seek. Even if the quantity and term were specified, it is difficult to see how EEAR can be considered "a standard wholesale product" as required by 16-111.5(b)(3)(iv) of the PUA. Setting aside this obstacle for the moment, the Commission observes that obtaining any level of energy efficiency as part of the Plan may result in too much power and electricity being procured given the other procurement efforts described in the Plan. The IPA also neglects to describe how it would ensure that any energy efficiency procured under the Plan would not overlap or be double counted with energy efficiency acquired under the EEPS programs. The spending limits under Section 8-103 are also not addressed by the IPA.

In light of these statutory and practical concerns, the Commission finds that the IPA should not attempt to procure energy efficiency as another resource under the Plan.

B. Demand Response

1. ComEd Position

ComEd complains that although rejected in 2009, the IPA again proposes that it acquire demand response for ComEd on top of the several opportunities PJM provides for acquiring demand response resources. ComEd asserts that the Plan refers to the acquisition of demand response as a "free-standing obligation," the meaning of which ComEd is uncertain. Buying still more demand response, regardless of the price, is not likely to be cost effective, ComEd argues. Moreover, ComEd insists that doing so amounts to simply buying excess capacity-qualified resources, above and beyond the significant demand response already available, and will increase costs to consumers. ComEd indicates that the IPA further proposes to acquire demand response resources for extended terms, up to five to ten years. ComEd asserts, however, that there are no benchmarks for such products and soliciting longer-term commitments only increases the risk to customers.

PJM, ComEd explains, already acquires the necessary demand response through the markets that it administers and the RPM auction process. ComEd also asserts that PJM already offers a broad array of demand response programs in which customers participate. ComEd states that some of its own eligible retail customers who can offer demand response participate in the RPM process through such programs as ComEd's air conditioning cycling program, as well as through other offerings from curtailment service providers. Those processes, ComEd insists, also satisfy all the requirements of Illinois law. According to ComEd, demand response capacity resource providers are eligible to bid on the same basis as generation resources. ComEd asserts that PJM selects the lowest bids from either the generation resources or the demand response resources and pays the winning bidders the clearing price.

According to ComEd, the IPA's proposal is premised, first, on the assumption that there are untapped demand response resources available that can be cost-effectively procured outside of the PJM process. ComEd indicates that the Commission rejected a similar plan in Docket No. 09-0373. While the IPA must presume that something material has changed to favor a separate procurement, ComEd claims the Plan identifies no such change and, if anything, the facts even more clearly support rejection of the IPA proposal this year.

Purchasing additional capacity-qualified demand response resources through a separate IPA-managed process will not, according to ComEd, reduce the costs paid by customers, no matter the price at which the incremental demand response might be acquired. Rather, ComEd claims what is certain is that the added cost of the incremental purchases will be borne by customers, increasing their costs. ComEd maintains that additional demand response resources can not be expected to be cost-effective because they can not be expected to affect the quantity or the price of the resources ComEd must acquire through the RPM process. To truly lower the cost of capacity to customers, ComEd says the IPA and Commission should strive to have all demand response resources participate in the PJM auction which could result in a lower clearing price for capacity. ComEd claims that the quantity of capacity resources that it must acquire is (1) generally determined three years in advance; (2) based on a long-term econometric model that considers more than a decade of data; and (3) based on load during peak hours. To determine the amount of capacity that must be purchased, ComEd reports that PJM uses an econometric model that incorporates load data going back to 1998. To affect the PJM load forecast, ComEd asserts that any demand-resources procured through the IPA process would have to be implemented (not just available) during the time of the PJM peak load each year. Finally, ComEd asserts that because PJM forecasts load based on many years of historical data, excess demand response resources would not impact the model for years. Buying more capacity-qualified demand response resources in an IPA-administered process, ComEd insists, is simply buying more than ComEd needs. ComEd adds that the IPA acknowledges that the RPM capacity prices for the June 2011-May 2014 period have already been determined through a competitive bid process administered by PJM. Buying more demand response, ComEd maintains, will not change that cost, it will only add to it.

The IPA suggests, ComEd states, that additional demand response might have some value as a peak shaving tool. ComEd complains that this assertion, however, is not accompanied by any support, or by any analysis, of the degree to which any such benefit might be realized through an additional solicitation for demand response resources outside of the PJM programs. ComEd argues that "pure speculation" can not justify an additional procurement, especially when there are valid and proven reasons to reject it. According to ComEd, the facts show that an additional demand response solicitation is not likely to have such an effect. ComEd states that it already procures a large amount of demand response resources that reduce peak demand, and there are already ample opportunities for customers to provide demand response through ComEd or other agents and aggregators participating in PJM's programs.

In ComEd's view, the IPA offers no new evidence supporting an additional demand response procurement and points to no new fact that would lead to a conclusion directly opposite to what the Commission reached last year. ComEd states that the only difference appears to be that, in February 2010 PJM decided to hold two, instead of three, incremental auctions for replacement resources after the initial process. In its August 2010 Draft Plan, ComEd observes that the IPA noted and speculated that this may indicate that the RPM processes may not be capturing all potential or available demand response resources. According to ComEd, the facts show just the opposite and PJM's action reinforces the Commission's decision last year to reject a separate IPA demand response procurement. ComEd asserts that PJM made clear that the purpose of the cancelled Second Incremental Auction would have been to allow procurement of added capacity resources when unforced capacity obligation increases relative to the load forecast, that is when there is an aggregate need for more resources under the PJM standards. ComEd claims that PJM cancelled this incremental auction because there was no such need to acquire additional resources when it expected the load to be the same or lower than the original forecast. If anything, ComEd contends this casts further doubt on the cost-effectiveness of buying more demand response. ComEd argues that this auction was cancelled because PJM had already procured all of the capacity resources necessary to ensure resource adequacy, so procuring more capacity resources would equate to incurring unnecessary costs that would be passed on to customers.

2. AIC Position

AIC objects to the IPA's proposal that demand response resources be procured during the spring 2011 procurement events as "a free-standing obligation and not related to the replacement of Capacity Resources." (Plan at 36) AIC states that Section 16-111.5(b)(3) of the PUA requires that cost-effective demand response measures be procured only when the cost is lower than procuring comparable capacity products. AIC believes that this IPA proposal raises two critical questions related to this section of the PUA that must be resolved prior to its inclusion in the final Plan.

First, it is not clear to AIC how the IPA intends to show that the cost of the demand response measures procured under this proposal is lower than procuring comparable capacity products. The IPA is proposing a "free-standing" procurement event, which AIC understands will not allow participation by traditional capacity suppliers as a means to determine the cost of traditional capacity resources. According to AIC, the only visible market for traditional capacity resources is the Voluntary Capacity Auction ("VCA") administered by MISO. AIC states that the VCA is a monthly auction which takes place approximately 40 days prior to the operating month for which capacity is being auctioned. AIC states that there will be no visible market data for the operating periods required by the IPA for the demand response procurement event being proposed until long after the procurement event is complete. Without visible market data and without giving traditional capacity resources the ability to bid directly into the procurement event, AIC is concerned that there will be no way for the IPA to determine if the cost of the demand response resources is lower than procuring comparable capacity products.

Second, AIC expresses concern regarding the value of procuring the demand response resources included in the IPA proposal if they are "not related to the replacement of Capacity Resources." According to AIC, demand response resources are generally considered an alternative to the traditional capacity resources required to satisfy the resource adequacy requirements of MISO. Because the IPA proposes to procure demand response resources in addition to the traditional capacity resources, AIC fears that this would result in additional, unnecessary costs that would be borne by its customers.

AIC insists that the IPA proposal is also flawed in that it does not specify the quantity of demand response to be procured. As part of past procurement cycles, the IPA has set forth it's desired hedge plan for capacity which called for procuring 100% of the required capacity for the upcoming year, 70% for year two, 35% for year three, and no capacity for years four and beyond. Given that this proposal is for contract terms between five and ten years, AIC contends that any amount procured would be outside the bounds of the IPA's desired hedge plan. AIC suggests that the Commission not approve such an open ended proposal that does not specify a quantity to be procured. AIC also notes that many, if not all, of the IPA's responses to the criticisms of its inclusion of demand response resources in the Plan relate to PJM's demand response programs, which do not apply to AIC.

3. IPA Position

Although the Commission rejected its proposal in Docket No. 09-0373 to procure demand response, the IPA insists that the Commission's decision to rely on PJM's demand response measures continues to be contrary to the PUA. The IPA argues that Section 16-111.5(b)(3)(ii) of the PUA requires the Plan to include a mix of demand response products where the cost of the demand response is lower than procuring comparable capacity products. The IPA states that ComEd's objections make the point, however, that PJM's demand response auctions acquire additional resources only when it expects the load to be the same or lower than the original forecast. Quoting from PJM's notice, ComEd notes that PJM's auctions "are conducted only when there is an increase in the RTO's unforced capacity obligation due to a load forecast increase." The IPA contends that the PUA imposes a different metric to determine when demand response is procured – demand response is procured when the demand response price is less than the price for capacity products – not when there is a need to do so based on changes in the load forecasts. According to the IPA, the PUA requires direct purchase of demand response where the cost of demand response is lower than comparable capacity products. The IPA adds that PJM auctions do not rely on or reference the market price of capacity. The IPA alleges that ComEd tries to avoid its obligations to purchase demand response by relying on its purchase of capacity from PJM, driven by load requirements. The IPA maintains that Section 16-111.5(b)(3) requires demand response to be purchased when the price is less than comparable capacity, untied, and irrespective of its commitments to PJM. The IPA also contends that there is no showing that the PJM demand response is procured from eligible retail customers, which is required by Section 16-111.5(b)(3)(ii). The IPA claims that PJM's demand response program relies on curtailment service providers, who act as agents for the customers participating in demand response. In response to AIC's criticisms of the Plan provision for acquiring demand response resources, the IPA relies on its response to ComEd's criticisms. The IPA recommends that no modifications be made to the Plan's demand response procurement proposal.

4. AG Position

As the Commission reviews the Plan under Section 16-111.5(d)(4) of the PUA, the AG wishes to also remind the Commission in its Brief on Exceptions that under Section 16-111.5(b)(3)(ii), the Plan "shall include . . . the proposed mix of demand-response products for which contracts will be executed during the next year . . . ." The AG argues that this provision clearly reflects the General Assembly's intent that demand-response be a key component of the IPA procurement. The AG adds that the Commission should only modify the Plan if the IPA has abused its discretion under the statute.

The AG maintains that power that is never acquired due to demand response measures will clearly reduce not only total capacity costs, but supply, transmission, distribution and other costs. Any conclusion to the contrary, the AG asserts, ignores this cost-saving effect as well as the advantages of peak-shaving, i.e. avoiding purchases when the costs are highest. The AG states further that demand response can also result in greater efficiency and will be more environmentally sustainable because it will avoid producing the pollution attendant to power generation. The AG adds that shaving peak demand also promotes price stability.

5. Commission Conclusion

The IPA discusses its demand response proposal as it pertains to AIC at page 36 of the Plan and as it pertains to ComEd at page 52 of the Plan. The proposal generally appears to be the same for both utilities. As noted above with regard to energy efficiency, the least expensive power is frequently the power never acquired. Because demand response avoids the need for additional power by decreasing peak demand or shifting demand from peak to off-peak periods (see Section 1-10 of IPA Act), the Commission appreciates the significance of demand response in managing portfolio costs.

Section 16-111.5(b)(2) of the PUA provides that the Plan shall include an analysis of the impact of any current and projected demand response programs. Section 16-111.5(b)(3) states that the Plan shall include "the proposed mix of demand-response products for which contracts will be executed during the next year. The cost-effective demand-response measures shall be procured whenever the cost is lower than procuring comparable capacity products . . . ." The IPA relies on this language to support the inclusion of demand response in the proposed Plan.

The IPA made a similar proposal concerning demand response in Docket No. 09-0373. Upon considering the relevant statutory requirements and analyzing the practicality of that proposal, the Commission rejected the proposal. With regard to the pending Plan, ComEd and AIC oppose the IPA's demand response proposal and raise many of the same concerns cited by the Commission when it rejected the demand response proposal in Docket No. 09-0373.

The Commission acknowledges that the PUA requires the IPA to reflect cost-effective demand response measures in its procurement Plans. But the Commission does not read the IPA Act or the PUA to require demand response to be included as part of any procurement Plan regardless of cost and regardless of whether a utility is already procuring demand response through another means. When considered in conjunction with Section 8-103 of the PUA, the Commission is not persuaded by the IPA's arguments that Section 16-111.5(b)(3) of the PUA separately requires demand response to be part of its Plans above and beyond that obtained under Section 8-103. In this instance, ComEd is already procuring cost-effective demand response through the PJM RPM auction. The Commission does not mean to suggest that the IPA is barred from including supplemental demand response measures in a Plan, but if such supplemental demand response is to be part of a Plan, the record must contain sufficient cost support to justify its inclusion in the Plan. As the Commission noted in its decision on this issue in Docket No. 09-0373,

> It would appear highly unlikely that the IPA could successfully reduce ComEd's capacity costs by procuring supplemental demand response measures, unless it were somehow tied to the PJM process. Any demand response measures outside of the PJM RPM process would be additive to ratepayer bills due to the RPM construct of obligating capacity resources 3 years in advance. The Commission deems this element of the IPA Plan to be vague and unviable. We believe that we would be remiss in our oversight responsibility to endorse such a choice especially

> when a more tenable alternative is readily at hand. (Docket No. 09-0373 at 153)

The Commission is still faced with this dilemma and absent more persuasive arguments by the IPA, the Commission does not find that demand response resources above that called for by Section 8-103 need be included in the pending Plan. As a practical matter and perhaps most importantly, it also does not appear likely that the IPA could successfully reduce capacity costs by procuring supplemental demand response measures for ComEd. As for AIC, the Commission questions whether the IPA could obtain cost-effective demand response resources for AIC given that MISO's Aggregator of Retail Customers proposal is still under consideration at FERC and rates and charges under that proposal are at this date unknown. The Commission, however, strongly encourages both the IPA and AIC to investigate opportunities for cost-effective demand response available to AIC prior to the Commission taking up this issue again, but again cautions the parties to provide sufficient information including an example transaction between all participating parties that can provide the Commission the assurance that any demand response acquisition proposed by the IPA is, indeed, cost effective.

The Commission hereby directs that the Plan be modified consistent with this conclusion. In future proceedings, the parties are welcome to offer further information and arguments, at which time they will be duly considered by the Commission. The Commission also invites comments on AIC and ComEd's meeting of demand response obligations under Section 8-103 to facilitate deciding whether demand response is appropriately included in the next Plan. In addition, the Commission strongly encourages the IPA to better support its arguments in future proceedings, rather than just repeating previously rejected arguments.

C. Procurement of Renewable Resources

1. Iberdrola Position

Iberdrola believes that the IPA's 2011 Plan should include a basket of renewable products and not simply one-year RECs. Aside from making reference to the statutory budget caps for meeting RPS goals, Iberdrola complains that the Plan offers no explanation or analysis as to why only one-year REC renewable energy resources are being proposed. Iberdrola states that acquiring one-year RECs as the sole renewables procurement was initially proposed and determined to be inappropriate as the only means of acquiring renewable energy in the last Plan. In the prior Plan, Iberdrola asserts that the IPA eventually proposed that the Plan should include RECs as well as long-term renewables contracts. Iberdrola relates that when considering the prior Plan, the IPA reasoned that the acquisition of long-term renewable bundled energy products (energy and RECs) is an important means of acquiring renewable resources for the utilities.

After heavy litigation of the issue in Docket No. 09-0373, the Commission approved of long-term contracting for the procurement of renewable resources.

Iberdrola contends that the strong legal and policy reasons supporting the Commission's conclusion in that docket remain valid and justify the inclusion, at a minimum, of a bundled long-term renewable procurement in the pending Plan along with RECs. The IPA, Iberdrola insists, must not retreat from the sound reasoning and practices set forth in its defense of the prior Plan. Iberdrola believes that those legal and policy arguments also continue to be dispositive of the issue of mid-term and long-term renewables. No rehash of this fundamental principal, Iberdrola avers, should be entertained in each and every annual procurement. Iberdrola believes each year's procurement should maintain continuity with prior years and important procurement measures like long-term renewables contracts and the rejection of only one-year REC procurement must not be abandoned from year to year.

Iberdrola believes that in order to fulfill the goals of the PUA, as well as to meet Illinois RPS requirements, the IPA must conduct a broad renewable energy resource procurement in 2011, just as it did in 2010. Iberdrola also believes that an appropriate renewable energy procurement for the 2011 Plan should include three components: (1) 20% one-year REC contracts; (2) 30% three- to five-year REC contracts divided into 10% tranches for three, four, and five years, respectively; and (3) a 20-year contract for renewable energy resources commencing in 2012 representing the remaining 50%. Iberdrola contends that the IPA's reasoning in the 2010 Plan to adopt a portfolio approach to renewable energy acquisition is a wise and practical one. Iberdrola maintains that the mix of renewable products it proposes would provide a balanced portfolio of resources which should capture a broader range of price efficiencies.

Iberdrola states further that the 2010 long-term renewables contracts procurement has been largely unsatisfactory and continues to be bogged down in confusion and complexity. Iberdrola asserts that a major reason for this state of affairs is approval of Appendix K in Docket No. 09-0373. Iberdrola relates that Appendix K was intended to establish a framework for long-term renewables power purchase agreements ("PPA") and provide detail regarding the contract terms and provisions. Iberdrola states that Appendix K was developed and proposed by the IPA in a supplement to the Plan filed on November 9, 2009, nearly two months after the 2010 Plan was filed. Iberdrola claims the Appendix K principles were developed privately among four selected participants that did not include members of the renewables development community. Iberdrola contends there was no opportunity to seriously analyze or contest the "hastily prepared" and "ill conceived" Appendix K, since the deadline for requesting a hearing had passed.

In light of the lack of input from the wind development sector in drafting Appendix K, Iberdrola states that a major concern was that some of the Appendix K principles might severely limit the ability to finance and, thus, the type of resources that could be bid. Iberdrola was also concerned that certain credit and termination provisions highly favorable to the utilities would render the standard contract problematic. Iberdrola laments that Appendix K sets forth requirements for a long-term renewables contract that are not prescribed by statute and that are not at all reflective of long-term energy contracting principles. As such, Iberdrola asserts that Appendix K seems to be the result of a collaboration of parties that have little understanding of the realities of long-term renewable power purchasing and contracting.

Iberdrola also complains that the workshops and other opportunities for further work on Appendix K were illusory, at best. Although the Commission involved itself considerably in deciding contract terms and conditions by approving Appendix K, Iberdrola alleges that the Order in Docket No. 09-0373 left a number of unresolved issues to be addressed in subsequent procedures, as well as having directed that certain issues be clarified in a workshop format. Under such circumstances, Iberdrola claims an appropriate amount of time in which to conduct necessary workshops and an opportunity to enable the stakeholders to exchange ideas for serious consideration was warranted. Iberdrola states that over eight months passed before the IPA took any action whatsoever.

When it did act, Iberdrola complains that the IPA issued the 2010 proposed contracts and sought comments on them within nine or twelve days of their posting. Iberdrola also complains that the IPA posted two significantly different contracts for ComEd and AIC and the procurement events were scheduled simultaneously. Iberdrola notes that the comments on the contracts were never made public. One week after the submission of comments, Iberdrola reports that the IPA announced three sessions described as workshops to be held August 30-October 1, 2010. Iberdrola characterizes the workshops as hurriedly organized in the midst of the procurement event. Moreover, because the workshops were held after the contracts had already been drafted, Iberdrola contends that little opportunity was given for fruitful or fair discussion of the issues. Iberdrola asserts that the moderators of the workshops gave the impression that no contract modifications would be seriously entertained and that the sessions were little more than perfunctory. Furthermore, Iberdrola alleges Appendix K was frequently used as justification for refusing to entertain discussion at the workshops, even in instances where the Order in Docket No. 09-0373 allowed for parties to address those details in the workshop and implementation phases of the procurement.

Iberdrola further asserts that the IPA and its workshop moderators refused to offer any detail as to how it arrived at any decision to include a particular contract provision or whether or not to revise the contract. According to Iberdrola, this, along with the refusal to make comments public represents a "shocking" lack of transparency and left the impression that the process was never intended for the purpose of sincerely considering the input of the participants. Iberdrola feels that the workshops were simply conducted to offer the perception of compliance with the Commission’s directive for workshops. In Iberdrola's view, the process involved little meaningful exchange and participants with questions or recommendations about the proposed standard contract or the process were largely ignored. Iberdrola claims that the process bore little resemblance to a workshop or other forum designed to elicit ideas or improve upon the proposed contracts. Iberdrola contends that it appeared as though the intent was to present a “take it or leave it” document that would not realistically promote renewable energy development in Illinois or attract any broad-based participation in the 2010 renewables procurement. The verbal comments of the parties, Iberdrola asserts, left little doubt that the onerous credit, risk allocation, and utility pass through provisions would eliminate any development projects from being bid and would likely only attract merchant projects which would bid higher prices to account for the skewed risk apportionment.

Iberdrola explains that it believed that the initial long-term renewables contract drafting process warranted a robust workshop process because the IPA had never before fashioned a long-term contract for the procurement of renewable energy. Iberdrola avers that the standard terms and provisions in such contracts are distinctly different from the short-term essentially financial contracts that the IPA has employed for the procurement of brown energy. Iberdrola asserts that the need for a long-term renewables contract which contained standard credit and risk allocation provisions was even more imperative in view of the IPA's stated intent to interest bidders with development resources. Iberdrola says only generally accepted provisions that provide for a secure revenue stream would enable developers to obtain the financing to be able to bid a project into the procurement.

Had the IPA intended the workshops to provide an opportunity for stakeholders to offer substantive input into the contracting process, Iberdrola claims the workshops would have been logically held before the contract was drafted and posted for bid. Iberdrola is puzzled as to why the IPA waited over eight months after the 2010 Order to post and solicit comments on proposed contracts and conduct workshops on the contracts one week before it solicited bids on the contracts. According to Iberdrola, the IPA sought to force conclusion of discussions and the contract finalization process in basically three weeks.

In Iberdrola's view, the process employed by the IPA to formulate standard industry contracts that reflect generally accepted terms and provisions is flawed and unfair. Iberdrola contends that the Commission needs to require procedures that will result in a transparent process in which the views of participants are publicly distributed and in which an open and fair exchange of ideas takes place. Iberdrola says it is not recommending that the IPA's discretion to formulate a standard contract with generally accepted terms and provisions be limited. Rather, Iberdrola is requesting that the IPA be directed to do so in a manner that is even-handed and demonstrates no bias toward any stakeholder group.

Iberdrola also recommends that the IPA agree to conduct workshops in a specified time frame over a reasonable period of time. Parties at such workshops should be able to engage in public deliberations through which the IPA will receive and respond to the ideas of all stakeholders. Ultimately, Iberdrola envisions the IPA developing a commercially reasonable standard contract that balances risks and contains provisions pertaining to credit and the ability to finance that takes into account utilities, developers, and ratepayer interests alike. Iberdrola contends that only by adopting reasonable and commercially acceptable risk allocation provisions in a standard contract will Illinois ratepayers realize the lowest possible prices for renewable energy. Even if the Commission opts not to include a 20-year long-term renewables contract in the pending Plan, Iberdrola argues that holding such workshops will facilitate the development of an appropriate long-term contract for use in future procurements.

According to Iberdrola, the IPA should agree to issue a draft standard contract following the receipt of input from all industry sectors, including the banking section. Iberdrola also suggests that the IPA adopt a review and comment process in which it incorporates the public posting of all comments and issuance of a final contract upon fair and due consideration of the comments. Iberdrola further suggests that the bid process incorporate sufficient time for bidders to obtain the corporate approvals and financial support that necessarily accompanies the purchase and sale of long-term renewable power. To this end, Iberdrola attached to its October 27, 2010 reply to the responses to objections a proposed schedule for the ComEd and AIC long-term renewables procurement workshop and comment process.

Iberdrola believes that adopting its proposed procedure for obtaining long-term renewable resources in the 2011 Plan would considerably clarify matters and encourage new and existing renewable energy stakeholders to bid on the RFP, thus promoting a robust competitive process, which would lead to better prices for ratepayers. Iberdrola claims that it, along with other members of the wind development community, have sought to bring to the attention of the IPA examples of long-term renewables contracts that incorporate generally accepted industry standards. Iberdrola claims that it and Duke provided examples of such contracts with their comments on the draft standard contracts. Iberdrola points out that it also marked up the proposed standard AIC and ComEd contracts to reflect such terms. Iberdrola claims that ironically, the IPA cited a Michigan contract as evidence of the propriety of long-term renewables contracting in Docket No. 09-0373. Iberdrola asserts that the Michigan contract sets forth the standard terms and conditions, as well as reflects standard industry credit and risk apportionment almost identical to what Iberdrola has proposed. Iberdrola believes the IPA is in possession of sufficient examples of appropriate long-term renewables contract formats to enable it to comply with the legal requirement under Section 16-111.5 that it formulate an appropriate contract in its procurements.

Iberdrola also hopes to avoid some of the 2010 renewables contract quibbling associated with the physical versus financial nature of the contracts. Generally, in the context of the 2011 procurement, for the purpose of trying to advance the discussion of sound renewable energy policy implemented through long-term PPAs with Illinois utilities, Iberdrola proposes to use the term physical in the following way. When Iberdrola says physical, it is using a shortcut term that means it would like to be a wind energy generator that sells physical energy at the project busbar to a buyer that takes all risks from the project busbar to any downstream destination. In other words, this use of the term means that the supplier sets up the turbines and gets a stream of energy to the very first connection point to the power grid and is responsible for nothing more or less. The buyer takes title to the physical energy commodity by contractual term at the busbar and schedules the energy away from the project busbar to its eventual destination.

Iberdrola asserts that there are reasons why using this physical paradigm for long-term PPA's is sound public policy. First, Iberdrola states that supplier risks do not necessarily translate into significant ratepayer impact. Renewable energy, Iberdrola contends, is on the fringes of the larger forces affecting rates, not at the core. Iberdrola states that it is at most a marginal effect, lost largely in the rounding of the utilities' larger procurement decisions. Given this general situation, Iberdrola offers that the public policy question would seem to be whether there is any good reason to use physicality to attract renewable energy investment and its benefits to Illinois. One reason in support of this approach, Iberdrola suggests, is that using the physical paradigm does not impose unreasonable risks upon the utility. A utility in Illinois has no RPS financial penalty risk. The utility also has a large supply portfolio that it manages on the RTO grid all of the time. If anybody understands how to mitigate transmission risks and get power from point A to point B reliably, Iberdrola maintains that it should be the utility. Iberdrola argues that the utilities understand the risks on a physical behavior basis because they built the system and so it is far from unreasonable for them to manage this risk for this tiny aspect of their large supply portfolio. Doing so, Iberdrola insists, will not imperil the ratepayers. Another reason that Iberdrola offers is that using the physical paradigm assures conservative investment in Illinois. Iberdrola states that conservative investment means projects will get built. Iberdrola asserts that Illinois has many challenges to meet to implement a sound renewable energy policy and watching fly by night investment schemes go up in flames should not be one of those challenges. The physical paradigm takes that risk off the table, according to Iberdrola.

Notwithstanding the foregoing arguments, however, Iberdrola believes that as to one-year RECs and mid-term RECs, WOW has offered a reasonable proposal. Iberdrola is willing to accept the WOW proposal in recognition that other participants have presented reasonable proposals and because Staff has indicated that should the Commission direct the inclusion of mid-term RECs, Staff could support the WOW proposal. Iberdrola recommends that the WOW five-year mid-term RECs constitute 15% of the 2011 RPS budget instead of the lesser 10% which Staff discusses. Iberdrola states that using the 15% amount will enable ratepayers to take greater advantage of the relatively lower REC prices that presently prevail.

Iberdrola also replies to Staff's suggestion that lessening the risk on suppliers would increase the risk for ratepayers. Iberdrola insists that it is simply not helpful to assume an axiomatic, one for one, teeter totter of risk behavior between suppliers and ratepayers. A more reasonable approach, Iberdrola offers, would be to look at how the mutual risks of the ratepayer and the supplier might be reasonably accommodated with the best interests of both taken into account by mediation through the utility. Even if this even-handed balancing of interests is not taken because of an overemphasis on the interests of the ratepayer at the expense of other concerns, Iberdrola suggests that a more helpful discussion of risk still be undertaken. In such a discussion, Iberdrola states that the essential issues are how might the price for and behavior of the supplier of renewable energy most consequentially threaten the ratepayer and that the laudable public policy goals of bringing clean renewable energy, tax dollars, local jobs, and infrastructure improvement to Illinois will likely cause ratepayers to pay a price for electricity that would be higher than otherwise.

In the simplest model, Iberdrola states that if a utility were acquiring a large, materially significant portion of its supply portfolio as renewable energy, and that energy would suddenly disappear and not be delivered, the replacement costs could conceivably drive up the price of energy to ratepayers.[3] In the IPA procurement, however, Iberdrola points out that wind energy is a relatively small portion of the utility's supply portfolio. Even if every MW of its renewable supply would dramatically and permanently disappear overnight, Iberdrola contends that it is difficult to imagine this causing an immediate, or even material price spike for ratepayers. Even if increased renewable energy replacement costs would be amortized across the utility's entire procurement costs, Iberdrola asserts that the effect would likely be lost in the rounding.

For the sake of argument, however, Iberdrola suggests that these facts be disregarded and assume that the effects of a dramatic disappearance of renewable energy would be material. Iberdrola states that the first way that renewable energy might disappear is if an expected project is not built at all, i.e., its construction is not completed. Iberdrola asserts that the way to avoid this risk is to do what is possible to attract developers with solid financial capabilities and track records of bringing projects on line on time. Iberdrola contends that long-term PPA's with appropriate conditions precedent for financing, interconnection, permits, and turbine acquisition, coupled with delay damages for managing construction milestones would have the effect of enhancing the interest of serious, capable wind developers into the state. Without these contractual terms, Iberdrola states that the risk is that responsible developers will take a pass and developers who are willing to take more severe risks will step up to the plate and fail.

Iberdrola asserts that the second way that renewable energy might suddenly disappear is when an event of force majeure fatally wrecks the project. Iberdrola states that this unlikely kind of circumstance is typically identified by lenders to project developers as a worst case scenario risk, the kinds that are typically in the boilerplate of agreements and the assumption is that if this kind of thing happens, the contract goes away without any financial liability. Letting the supplier go free in these circumstances would not harm ratepayers because, according to Iberdrola, inclusion in the PPA increases the likelihood of reliable suppliers with solid financing actually getting renewable energy to show up in the first place. In other words, Iberdrola argues that inclusion of a force majeure provision in the contract reduces the likelihood of a risky, negligent financing scheme in the first place. Second, if the circumstances actually happen, inclusion of a force majeure provision eliminates the cost of litigation from adding to the replacement dilemma of the utility. In the event of litigation, Iberdrola states that the supplier would just argue force majeure led it to terminate, that it should

[3] Iberdrola observes, however, that a dramatic failure of renewable supply would not give rise to any monetary penalties to the utility for failure to meet its RPS requirements. The Illinois RPS imposes no fines or other penalties for noncompliance. In some states failure to buy renewable energy can result in large fines.

not be liable, and that there is common law to support such a position --so why not just write it into the contract in the first place and avoid the problems of not having it there?

Iberdrola also criticizes ComEd's claim that inclusion of a long-term renewable contract in the 2011 Plan will exhaust 60% of the available RERB budget. If the renewables budget is $22.8 million for long-term renewables, and the 2010 procurement results in 1,400,000 MWh, Iberdrola calculates that the price paid for long-term renewables will be only $16.29/MWh per REC. Iberdrola argues that ComEd has shown no evidence as to why the entire budget would successfully procure 1,400,000 MWh at this price when it cites long-term PPA prices of $55-94.43/MWh in an energy market of $32.50/MWh. Adding ComEd's energy market price to its expected REC price yields a long-term PPA price of only $48.79, which is less than all of the prices ComEd has cited. Furthermore, Iberdrola states that the RERB budget will grow each year as the renewable targets increase. If no other long-term procurements were administered by the IPA, except for the 2011 proposal by Duke and Iberdrola and the 2010 Plan, Iberdrola states that that percentage of budget could fall to a deminimus percentage in 2015 and in 2020.

Iberdrola contends as well that ComEd's suggestion that half of its residential customers might switch to a RES over the next 20 years is completely unsupported and unlikely if current trends continue. Iberdrola notes that in its 2010 report to the Commission (see http://www.icc.illinois.gov/electricity/switchingstatistics.aspx), ComEd related that in December, 2010, 460 of its 3,427,179 residential customers switched to an ARES or, as reported by ComEd, 0.0%. In December 2009, 185 residential customers (0.0%) switched to an ARES. In December 2008, 173 residential customers (0.0%) switched to an ARES, and in 2007 it was zero residential customers. Iberdrola points out that ComEd gives no support for its estimate that over the next 20 years, this number could increase to 1.7 million from essentially zero. Iberdrola states that AIC makes a similar argument that it fails to support and the available data does not appear to indicate any significant load loss trends for AIC.

Iberdrola finds equally unavailing ComEd's argument that no 2011 long-term contract is warranted given the "substantial commitment" that the IPA has made in the 2010 procurement event. Iberdrola asserts that ComEd fails to point out that the short-term only approach has added risk and uncertainty and how additional long-term contracts would dramatically reduce the risk. Moreover, Iberdrola continues, the IPA has committed to procure 2,000,000 MWh in Illinois under long-term contracts in the 2010 procurement. At 35% net capacity factor, this amounts to 652 MW of nameplate wind. In Illinois and adjacent states, Iberdrola states that there were 7,011 MW of wind generation operating (see http://www.awea.org/publications/reports/4Q09.pdf). Iberdrola states that this "significant commitment" is less than 10% of the available resources under long-term contract, assuming no construction in 2010 through 2025.

In its November 10, 2010 supplemental comments, Iberdrola offers a compromise under which it would withdraw its proposal that the Plan include a long-term renewables contract. In exchange for this concession, Iberdrola urges parties to agree that 15% of the RERB be used to acquire five-year mid-term RECs. In addition, Iberdrola asks that the Commission require workshops to address various areas of concern related to the procurement long-term renewable energy. Such workshops, Iberdrola continues, would also be used to aid the IPA in developing a standard long-term renewables contract. Iberdrola also proposes guidelines to be used in any workshops. Iberdrola urges the Commission to accept its compromise offer so long as a reasonable number of the parties support it.

2. WOW Position

WOW complains that the Plan fails to take steps to procure long-term renewable products that will ensure environmentally sustainable electric service. WOW believes the purpose of the RPS is to promote growth of renewable generation, and that the Plan should be revised so that it develops a portfolio of renewable products that hedges risk in a way that promotes growth of as much renewable generation as possible within the limits of RERB. In WOW's view, over-procurement of one-year RECs does not provide the necessary income or stability for continued growth of renewable generation. Instead, WOW proposes that the IPA procure a mix of long-term, mid-term, and short-term products. WOW believes that key factors that need to be looked at in making such a change are the RPS volume target and the renewable resources cost effectiveness test. Given the utilities' supply forecasts for the next five years, WOW estimates the RPS volume target will increase to just less than 4.6 million RECs in 2015-2016.

WOW asserts that the procurement plans from 2008 to 2010 have heavily leaned toward procuring one-year RECs. WOW claims that RECs yield a fraction of the revenue that a developer obtains from the sale of energy. According to WOW, development of wind resources is usually done by independent power producers who do not have a captured rate base to rely upon as a revenue stream. Typically, WOW claims, they rely on longer-term contracts to encourage cost-effective development. WOW contends that without a long-term contract the developer has to choose between operating as a merchant project – which WOW claims is next to impossible to receive financing for at this time – or postponing development until a long-term contract is available. WOW asserts that projects financed with multi-year contracts have lower risk for lenders, reducing the cost of capital. WOW states that longer contracts can be obtained directly from project developers, thereby reducing the mark-up and marketing costs of third party REC traders. In contrast, WOW claims that continued use of one year RECs to fulfill the RPS results in developers sitting on the sidelines while the RPS requirements increase. In WOW's view, the result is that renewable resource development will not keep pace with the increasing demand and the costs of renewable resources will increase over time. Ultimately, WOW believes the failure to procure contracts of sufficient length to support construction of renewable resources at a pace equal to the RPS will increase the cost of renewable resources in future procurements.

WOW's forecast starts with the Reference Year Delivered Volume for 2009-10 and escalates using the rate of growth from delivery year-to-delivery year as reflected in the Supply Requirements Forecasts from the utilities. The utility forecasts, WOW asserts, include a gap in the 2009 to 2011 period. To calculate the escalation rate from 2009-2010 to 2010-2011, WOW states that it used the System Supply Requirements Forecasts the utilities provided for the 2009-2010 delivery year and adjusted the numbers to match the 2010-2011 System Supply Requirements Forecast volumes. WOW indicates that the adjustment was made through the use of a factor that equated the sum of the on-peak and off-peak values from the 2009-2010 Procurement Plan System Supply Requirements Forecast to those of the 2011-2012 Procurement Plan System Supply Requirements Forecast. That factor, WOW adds, was then used to adjust the 2009-2010 data to the 2010-2011 utility forecasts.

In 2012, WOW states that the IPA is required to start purchasing solar RECs ("SREC"). According to WOW, the number of SRECs to be procured for the utilities needs to be estimated. WOW asserts that the IPA has indicated that it will forego the ramp-up percentages for SREC procurement, as recently prescribed by the General Assembly. WOW claims that the IPA intends to allocate 6% of the long-term renewable energy and RECs that were approved by the Commission in Docket No. 09-0373 to solar renewable energy resources. WOW therefore made the following three assumptions: (1) that 6% of the 2,000,000 long-term RFP RECs will be procured as SRECs and allocated to ComEd and AIC in proportion to the amount of RECs each is procuring; (2) that 6% of the total RECs procured in 2015 will come from solar renewable energy resources; and (3) that the IPA will procure SRECs in equal amounts between 2012 and 2015. WOW provides a table showing its forecast of the SREC volume target.

In calculating the residual volume of the RPS requirement, WOW says other factors that need to be accounted for are the multi-year renewable energy products procured in prior years and whose contract term is still effective. According to WOW, in the Order in Docket No. 09-0373 the Commission approved the procurement of a long-term renewable energy and RECs to be delivered from 2012 to 2032 in the amount of 600,000 MWh/year for AIC and 1.4 million MWh/year for ComEd. WOW states that this procurement has not yet occurred, but claims the most conservative analysis would be to assume it is fully procured.

Given the preceding assumptions, WOW contends there is still sufficient residual volume in the RPS volume target to procure both one-year and five-year RECs in the 2011 procurement. WOW provides tables that it says account for the impact of the SRECs, the 20-year product whose delivery starts in 2012, and its proposed five-year RECs for AIC and ComEd. According to WOW, the year with the smallest volume target will be the 2012-2013 period. WOW contends that its proposal leaves between 7.5% and 23% of the Planning Year RPS Volume Target for procurement of one-year RECs in the 2012-2013 procurement. In WOW's view, there is plenty of residual volume in the RPS volume target for the IPA to procure 200,000 and 550,000 five-year RECs for AIC and ComEd, respectively. WOW adds that the RERB contains sufficient funds for such longer-term RECs and that residential customer switching should not be a concern given the utilities' switching forecasts.

With regard to Staff's recommendation that something in the range of 10% to 15% of the RERB be set aside or used for the five-year RECs, WOW states that it would split the difference and use 12.5%. The 200,000 five-year RECs that WOW recommends for AIC is about 21% of AIC's RPS Volume Target for 2011-2012 while the 550,000 five-year RECs it recommends for ComEd is about 26% for ComEd's RPS Volume Target for 2011-2012. Since the volume of five-year RECs WOW proposes for ComEd is a larger percentage of its' RPS Volume Target (26% versus 21% for Ameren), WOW states that a slightly higher portion of the RERB should be used for ComEd's procurement. The exact percentage for each utility should be weighted based on the five-year RECs percentage of the respective utility's RPS Volume Target. Thus, WOW recommends that 11.8% of AIC's RERB be used for five-year RECs and 13.2% of ComEd's RERB be used to procure five-year RECs.

The focus of sustainability, WOW states, is to manage the environmental consequences of electricity production to meet the needs of the present without compromising the ability of future generations to meet their own needs. WOW contends that a plan should have an eye toward minimizing fossil-fuel generation's impact on land, water, air, habitat, and communities so as to conserve the environment for the citizens of Illinois, and nearby states, for future generations.

WOW argues that this requires a long-term vision. WOW claims part of that vision is set by statute – procure renewable energy resources or their RECs for at least 25% of the eligible customer load by 2025. WOW observes that cost is always a focal point of energy procurement and the General Assembly has provided guidelines on that. WOW indicates that renewable energy resources are not subject to the lowest total cost over time standard, but are to meet the guidelines set forth in Section 1-75(c) of the IPA Act. WOW states that Section 1-75(c) establishes the RERB in place of the least-cost standard used in Section 16-111.5(d)(4). The RERB is an acknowledgment of the General Assembly that Illinois ratepayers are willing to pay more than least-cost to have zero or low emission generation. The IPA and Commission, WOW continues, need to take steps to conserve energy resources in a fiscally responsible manner. In WOW's view, this requires a plan to ensure growth of renewable generation at cost levels below the cost effective standard, as defined under the PUA. To do so, WOW contends that the IPA needs a long-term goal for procuring renewable products of varying type and contract length.

WOW argues that there needs to be a balance between longer-term products and shorter-term products. WOW claims that renewable resources should have their own portfolio with products laddered in over a period of time, similar to the way the IPA treats standard wholesale block energy products. WOW believes a mix of renewable products of varying duration would allow for the growth of renewable resources in a cost effective manner and hedge against price volatility. WOW contends that as more renewable generation is built there will be greater competition which will drive the price down to market price or lower.

With regard to Iberdrola's proposal to procure renewable energy resources through long-term contracts in 2012-2013, WOW does not object. WOW argues that longer-term contracts for renewable energy provide price stability in the energy portfolio and supports new development that can offset environmental impacts of fossil-fuel generation. Each type of generating resource has advantages and disadvantages; if a utility relies too heavily on any one resource, WOW asserts, it will increase costs, risks, and reliability problems and those disadvantages are passed along to ratepayers. WOW believes that incorporating renewable resources will take advantage of the strengths of renewable and conventional resources while minimizing the disadvantages of conventional resources. Given some forecasts that coal production will soon peak, WOW states that the United States may be at the beginning of a major restructuring of energy generation. As such, WOW asserts that the zero to low cost of wind and other renewable energy resources make them a perfect hedge against the risk of that price volatility. Hedging against future policy change, WOW continues, is another important reason that Illinois utilities should diversify its generation resources. Change in environmental regulation of fossil fuel plants in the country continues to be discussed. Additional regulation of emissions including carbon, mercury, and other pollutants is currently under serious consideration. WOW maintains that the price impact of those changes would make the wind generation provided through the long-term contracts a very good deal for Illinois ratepayers.

With regard to Iberdrola's November 10, 2010 compromise offer, WOW asserts that the proposal provides a valuable benefit to the procurement process by making future contract discussions more efficient. WOW generally concurs with Iberdrola's characterization of the contract development process under the prior Plan. With three relatively minor exceptions, WOW supports Iberdrola's compromise offer.

3. Duke Position

Duke notes that the Plan at issue in Docket No. 09-0373 contained a section entitled "Carbon Liabilities" as part of a broader discussion of risks to be considered and mitigated in the procurement process. Duke can not understand why a similar discussion has been omitted from the currently pending Plan. Duke insists that there is no justification for such a change; carbon constraints remain likely in the future, whether at the federal, state, or regional level, and fuel source diversity remains an important hedge against the unknown. Duke argues that while that very real risk remains, so does the potential benefit of federal and state incentives for energy from low-carbon alternatives like wind– as do the compelling benefits to Illinois' economic development and the environment.

The Commission, Duke believes, should require that the 2011 Plan continue to utilize procurement of long-term renewables. Rather than ignoring a vital source of long-term environmental and economic benefits, and of prudent long-term risk mitigation, Duke asserts that the 2011 Plan should build on the policy set forth by the IPA in the last Plan. In Duke's view, the Commission should use this opportunity to improve the process with regard to renewables. Duke states that the late inclusion of the long-term renewable provisions in the last Plan, and the even later controversial amendment to add Attachment K, resulted in a delayed and uncertain process that continues to experience delays to this day. Duke suggests that an earlier start on renewable issues in 2011, with early hearings to work out any concerns, will help ensure that the same problems are not experienced in implementing the 2011 Plan. Conversely, Duke claims that if the long-term renewable provisions are removed after one year, and there is no continuity of effort to refine the procurement process for long-term renewables, it will discourage development of the renewable power sector in Illinois. Given the increasing RPS standard and the considerable economic impact that new development projects could have in Illinois, Duke believes such a result would be contrary to the intent of the legislature.

Duke also observes that each year the IPA has chosen to meet the RPS requirement solely through the one-year purchase of RECs. Duke understands the IPA to believe that this is economically preferable to the purchase of actual power from renewable sources. Duke notes that this was true even in the last Plan, where the provisions for long-term renewable energy procurement were included.

Duke states that the definition of “renewable energy resources” in the IPA Act includes RECs, however, Duke believes that does not tell the entire story. Duke notes that Section 1-75(c) provides that “[a] minimum percentage of each utility’s total <u>supply to serve the load</u> of eligible retail customers . . . <u>shall be generated</u> from cost-effective renewable energy resources.” (Emphasis added by Duke) Duke points out that RECs do not directly provide supply to serve a load, nor do RECs directly generate supply. While “renewable energy resources” generally may include RECs, separate from the energy, Duke believes the specific context of Section 1-75 suggests that the procurement plans should favor procurement of supply (or supply with its associated credits), not just credits.

In Duke's view, such a preference makes sense as a matter of policy. While purchase of RECs provides some support for renewable energy generation, Duke claims there are two aspects of the IPA’s use of RECs that minimize the positive impacts of the program on development of a robust alternative energy economy in Illinois. First, Duke states that purchasing the RECs independent from the power leaves the owner of the generation still seeking a purchaser for the power output itself. Second, Duke asserts that the one-year decision framework under which the IPA is purchasing RECs provides inadequate certainty for a developer making investment decisions. With neither an assured purchaser of the outputs, nor even long-term certainty as to a purchaser of the RECs, Duke insists there is little incentive for a developer to risk investing in Illinois. Given the large role the IPA plays in the Illinois market, Duke believes the signals from the IPA carry enormous weight – enough to determine whether the pro-growth policies in the statute are achieved in practice.

Duke contends that the type of long-term renewable energy procurement the IPA prescribed in the 2010 Plan, if done correctly, could provide the certainty and incentive for additional renewables investment in Illinois. Duke believes such a result would fulfill the intent of the statute to promote the use of renewable energy, to secure environmental benefits for Illinois, to spur investment and economic development, and to provide long-term stability in energy supply and costs. Duke says the obvious caveat is that the procurement must be done correctly. Onerous terms that make project financing unobtainable, or which shift project risk to the developer to an unreasonable degree, Duke argues, will prevent Illinois from achieving the benefits of the “green economy” that other states are actively seeking.

Duke is concerned that despite the IPA’s correct analysis in the last Plan that long-term renewables procurement was prudent and desirable, the contentious responses and replies and the problems with the process that has actually played out in that Plan have resulted in the IPA deciding it is not worth the effort. Duke believes that is precisely the wrong response. According to Duke, carbon risks still exist and the environmental and economic goals of the statute remain in place. In Duke's view, having gotten the policy right in Docket No. 09-0373, the correct approach is that the IPA and Commission should work in 2011 to get the implementation right as well. Duke asserts that the best way to achieve that is to bring interested parties together, including a wide array of experts (such as those in the areas of development and finance) and determine the most effective way to establish a stable, predictable, and fair procurement process for renewables.

The IPA’s restrictive view on the role of renewables, Duke contends, is shown by more than just the omission of long-term procurement of energy from the pending Plan. Duke says the IPA continues to look solely to short-term RECs without considering the potential price-stability in medium or long-term REC purchases. Duke asserts that this is a particularly important procurement cycle because Section 1-75(c)(2) requires that the Commission review the limitation on the amount of renewable energy resources procured pursuant to subsection (c) and report no later than June 30, 2011 to the General Assembly its findings as to whether that limitation unduly constrains the procurement of cost-effective renewable energy resources.

To the extent that the IPA has focused predominantly on one type of procurement (short-term RECs), Duke believes the Commission is provided a limited base of information. Duke contends that a more expansive procurement of renewables, and the process to get there, would provide the Commission a much broader base of experience on which to base its report. Duke insists that more important than making the report easier, however, is the policy purpose indicated by the reporting requirement itself. Duke avers that the goal, like that of the annual increases in the RPS, is to facilitate additional procurement of renewable energy. Duke believes this goal is best served by a broader, rather than a narrower, view of renewable energy procurement. In that light, Duke argues that the IPA’s move from inclusion of long-term renewables in the last Plan to the omission of long-term renewables in the pending Plan is a step in the wrong direction, and one to which Duke objects.

Duke believes that the simple solution is to add language to the pending Plan reaffirming the intent expressed in the last Plan to procure long-term renewable energy resources. Duke provides specific modifications to the Plan in an effort to facilitate this process within the Commission's timeline. As a final specific proposal, Duke reiterates its view of the importance of moving quickly to resolve these issues and provide certainty, predictability, and efficiency in the long-term renewable procurement process. In the 2010 process, Duke claims the timeframes provided to potential bidders have been unrealistic. Duke asserts that to provide a thoughtful bid and obtain necessary internal approvals, particularly for a large, long-term contract, takes more than the one week allowed in the 2010 schedule, and a properly designed process will reflect those real-world business needs. In the end, Duke believes this will benefit Illinois by encouraging additional participation in the bidding, and encouraging such bids to be well-constructed. Duke recommends that the Commission make a firm commitment to continue to include, and expand, the procurement of renewable energy, making clear that the process will be transparent and realistic.

Duke notes that the primary criticisms of its recommendation are that: (1) it did not provide specifics or studies to support its objections, (2) the one-year RECs that are included in the plan are the least expensive way to meet Illinois' RPS and therefore are the only renewable resources needed in the 2011 Plan, and (3) the 2010 procurement of long-term renewables and its impacts are not yet known, so no further long-term procurement should occur at this time. Duke contends that these criticisms miss the fundamental point of its objections. Duke asserts that there are no detailed analyses because its concerns are with a threshold issue of law and policy that must be resolved before details are relevant. In addition, the suggestion that the decision to omit long-term renewables should be driven solely by comparison to the price of short-term RECs does not defeat Duke's concerns – it corroborates those concerns, in Duke's opinion. Duke's objection is that while the IPA Act sets forth multiple policy objectives to be balanced – adequate, reliable service; low cost over time; but also environmentally sustainable electric service – the 2011 Plan looks at only a single factor: short-term cost. In their responses to its objections, Duke observes that none of the parties argue that short-term RECs are effective at promoting economic development, or ensuring the viability of environmentally sustainable electricity sources "over time," as required by Section 1-75 of the IPA Act. Moreover, Duke argues that the increasing RPS over time and the initial preference for in-state sourced renewables strongly suggests that both environmental and economic development policies generally motivate the RPS provisions of the IPA Act. Duke reiterates that the 2011 Plan does not make an effort to balance these various policy goals; the analysis stops at short-term costs. Duke repeats its concern that this is short-sighted. Development of a renewable energy infrastructure and the jobs, investment, and economic development that come with it does not happen overnight and it does not happen without regard to regulatory climate. Duke contends that omitting support for purchase of long-term energy resources from the 2011 Plan raises the risk that Illinois will miss opportunities as green investments flow elsewhere.

In light of its substantial expertise and experience in developing, constructing, and operating alternative energy generation, Duke states that the ability to sell short-term RECs provides neither sufficient return nor sufficient certainty over the life of the project to effectively encourage investment. When the central procurement process is a substantial driver of the available market, and purchase of the power output itself is not part of the plan or is only intermittently part of the plan, Duke states that the risk of being unable to sell power sufficient to cover costs (and of being able to sell RECs for only a given year) is a level of risk that chills investment. Without that investment, Duke avers that the longer-term goals of the IPA Act can not be met. According to Duke, continued reliance solely on short-term RECs is simply less effective at meeting the statutory goals of encouraging facilities development (and particularly in-state facilities development) than entering long-term PPAs for power supply – a point no respondent challenged.

Duke states that the Illinois Department of Commerce and Economic Opportunity has found that a robust renewable energy industry in Illinois could create thousands of new jobs and millions of dollars in new economic activity in the next decade – but only if there is actual investment in tangible development here. Duke maintains that Illinois will miss out on such opportunities in the future if the state's commitment to long-term investments in renewable energy is unclear. The regulatory climate is impacted by the 2010 and 2011 Plans (and the differences between them) both at the macro level – the omission of long-term renewables from central procurement in the 2011 Plan – and at the micro level – the alleged delays, difficulties, and industry-disfavoring terms in the 2010 Plan implementation. Duke contends that the Commission should require the 2011 Plan to balance short term costs with long-term policies favoring development of renewable energy infrastructure. The best way to do so, Duke argues, is to include procurement of long-term renewable resources, and in doing so to address some of the concerns that have troubled the 2010 procurement.

As referenced above, Duke believes that the best way to avoid the problems associated with long-term renewables in the 2010 Plan is to (a) start early, (b) consistently address long-term procurement efforts, and (c) utilize the expertise of industry to fine-tune the bidding and contracting procedures. Duke understands the reasoning behind the "wait and see" approach concerning the yet-to-be-completed 2010 long-term procurement, but fears that this approach is certain to repeat the same problems that have plagued the 2010 long-term procurement event. Indeed, with only a few weeks until the 2011 Plan decision is required, Duke states that the fact that the parties can point to the 2010 long-term renewables procurement as something that "remains to be seen" highlights the problem. Given the difficulties associated with the last Plan and now the absence of renewable energy (as opposed to credit) purchases in the pending Plan, Duke indicates that it will re-evaluate its future investment plans to account for what Duke sees as the investment risks presented by the difficulties of selling renewable outputs into the central procurement process.

In response to Iberdrola's supplemental comments and compromise offer, Duke asserts that the positions taken therein are reasonable and constitute an acceptable resolution to the renewables issues in this docket. Duke supports the proposal in part because by including mid-term RECs, diversification of the basket of products is advanced. Furthermore, Duke believes that by setting up a workshop framework that is structured and inclusive, the IPA should be able to develop a contract that is appropriate for long-term renewable purchase or procurement that is broadly accepted by all participants in the procurement process.

4. AIC Position

AIC notes that Iberdrola recommends modifying the 2011 Plan to include a “basket of renewable products” consisting of 1) one-year RECs, 2) three- to five-year RECs, and 3) long-term renewable energy contracts. AIC complains that Iberdrola does not include any analysis that illustrates a “basket of renewable products” is superior to the short-term approach included in the Plan. AIC asserts further that Iberdrola completely ignores the ongoing long-term renewable RFP process and the quantities being pursued when making this recommendation.

The current long-term renewable RFP, AIC explains, could result in contracts that would satisfy in excess of 50% of AIC's 2012 RPS requirement. AIC believes that the possibility of such a large quantity of contracts resulting from the current RFP must be considered when discussing any additional intermediate or long-term renewable procurement. But because, in AIC's opinion, Iberdrola neglects to consider that possibility and generally fails to support its own argument, AIC urges the Commission to reject Iberdrola's modifications to the Plan.

With regard to Iberdrola's claim that the draft standard renewables contract does not satisfy generally accepted industry practices, AIC contends that Iberdrola appears unwilling to concede the differences between its past contracts and those contracts necessary in a retail choice state with a legislated procurement process for the utilities. According to AIC, the unique characteristics by which the utilities purchase power in Illinois and the fact that all customers in Illinois can switch to alternative suppliers leaves the utilities with considerable risk if certain provisions are not captured in its contracts. In AIC's view, these parameters were properly included in Appendix K to the last Plan. Without the Appendix K provisions to which Iberdrola objects, AIC argues that it would not be possible for a utility in a retail choice state such as Illinois to enter into a long-term contract such as this. Finally, AIC asserts that there is nothing about the Iberdrola proposal that suggests that its proposal is somehow standard in the industry. Rather, AIC claims Iberdrola’s recommendation includes its own preferred contract terms.

AIC states that Appendix K set forth various long-term contract parameters. AIC claims that these parameters are specific in nature and need to be memorialized in any contract resulting from the current RFP. Iberdrola argues that the IPA and Procurement Administrator have been inflexible in negotiating terms Iberdrola finds acceptable. Upon reviewing the objections set forth in Iberdrola’s pleading, AIC alleges that it becomes clear Iberdrola ultimately desires certain parameters set forth in Appendix K to be changed, whereas the IPA and Procurement Administrator are attempting to develop a contract that implements key parameters defined in Appendix K. AIC finds Iberdrola's argument self serving in that Iberdrola desires to dictate the terms of any contract based on Iberdrola’s definition of generally accepted industry practices. AIC contends that the

PUA makes clear that it is the role of the Procurement Administrator to develop the standard contract forms and credit terms.

AIC relates that Iberdrola also suggests that the Commission should direct the IPA to follow fair and transparent procedures in developing standard contracts. According to AIC, the PUA gives the Procurement Administrator the authority to design the final procurement process and its associated contract terms. AIC believes Iberdrola is asking the Commission to supersede this authority in a manner inconsistent with the provisions of the PUA. In AIC's view, Iberdrola's arguments represent another veiled attempt at redefining key parameters of Appendix K to its advantage. AIC recommends that the Commission reject Iberdrola's objection that the IPA is not following fair and transparent procedures in developing contracts.

AIC notes that Duke also objects to the exclusive use of short-term RECs to satisfy the RPS and seeks the inclusion of specific language in the Plan that would require the procurement of long-term renewable energy products. Duke's language calls for the solicitation of "longer term power purchase agreements with renewable energy providers" for an amount limited to 600,000 MWh per year for AIC and 1,400,000 MWh per year for ComEd. AIC contends that Duke makes this recommendation without offering any analysis as to the impact of procuring an additional 600,000 MWh per year of renewable energy on top of the 600,000 MWh approved in the last Plan and for which a RFP is currently in progress. If Duke's recommendation is approved, AIC believes that it is important to note that 1,200,000 MWh of annual RECs would be in excess of AIC's forecasted 2012 REC requirement. AIC argues that doing so would add unnecessary cost to customers and may be in violation of the RPS requirements. AIC claims that Duke offers no analysis backing its preferred option, which would result in excess REC procurement, and should therefore be rejected by the Commission.

WOW recommends that a five-year REC product be included in the pending Plan with quantities of 200,000 RECs per year for AIC and 550,000 per year for ComEd. AIC states that its current forecast shows that the annual quantity of RECs recommended by WOW will require an additional quantity of RECs to be procured in the short-term markets for each of the five years in the planning horizon. In other words, using the current AIC forecast as the basis, the proposal set forth by WOW should not result in excess REC purchases across the five-year planning horizon. AIC cautions, however, that the risk to this proposal is a scenario where customer migration to suppliers other than AIC is much higher in the next five years than what is currently forecasted. Given that scenario, AIC notes that it is conceivable that the WOW proposal could result in REC purchases in excess of RPS requirements. This is a risk AIC suggests the Commission should consider when making its ruling. Despite such concerns, AIU does not appear to oppose the inclusion of a five-year REC only product in the pending Plan.

AIC provides a brief response to Iberdrola's November 10, 2010 compromise offer. AIC questions the propriety of the workshops that Iberdrola suggests. As AIC understands it, the workshop proposal would make it the responsibility of an independent facilitator and a drafting committee consisting of representatives of each stakeholder to draft a model long-term renewables contract. AIC argues that this proposal is in direct conflict with Section 16-111.5(e)(2) of the PUA, which makes it the responsibility of the Procurement Administrator, in consultation with the utilities, the Commission, and other interested parties to develop the contract forms used in the procurement events.

5. ComEd Position

ComEd notes that both Iberdrola and Duke object that the Plan does not provide for the procurement of long-term renewables. ComEd contends, however, that neither party provides any support for the inclusion of the procurement of such resources in the Plan. Iberdrola states that it does not believe it is necessary to revisit the propriety of including long-term renewables contracts in the pending Plan. Similarly, Duke contents itself with citing from the last Plan. ComEd asserts that neither party presented any "data or other detailed analyses" in support of their objections, as they are required by the PUA to do.

According to ComEd, since Iberdrola and Duke failed to provide any support for their objection, the Commission does not need to address the issue of whether the Plan should include the procurement of long-term renewables. Nevertheless, should the Commission decide to consider the issue, ComEd offers the following three reasons why the procurement of long-term renewables is unreasonable and should not be included in the pending Plan: (1) the price for long-term renewables will likely be at a significant premium to current prices for short-term RECs, and no analysis has been offered that demonstrates customers are better off paying this premium; (2) the statutory target and budget amounts for the utilities' procurement of renewable energy resources in future years may be substantially less than forecast today making long-term commitments very risky; and (3) following the long-term renewables procurement event approved in last year's Plan, the IPA will already have committed a substantial portion of the available budget amount to the procurement of long-term renewables.

ComEd maintains that neither Iberdrola nor Duke made any attempt to demonstrate that the procurement of long-term renewables is beneficial for customers compared to the procurement of short-term RECs. ComEd argues that available evidence suggests otherwise. ComEd states that the recently completed 2010 procurement event for ComEd resulted in very favorable REC prices, i.e. $5 for Illinois wind RECs and $4.40 for Illinois non-wind RECs, under the short-term (one-year) procurement held by the IPA. In future procurement events, ComEd suggests prices for one-year RECs may be even lower since the Illinois locational preference will expire in June 2011. ComEd says additional supply from states adjoining Illinois will then be able to compete to meet the needs of ComEd's customers. According to ComEd, the 2010 procurement event for ComEd also resulted in an average ATC price of about $32.50/MWh for the 2010-11 planning year. Adding the $5 REC price yields a total price for renewable energy resources obtained by the IPA in the 2010 procurement event of about $37.50/MWh. ComEd asserts that while there is not a transparent market for the purchase of long-term renewables, the evidence of which ComEd is aware suggests that the price of long-term renewables is typically much higher than the short term price the IPA is able to obtain. ComEd is concerned that its customers will be paying a premium in the near term if more and more long-term renewables contracts are required.

ComEd believes long-term hedges can be beneficial when one has a known long-term exposure that needs to be mitigated. ComEd claims this is not the case with the obligation to meet the Illinois RPS requirements. First, ComEd says its RPS requirement is stated as a percentage of the ComEd customer load. This means that as ComEd customer load drops, due to customer switching or to weak electrical demand, the amount of renewables ComEd needs to purchase declines as well. ComEd asserts that over a 20-year contract term, such load reductions can be substantial. ComEd claims this risk is even greater given some recent developments in Illinois relating to a purchase of receivables program and municipal aggregation, which were designed to enable Retail Electric Suppliers ("RES") to capture more of the utility's current customer base.

ComEd states that its RPS requirement is subject to a rate impact cap which is effectively set at 2.0% for the 2011 procurement event and will be set at 2.015% for all future procurements. If the rate impact cap is reached, which ComEd claims is likely over just the next ten years given the inclusion of the solar renewable energy standard, the amount of renewables ComEd says it can purchase will either be reduced below the RPS target amounts or, more likely, the statutory preferences for wind and solar will not be met (i.e. the Procurement Administrator will lower the amounts of each REC type/locational preference to try to stay within the cap).

ComEd also indicates that the IPA has not yet completed the long-term renewables procurement approved by the Commission in the prior Plan. Additionally, ComEd states that the IPA Act is constantly changing (three times in the last three years) as the legislature continues to debate and change the exact nature of the requirements that utilities and RES need to meet. Given the allegedly uncertain nature of the amount of renewables that need to be hedged, ComEd believes that it makes no sense to enter into additional long-term contracts at this time.

ComEd states that the budget for the procurement of renewables for planning year 2011 is $77 million. According to ComEd, the Procurement Administrator for the 2010 procurement event has allocated $22.8 million, or about 30% of the 2011 planning year's budget, for the procurement of long-term renewables, all of which ComEd believes will likely be needed. If Duke's proposal to obtain an additional 1,400,000 MWh of long-term renewables is accepted, ComEd claims another $22.8 million will need to be committed to long-term renewables.

The situation would be worse, ComEd contends, if a significant number of its customers were to switch to a RES. ComEd suggests that if half of its residential customers switch to RES supply over the next 20 years, the renewables budget would decline 50% to approximately $39 million, which is some $6 million less than the $45 million that the IPA will already have committed under long-term contracts. ComEd says this would mean that either existing contracts for long-term renewables would need to be curtailed or, if not curtailed, that costs in excess of the statutory caps would have to be passed on to ComEd's remaining customers.

Assuming no changes in its load, ComEd states that the 2025 target RPS requirement would be about 8.8 million RECs. ComEd contends that the IPA will have already spent $45 million on the first 2.8 million RECs at an average price of about $16/REC. If the IPA is to procure the target amount of RECs, ComEd claims it will need to purchase the remaining 6.0 million RECs for $32 million or about $5.33/REC. ComEd believes this would be a very difficult result to achieve if the IPA is to continue to observe the statutory wind and solar preferences in the law. Given the relatively high price of long-term renewable energy, it seems far more likely to ComEd that using lower cost short-term renewables will enable the IPA to meet statutory RPS requirements.

ComEd believes the IPA and the Commission have already made a very substantial commitment to renewable developers in the 2010 procurement event. While even one long-term commitment adds risk given the uncertain nature of the obligation being hedged, ComEd asserts that adding more long-term contracts on top of previous ones would dramatically increase that risk. Therefore, ComEd strongly recommends that the Commission reject proposals for the procurement of additional long-term renewables at this time and instead allow the IPA to follow its proposed Plan, which ComEd says balances expected long-term commitments from the prior Plan's long-term renewables procurement with short-term REC purchases.

In ComEd's view, the Commission should not lightly embark on establishing contract terms. While Iberdrola and Duke may be requesting the litigation of only a handful of contract issues, ComEd is concerned that if they are allowed to raise their issues, then all other parties should be allowed to raise the issues that are of importance to them. The procurement contracts, ComEd indicates, are nearly 100 pages long and address numerous of issues between the parties. ComEd claims the procurement proceedings could rapidly become overwhelmed by such issues.

ComEd states that contract development is only one of the functions that the PUA delegates to the IPA. ComEd indicates that the IPA is also required to develop the solicitation, pre-qualification, and registration of bidder process; to establish the market-based benchmarks; to develop the RFP competitive procurement process; and to develop a plan implementing contingencies. If parties can raise contract issues in the procurement proceeding, ComEd suggests there would be no reason why issues relating to any of these other IPA-delegated responsibilities could not also be raised.

ComEd notes that Iberdrola also recommends that the IPA procure three- to five-year RECs. Similarly, WOW states that the IPA should develop a portfolio of products and should not rely on the procurement of only one-year RECs. ComEd states that WOW then goes on to recommend that the Plan be modified to include a requirement that ComEd enter into a contract for 550,000 RECs/year for a five-year period. ComEd contends that neither party offered any substantive support for their proposal. According to ComEd, it appears that both parties believe that the adoption of their proposal will result in a more balanced portfolio which somehow is supposed to benefit consumers. ComEd argues that in reality, this proposal would lead to a very unbalanced "portfolio of products." One result of such proposals, ComEd calculates, would leave only 8% of REC purchases for the lowest cost annual RECs. ComEd opines that such a result hardly seems like a prudent balanced portfolio. In fact, given the low costs of one-year RECs, ComEd suggests it would be in the customer's best interest to have the majority of the REC purchase portfolio be annual RECs.

ComEd states that while it does not object to the concept of mid-term RECS (although ComEd does prefer three-year as opposed to five-year RECs in order to reduce credit concerns and tie to the length of the energy procurements which cover a three-year time frame), it insists that the previously approved long-term renewables procurement already results in an imbalance toward longer-dated renewables purchases. ComEd asserts that while the proposal to procure mid-term RECs is made under the guise of seeking a balanced portfolio, the resulting portfolio would actually be severely lacking in balance. Therefore, ComEd recommends that no additional multi-year REC procurements be included in this procurement plan. ComEd suggests that in the coming years, there will be room for mid-term RECs as RPS target requirements increase, assuming ComEd's load does not radically drop due to customer switching and also assuming no additional long-term REC contracts are required.

In response to Iberdrola's compromise offer in its supplemental comments, ComEd continues to argue that all that is warranted are one-year RECs. But if the Commission opts to include longer-term RECs, ComEd recommends a renewables portfolio of 50% one-year RECs and 50% multi-year RECs. The multi-year RECs, ComEd adds, can be split between three-year RECs and long-term RECs. With regard to the workshops that Iberdrola proposes for developing a long-term renewable energy contract, ComEd argues that such workshops would be premature and speculative because there is no need to include renewable energy in the Plans and there may never be. In any event, ComEd contends that the described workshops violate the PUA in that they appear to rob the Procurement Administrator of authority over the contract development process.

6. ExGen Position

ExGen considers the inclusion of long-term renewable resource contracts in the Plan a difficult issue. Notwithstanding the protections provided in the Appendix K terms approved in Docket No. 09-0373, ExGen argues that many risks and uncertainties remain. For that reason, ExGen understands and agrees with the factors that appear to have motivated the IPA's decision in the pending Plan to rely on the less risky approach of satisfying the RPS through the acquisition of one-year RECs.

ExGen believes the IPA's position makes sense because there is no experience yet from the prior Plan's long-term renewable procurement much less an evaluation of that experience to enable the IPA to determine whether to repeat the effort. ExGen suggests that the experience the Commission will obtain from the ongoing long-term renewables initiative will provide the basis for the detailed cost/benefit analysis that is needed in this area and that, thus far, has not taken place. In ExGen's view, waiting for the results of the first long-term renewables acquisition before deciding whether to conduct another, and if so on what terms, is the prudent course of action at this time.

ExGen does not oppose entirely the use of RECs for anything other than a one-year term, but says it can not support a multi-year REC proposal without further details that address cost and implementation issues. Whether savings would result from using three- or five-year RECs is an open question, according to ExGen. ExGen also claims there are reasons to doubt for now that there will be any cost advantage as compared with annual RECs. ExGen states further that multi-year REC procurement increases complexity. ExGen suggests that if something other than one-year RECs are to be used, a three-year or a five-year product might be considered, rather than both, particularly for an initial test of the approach. ExGen opposes any use of geographic preferences or requirements as well. ExGen also urges review of the allocation of the renewables procurement among various REC durations and resource types, and ExGen has concerns about open-ended procedural issues, such as the curtailability of each resource and the way in which the statutory cost test would be applied to them.

With regard to Iberdrola's November 10, 2010 compromise offer, ExGen is not opposed to workshops, per se, but contends that this is not a situation in which workshops make sense. One of the main reasons behind ExGen's position is that the pending Plan does not include long-term renewables contracts. In other words, ExGen contends that there is simply no need to create a “standard contract” for a long-term renewable procurement that is not even contemplated in the pending Plan. Additionally, ExGen argues that the proposed workshops would conflict with the procurement provisions of the PUA.

In its Brief on Exceptions, ExGen addresses Section 1-20 of the IPA Act. ExGen argues that this section only enumerates the IPA's general powers and should not be interpreted as requiring any particular action. Sections 1-56 and 1-75(c) of the IPA Act, on the other hand, are more specific and in ExGen's opinion prevail in the face of any ambiguity in applying the three statutory provisions. ExGen, however, does not believe that any conflict exists among the three statutory provisions. While Section 1-20 uses general language, ExGen implies that the reference to "electricity" therein refers to the same "renewable energy resources" for which the IPA Act imposes specific procurement obligations.

7. CECG Position

CECG opposes the acquisition of additional long-term renewables contracts. According to CECG, the assumption that the Commission’s decision to include long-term renewables contracts in Docket No. 09-0373 must lead to a similar decision to include long-term RECs in this year's Plan is without merit, and is contrary to the law. CECG reminds the Commission that it must be guided by evidence in the current proceeding, and may not make its decisions based on other proceedings.

CECG also contends that the current circumstances are different than those surrounding last year's Plan. CECG points out that the Alternative Compliance Payment ("ACP") that was collected for the first time in September 2010 (pursuant to Section 16-115D of the PUA) contemplates purchase of long-term RECs. Based on last year's Plan and the ACP funds, CECG asserts that millions of dollars have already been earmarked for long-term renewables contracts. As the IPA collects additional funds via the ACP in future years, CECG claims that the number of RECs will continue to grow. Thus, to the extent that there is a benefit associated with long-term RECs and/or energy, CECG believes that benefit will have already been achieved outside of the currently pending Plan.

CECG claims further that the procurement of RECs longer than one year can have negative impacts on the competitive market. According to CECG, longer term contracts necessarily include a premium that will be paid for by utility customers, a fact which CECG asserts none of the supporters of long-term RECs and energy deny. By operation of the ACP, CECG claims customers of ARES will also be affected by the premium, given that the calculation of the ACP is specifically derived from the utilities' RPS procurement prices. CECG relates that the IPA has not yet concluded its procurement of long-term RECs flowing from last year's Plan. CECG contends that it is therefore still unknown what the true costs of long-term renewable procurements are for Illinois customers. In CECG's view, the Commission would be well advised to allow sufficient time to assess the impact of the long-term procurements that have already been authorized before embarking on additional procurements that may be harmful to ratepayers and the competitive market.

8. Staff Position

Staff supports the IPA's current proposal to purchase incremental renewable energy resources through one-year contracts for unbundled RECs to be delivered during the June 2011 through May 2012 planning year: 952,145 MWh for AIC and 2,117,054 MWh for ComEd. Staff expresses some concerns with the competing proposals of WOW, Duke, and Iberdrola. WOW recommends that the IPAs' 2011 Plan be amended to procure unbundled RECs using not only one-year contracts, but also some contracts up to five years: 200,000 MWh per year for AIC and 550,000 MWh per year for ComEd. Staff understands WOW to also support the concept of long-term purchase power contracts that bundle RECs with energy. Duke proposes that the Plan be modified to procure RECs bundled with energy, through long-term contracts, with delivery starting as early as the 2012-2013 planning year: 600,000 MWh per year for AIC and 1,400,000 MWh per year for ComEd. Iberdrola proposes modifying the Plan to include the acquisition of three types of renewable energy resource contracts: (1) one-year REC contracts, (2) three- to five-year REC contracts, and (3) longer-term contracts for RECs bundled with energy.

Staff states that it is not, in principle, opposed to long-run PPAs with renewable or conventional power producers. In addition, Staff says that it is not, in principle, opposed to three- to five-year contracts for unbundled RECs, as proposed by WOW and Iberdrola. Staff, however, does oppose vague proposals that do not meet the requirements of the PUA and that place excessive faith in everything being worked out during the Plan's implementation phase, as well as proposals that shift significant risks from suppliers to utilities and ratepayers, without very good reasons. Staff believes that to varying extents, Iberdrola, Duke, and WOW are guilty of tendering such proposals. Furthermore, Staff does not think it is appropriate to acquire additional long-term renewable energy resources while the effort to do so under the prior Plan is still ongoing. For these reasons, Staff recommends that the Commission reject these calls to add one or more long-term renewable energy resource procurements to the Plan.

In explaining its position, Staff complains that Iberdrola does not indicate how many MWh of renewable energy resources it would have the IPA solicit through each of its three proposed mechanisms. With regard to the third mechanism, Staff notes that Iberdrola fails to specify the duration of the proposed long-term contracts. Staff claims that Duke also fails to specify the duration of long-term contracts under its proposal. Also with regard to Iberdrola's third mechanism, Staff indicates that Iberdrola implies that the delivery location should be each project's busbar rather than the utility's load zone. Staff points out, however, that Iberdrola fails to address how this change would affect the value of the delivered energy, how that value would therefore vary by project, and how this variability would create additional bid selection issues. According to Staff, Iberdrola also fails to discuss the risk of its proposal to ratepayers relative to the risk associated with Appendix K.

In terms of risk, Staff contends that Iberdrola's proposal entails greater risk for the utility and/or ratepayers relative to Appendix K. Staff states that Iberdrola dislikes the Appendix K feature that the contracts expressly state the utilities shall not be liable under the long-term contracts for any costs that can not be recovered from customers through the utilities' pass-through tariffs. Staff understands Iberdrola to also claim that no bank would ever finance a project that contained such uncertainty regarding payment and the contract revenue stream. Staff reports that the offending language is contained in what was the "final" Long-Term Master Agreement, posted September 7, 2010 on the website maintained by National Economic Research Associates ("NERA") for the ComEd 20-year renewable RFP. According to Staff, it conveys that ComEd will pay its renewable suppliers unless the government tells ComEd it can not pass through the costs that the government mandated ComEd incur by requiring ComEd to enter into the contract. Staff states that only under such contingency would the contract permit ComEd to curtail purchases (and even then, to the minimum extent possible), unless the supplier prefers to just walk away from the contract. To Staff, that seems quite fair and reasonable, even if it raises concerns for Iberdrola's bankers. Staff states that depending on how one assesses the actual risk that at some point during the 20 years the government will try to take away ComEd's right to recover payments to suppliers under the 20-year contract referenced above, it is conceivable the limited liability provisions may have some actual impact on bidder participation in the RFP, as well as risk premiums embedded in bids. Staff suggests that if bidders and banks have so little trust in the State's willingness to support its own RPS over the next 20 years, then how can ComEd and AIC not be expected to "keep the faith." Staff further suggests that the Commission expects ComEd and AIC to trust the government to not pull the rug out from under their legs, if the likelihood of such a reversal is as palpable as Iberdrola implies.

Iberdrola asserts further that credit support is typically bilateral, applying to both the purchaser and the seller. Staff contends, however, that the utilities' supply contracts typically require suppliers to post collateral as assurance against default, but do not require the utilities to post collateral. Generally, Staff has not objected to this allocation of risk between utilities and suppliers because, unlike suppliers, ComEd and AIC are public utilities that are required by statute to purchase renewable energy resources and are permitted to recover prudently incurred costs associated with those requirements via pass-through tariffs. As such, Staff says ComEd and AIC are not likely to default on supply contracts. Staff states that as seen in many other RFPs, in Illinois and in other states, suppliers are willing to enter supply contracts with the utilities, even when the utilities are not required to post collateral.

Staff says it has considered the potential benefit of making collateral requirements under the supply contracts bi-lateral (that is, imposing similar or identical requirements on ComEd and AIC). In Staff's view, it remains unclear if the potentially lower bid prices that might be obtained if the utilities were required to post collateral with suppliers would entirely offset the higher cost of the utilities posting such collateral since, under either scenario, the costs incurred by the utilities would be passed through to ratepayers via tariffs. In the absence of definitive evidence that utilities have become unusually risky counterparties or that bilateral collateral requirements would lower costs incurred by customers, and subject to further advice provided by the Procurement Monitor, Staff has accepted the recommendations of the Procurement Administrators with regard to such provisions.

Iberdrola also asserts that Appendix K's utilization of a pure derivative contract is not appropriate for long-term renewables contracting and that any contract for long-term renewables should contain appropriate elements of physicality. Staff contends that it is not accurate to call the Appendix K product a "pure derivative," which would be an asset whose value is determined solely by price movements in other assets. Staff states that although one component of the Appendix K product is a financial fixed-for-floating swap (considered a derivative), the quantity is directly tied to the actual hourly output of the resource. Further, Staff contends that the REC component is also tied to the actual renewable resource and is as tangible as any other contract for RECs. Staff contends that the Appendix K product does involve "elements of physicality," as Iberdrola puts it, even if it is not a purely physical contract. Staff believes this is mere quibbling over words. Staff's larger issue is that Iberdrola, with one exception, fails to explain why the combined fixed-for-floating swap and REC contract is an inappropriate form for a long-term contract for renewable energy resources or why a greater degree of physicality is so essential. The one exception, Staff says, is that Iberdrola does indicate that the "passage of Dodd-Frank legislation makes use of such contracts extremely problematic." (Iberdrola Objections at 9) Staff believes this is a fair concern, but one which has already been taken into account in both the instant Plan and in the final 20-year renewable energy resource contracts.

According to Staff, if the provisions in the sample confirmation for ComEd's final Long-Term Master Agreement constitute an insufficient contingency plan, then it would seem that the IPA should petition the Commission to amend Appendix K, accordingly. More generally, Staff states that if the various Appendix K prescriptions add up to something so distressing to potential bidders that the RFP is likely to be uncompetitive (due to a lack of willing bidders), then an alternative should be developed and presented to the Commission as a petition to amend Appendix K. Staff reserves the right, at that time, to examine the alternative, to evaluate how it re-allocates risk sharing between suppliers, utilities, and ratepayers, and to present its analysis to the Commission.

Staff states that based on the level of interest that was expressed for participating in the already-approved 20-year renewable energy resource procurement (even after the RFP and contracts were "finalized"), Staff is not convinced that a significant change to Appendix K would be needed to implement a competitive procurement event. In any event, Staff suggests that it makes sense to observe the results of the ongoing 20-year renewable energy resource procurement before rushing into another long-term procurement. Meanwhile, immediately after the results of the upcoming 20-year procurement are known, Staff encourages the IPA (especially if it shares the enthusiasm for long-term contracts) to begin a workshop process or other investigatory process to begin the design of one or more potential long-term procurements for possible inclusion in next year's procurement plan.

If the Commission is persuaded by the arguments of WOW, Duke, and Iberdrola, Staff notes that WOW's five-year unbundled REC proposal is the most well-defined proposal among the three, and raises the fewest unresolved issues. Hence, if the Commission chooses not to accept Staff's recommendation to reject all three of the long-term renewables proposals, Staff recommends that the Commission approve only the WOW proposal. Staff also claims with regard to Iberdrola's initial proposal that adoption of it could necessitate additional procurement events, which would burden customers because associated costs are ultimately borne by customers. The Commission would also be faced with evaluating the associated Procurement Administrator and Procurement Monitor reports on the procurement events in a limited amount of time. But even WOW's proposal, Staff asserts, leaves two important issues unresolved: the budget for the proposed five-year contract procurement and the integration into the selection process of the solar photovoltaic preferences included in the IPA Act (such preferences become effective in 2012).

With respect to the budget for a five-year REC procurement, Staff recommends utilizing 10% to 15% of the total June 2011 through May 2012 budgets. These percentages are based on Staff's attempt to reasonably allocate the total budget for the five years between the one-year, five-year, and 20-year contacts that would be effective during this time period. Based on the usage and revenues data and forecasts provided by ComEd and AIC, Staff says 10% would amount to a budget of $7,710,937 per year (or, on average, $14.02 per REC) for ComEd and $4,527,020 per year (or, on average, $22.64 per REC) for AIC, while 15% would amount to a budget of $11,566,405 per year (or, on average, $21.03 per REC) for ComEd and $3,018,013 per year (or, on average, $15.09 per REC) for AIC.

With respect to the solar photovoltaic requirement, Staff claims the WOW proposal is unclear with respect to the target quantity and is completely silent with respect to the manner in which the solar preference should be incorporated into the selection process. Staff believes it is noteworthy that the IPA established, in the case of the on-going 20-year procurement, that the solar target would be set at 6% of the total REC requirement. Since the residual requirement would be zero or negative for the first three years, and would be extremely small for the fourth year, Staff recommends setting the solar requirement for the five-year REC procurement (if one is authorized) to zero. Staff suggests that the positive residual SRECs for plan years 2014 and 2015 could instead be sought through one-year REC procurements implemented in each of those two years.

Staff states that its conditional recommendation on quantities, if accepted, renders moot the issue of how the solar preference should be incorporated into the selection process. However, if both of Staff's recommendations - to reject the proposal for a five-year REC procurement in 2011 and to set the five-year SREC target to zero, are rejected by the Commission, then Staff recommends the Commission order that the solar preference be treated with the same priority as the existing wind requirement. To be more specific, Staff recommends that the Commission officially sanction the selection rule that NERA set forth in the Appendix 5 – Evaluation Process of the 2010 Long-Term Renewable Energy and REC RFP Process and Rules for ComEd.

In response to Iberdrola's compromise offer in its supplemental comments, Staff continues to support the IPA's proposal for one-year RECs, but is willing to accept the five-year unbundled REC proposal if the Commission is inclined to do so. With regard to the workshop proposal, Staff is not opposed to workshops but recommends specific revisions to the workshop guidelines Iberdrola proposes.

In its Brief on Exceptions, Staff disagrees with any interpretation of Section 1-20(a)(1) of the IPA Act as requiring the procurement of renewable energy (as opposed to renewable energy resources as defined in Section 1-10). Staff contends that Section 1-20(a)(1) requires the procurement of renewable energy resources, which can be either energy or RECs. Staff places no significance on the use of the word "electricity" in this section of the IPA Act.

9. IPA Position

The IPA urges the Commission to reject the recommendations of WOW, Duke, and Iberdrola on this issue. The IPA points out that the full cost of the Plan approved in Docket No. 09-0373 is not yet known and contends that it would be inadvisable to proceed with additional long-term renewables procurements given that funds in the RERB are not only limited, but not guaranteed. Further, the IPA notes that average prices for REC's have dropped from $30, to $20, to $4.50 in three years. The IPA provides a table showing the average prices for single year RECs secured through the IPA procurement process. With the Illinois preference dissolving, the IPA expects the over-saturated REC market to produce low compliance costs for the RPS throughout the medium-term. Finally, the IPA suggests that procuring variable output resources such as wind does not allow it to procure as much standard power, unless, of course, the renewable supplier wants to guarantee delivery per the same schedules required of standard energy suppliers. Therefore, the IPA believes that incorporating WOW's suggestions are untenable at this time. The IPA, however, does not foreclose similar options in future P0lans. The IPA disagrees with ComEd's position that obtaining mid-term RECs would create an unbalanced portfolio in RECs. According to the IPA, there is insufficient information for ComEd, or the Commission, to reach this conclusion.

The IPA notes Duke and Iberdrola's criticism of the pending Plan for its lack of long-term renewables. The IPA also acknowledges that Duke provides language to amend the ComEd and AIC sections of the Plan. But what Duke contends is "short-sightedness" with respect to the absence of long-term renewables, the IPA contends is careful consideration of the effects of the use of long-term renewables approved in Docket No. 09-0373. In the IPA's view, both Duke and Iberdrola spend an exorbitant amount of time criticizing Appendix K from the Plan approved in Docket No. 09-0373. The IPA believes that comments regarding the prior Plan and Appendix K should be summarily dismissed.

With regard to Iberdrola and Duke's comments supporting adoption of specific terms for long-term renewable energy contracts, the IPA agrees with ComEd's view on this issue. ComEd contends that under the PUA, this proceeding is not the appropriate venue for determining contract terms. The IPA supports ComEd's position that the Procurement Administrator, in consultation with the utilities, the Commission, and other interested parties shall develop and provide standard contract forms.

The IPA opposes Iberdrola's November 10, 2010 compromise offer. A sizable portion of the IPA's response is devoted to defending Appendix K from the last Plan and the long-term renewables contracts derived there under. The IPA also contends that Iberdrola's workshop proposal contravenes the PUA in that it would usurp the authority of the Procurement Administrator.

10. AG Position

In its Brief on Exceptions, the AG urges the Commission to defer to the IPA's judgment on whether to include more than short-term RECs in the Plan. The AG is also concerned about adopting Iberdrola's proposal for procuring long-term renewable energy (as well as short- and mid-term RECs) when the procurement of long-term renewable energy has yet to be completed under the prior Plan. The AG appears to suggest that the IPA should have the flexibility to interpret the IPA Act as it believes necessary.

11. RESA Position

RESA supports the positions of the IPA and Staff that the procurement of one-year RECs for this year's Plan is appropriate and that the proposals of Duke and Iberdrola should be rejected. As for Iberdrola's compromise offer in its supplemental comments, RESA is still not persuaded that five-year RECs are warranted. Moreover, because it would prefer to focus on its own proposal for more frequent procurement events, RESA contends that workshops on long-term renewables contracts would not be a good use of resources. In its reply to the various responses to the compromise offer, RESA observes that support of the proposal is scant and therefore recommends that the Commission not adopt it.

RESA disagrees in its Brief on Exceptions with any suggestion that renewable electricity must be procured through the Plan. RESA argues that because a REC only exists in conjunction with the generation of renewable energy, procuring a REC alone counts as procuring "electricity" under Section 1-20(a)(1) of the IPA Act. RESA also supports waiting until long-term renewable energy procurement is completed under the prior Plan before calling for additional long-term renewable energy procurements.

12. ICEA Position

In its Brief on Exceptions, ICEA argues that when it enacted the IPA Act, the legislature clearly contemplated that RECs alone could be used to fulfill RPS obligations. The supply of renewable energy resources does not, in ICEA's opinion, require the procurement of renewable energy. Moreover, ICEA contends that requiring long-term renewable energy contracts in the Plan runs afoul of the statutory requirement in Section 1-20(a)(1) of the IPA Act that the IPA "ensure adequate, reliable, affordable, efficient, and environmentally sustainable electric service *at the lowest total cost over time . . . .*" (emphasis added). ICEA contends that the proposals in the record for the procurement of long-term renewable energy are devoid of any analysis on which the Commission could reasonably rely to make an informed decision that any proposal is in the best interest of consumers.

ICEA states further that the manner in which the Commission allows the IPA to manage the default service procurement obligations of ComEd and AIC, including compliance with the RPS, has a direct impact on competitive wholesale and retail markets and, ultimately, on consumers' interests. ICEA does not support the Commission adopting policies and protocols for the IPA that has the IPA and the electric utilities entering into long-term contracts for which they receive full cost pass-through protection. ICEA contends that such policies create an untenable investment and competitive conundrum. While competitively bid long-term contracts provide for a modicum of competition among developers, ICEA states that they retain little or no exposure to competitive market outcomes.

13. TradeWind Position

TradeWind agrees with the majority of Iberdrola's November 10, 2010 compromise offer. The only caveat that TradeWind makes pertains to the acquisition of only unbundled five-year RECs. TradeWind explains that allowing this option would only benefit renewable energy producers that already have merchant plants operating, and would, in effect, strand for a period of time other developers' greenfield development assets. TradeWind understands that within the broad policy goals of Illinois, there exists a desire to encourage new wind project construction and renewable energy jobs located within Illinois. In this instance, TradeWind contends that the most efficient way to accomplish this goal would be for the Commission to authorize the purchase of bundled RECs and energy under long-term PPA's. TradeWind emphasizes that short-term REC-only purchase arrangements will not alone support adequate, if any, project financing. TradeWind asserts that an unbundled sale of energy, subject to uncertain nodal pricing as proposed in the pending Plan, does not provide the price certainty typically required by financiers to invest in wind energy projects, and will therefore impede the development of other renewable projects in the state.

14. Horizon Position

Horizon supports Iberdrola's compromise proposal to include five-year RECs in the Plan. In addition, Horizon supports the suggestion that 15% of the RERB be used for the purchase of such. Conducting workshops within established guidelines shortly after the conclusion of this proceeding for the purpose of developing long-term renewables contracts is also appropriate, in Horizon's opinion.

15. IWEA Position

In response to Iberdrola's compromise offer, IWEA concurs with Iberdrola's characterization of the workshop process under the Plan approved in Docket No. 09-0373. IWEA generally supports the proposal that workshops be held after the conclusion of this proceeding to develop a better long-term renewable energy contract. IWEA also agrees with the proposed structure and timeline for the workshops. IWEA explains that many of its members rely on the ability to procure long-term contracts for the purpose of securing financing for the development of future projects and the general sustainability of their business. Therefore, any effort to further development of a viable long-term contract is very important to IWEA members. IWEA, however, does not support the procurement of five-hear RECs. IWEA believes that it is misplaced to continue to place emphasis on shorter term, unbundled renewable products. Rather, IWEA continues, the central focus of renewable procurement should be on long-term products and advancement of the workshop process is a positive step in the right direction. According to IWEA, the IPA should be focused on long-term unbundled renewable energy contracts, rather than one-year or mid-term products. IWEA avers that only long-term contracts will facilitate the development and financing of wind energy projects for Illinois.

16. ELPC Position

ELPC agrees with Iberdrola's characterization of the workshops under Docket No. 09-0373 and generally supports Iberdrola's compromise offer. ELPC, however, proposes limiting the number of mid-term RECs purchased under the pending Plan so as not to preclude or delay the future acquisition of long-term renewable products. In addition, ELPC suggests modifications to two of the workshop guidelines proposed by Iberdrola.

In its Brief on Exceptions, ELPC specifically cautions against requiring the IPA to allocate 50% of its renewable energy portfolio to 20-year contracts, as Iberdrola suggests. ELPC states that a long-term procurement this large would tie up a large portion of the RERB over the next twenty years, potentially threatening the opportunity for future long-term procurements. Constraining the RERB in this way, ELPC contends, would hamper the IPA's ability to develop a portfolio of products that ensures long-term growth of renewable energy resources to ensure success of the RPS through its end date of 2025. Instead, ELPC suggests that the overall size of the 2011 long-term procurement be left to the discretion of the IPA in consultation with the parties. ELPC proposes that this can be accomplished in the workshop process sought by Iberdrola. If, however, the Commission determines that it must set out a specific long-term allocation in its order, ELPC suggests that it be limited to no more than 10% of the budget in the first delivery year.

ELPC is also concerned that there is another major outstanding issue concerning renewable energy procurement that the workshops should also seek to resolve. The pending Plan does not provide any information about how the IPA intends to handle compliance with the solar ramp up requirement over the five-year planning horizon, as required by Section 1-75(c) of the IPA Act. ELPC recommends that the scope of the proposed workshops be broadened to develop a suitable framework for ensuring the cost-effective procurement of solar renewable energy products starting in the 2012 compliance year.

Through discussions with the IPA, ELPC understands that the omission of solar from the pending Plan stems from uncertainty about (1) whether solar resources will be procured as a part of the long-term procurement under Docket No. 09-0373 and if so, how many and at what price; (2) the adequacy of the RERB to support the next five years of RES compliance, including the solar component; and (3) how to fairly design a price-only evaluation process for multiple technology types with vastly different cost and value structures in the context of a single procurement. ELPC considers the IPA's concerns legitimate and agrees that these sources of uncertainty create impediments to including a solar procurement in the pending Plan. ELPC believes that designing an optimal solar procurement strategy will require careful consideration by the IPA and stakeholders. ELPC states that the results of the ongoing procurement under the last Plan must necessarily inform future solar procurements. ELPC also asserts that the second and third concerns expressed above can and should be addressed prior to the 2012 planning year, and that the proposed workshop process is an appropriate forum for resolving these concerns in a thoughtful and transparent way. ELPC suggests three areas of discussion for the workshops pertaining to solar procurement.

17. Commission Conclusion

The Commission appreciates Iberdrola's efforts to resolve through compromise perhaps the most contentious issue in this proceeding. As is obvious from the responses to Iberdrola's offer, however, no consensus exists. The Commission therefore understands Iberdrola's position to be that which it previously advocated.

Evaluating the various conflicting positions is no easy task. To resolve this issue, the Commission will start with a review of the relevant portions of the IPA Act and PUA. Without discussing in detail, it is clear that the legislative declarations and findings in Section 1-5 of the IPA Act support the development and procurement of renewable energy resources. Section 1-10 of the IPA Act defines various terms used therein. Section 1-10 defines "renewable energy resources" as:

> "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, 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. "Renewable energy resources" does not include the incineration or burning of tires, garbage, general household, institutional, and commercial waste, industrial lunchroom or office waste, landscape waste other than tree waste, railroad crossties, utility poles, or construction or demolition debris, other than untreated and unadulterated waste wood.

Section 1-10 defines RECs as:

> "Renewable energy credit" means a tradable credit that represents the environmental attributes of a certain amount of energy produced from a renewable energy resource.

Section 1-20 of the IPA Act sets forth the general powers of the IPA. Subsection (a)(1) provides:

> (a) The Agency is authorized to do each of the following:
>
> (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 this Act.

Section 1-56 of the IPA Act establishes the Illinois Power Agency Renewable Energy Resources Fund, known throughout this Order as the RERB. Subsection (c) provides:

> (c) The Agency shall procure renewable energy resources at least once each year in conjunction with a procurement event for electric utilities required to comply with Section 1‑75 of the Act and shall, whenever possible, enter into long‑term contracts.

Section 1-75 of the IPA Act sets forth the IPA's obligations pertaining to planning and procurement. Subsection (c)(1) establishes the RPS, under which cost-effective renewable energy resources are to be procured in specified percentages. The first part of subsection (c)(1) states:

> (c) Renewable portfolio standard.
>
> (1) 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, procured for each of the following years shall be generated from cost‑effective renewable energy resources: . . . .

Section 16-111.5 of the PUA contains provisions relating to procurement. Subsection (d)(4) of Section 16-111.5 provides:

> (4) The Commission shall approve the procurement plan, including expressly the forecast used in the procurement plan, if the Commission determines that it will ensure adequate, reliable, affordable, efficient, and environmentally sustainable electric service at the lowest total cost over time, taking into account any benefits of price stability.

While discussing what type of renewable energy resources should be included in the Plan, the parties expressed a variety of views on what obligations the IPA and Commission are under. Some argued that there is no requirement that any particular type of renewable resource be procured. Others emphasized that whichever type of renewable resource is procured, it must be the lowest cost option. Still others assert that renewable energy resources are to be procured in a way that ensures maximum growth of renewable generation without exceeding the cost effectiveness test. The Commission has considered the arguments and reviewed the relevant statutory provisions. When a statute is clear on its face, the Commission must abide by it. Section 1-10 defines "renewable energy resources" as either energy and its associated renewable energy credit **or renewable energy credits from renewable energy, such as wind or solar thermal energy** (emphasis added). As noted in Section 1-10 a REC is a renewable energy resource and therefore fully meets the requirement of Section 1-20 of the IPA Act requiring the procurement of renewable energy.

The Commission therefore is not bound to require that the Plan provide for the procurement of renewable energy but rather can simply procure RECs and fully meet the law's requirements. The Commission recognizes that the renewable energy resource requirements of the Plans in the past three years have been met through the procurement of RECs, and only in the most recent plan did the IPA incorporate renewable energy in addition to RECs. AIC and ComEd drafted the first Plans prior to the organization of the IPA as required by Section 16-111.5(j) of the PUA. Those Plans were the subject of Docket No. 07-0527 (AIC) and Docket Nos. 07-0528/07-0531 (Cons.) (ComEd). The IPA crafted the next Plan for the utilities, which was the subject of Docket No. 08-0519. The Plan under that docket represented the IPA's first attempt to implement the new law. The Commission Order in Docket No. 08-0519 encouraged the parties and the IPA to pursue the possibility of acquiring multi-year or long-term renewable resources. The most recent Plan, approved in Docket No. 09-0373, includes the procurement of long-term renewable energy via 20-year contracts. But for reasons not entirely clear, the bidding for the long-term renewable energy is not scheduled to occur until December, 2010.

Some parties have argued that because the long-term renewable energy procurement under the prior Plan has not been completed yet, the Commission should not require the pending Plan to include a similar requirement. They suggest that information and experience obtained from the procurement of long-term renewable energy under the prior Plan will facilitate any future efforts to do so again. The Commission in particular agrees with Staff and the IPA that it is reasonable to analyze the results of the on going 20-year renewable resource procurement to better understand the implications before rushing into another long term procurement. Therefore the IPA's proposal to include in this year's Plan the acquisition of only unbundled one-year RECs through contracts covering the delivery period June 2011 through May 2012 with no long-term renewable energy contracts is hereby approved. This meets the requirement of Section 1-75(c)(1) of including cost-effective renewable energy resources.

Several parties have suggested that the Commission order the IPA to conduct workshops beginning in January 2011 to develop the contract for the long-term procurement for 2011. Because we have determined that we will not conduct a long-term procurement at this time, the Commission declines to set a workshop schedule. We also will rely on the Procurement Administrator and the Procurement Monitor to conduct the procurement events in a manner that is consistent with Section 16-111.5 of the PUA, and report any problems to the Commission. The Commission also encourages the utilities and the potential suppliers of renewable energy resources to meet and attempt to work out terms of the contracts that may be acceptable.

D. Supplier Collateral Thresholds

1. ComEd Position

ComEd notes that the Plan reflects the following recommendation regarding the appropriate amount of unsecured credit (i.e., the collateral threshold) that should be provided to energy suppliers:

> Collateral Thresholds should remain at the levels used in the utilities' existing 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. (Plan at 16)

ComEd believes this recommendation is inconsistent with the PUA and should be rejected.

ComEd points out that Section 16-111.5(e)(2) sets out the process for the development of the standard contract form. This Section provides that the Procurement Administrator is to consult with the utilities, the Commission, and other interested parties in the development of a standard contract. If the Procurement Administrator is unable to reach agreement with the utility as to the contract terms, the Procurement Administrator is to bring the dispute to the Commission who shall then resolve it. In ComEd's view, the IPA's proposal effectively seeks to deny the utility its statutory right to object to any contract term and to have the matter brought before the Commission for resolution. ComEd insists that the IPA has no authority to rewrite the PUA or circumvent protections expressly called for by statute. ComEd believes this provision must be deleted from the Plan for this reason alone.

ComEd also believes this provision should be deleted because the IPA has presented no support, evidence, or reasoning for keeping the unsecured credit levels at the high levels that the IPA proposes. ComEd asserts that if the IPA wants the Commission to resolve the issue now, it should be required to present some support for its position. ComEd argues that since the IPA did not and, in ComEd's opinion, can not support its position, this provision should be stricken.

ComEd relates that in the 2010 procurement event, the Procurement Administrator provided suppliers with a maximum unsecured credit amount of $80 million, which was available to suppliers with the best credit rating. ComEd's understanding is that this unsecured amount is higher than the amount typically seen in comparable circumstances. ComEd notes further that this amount is higher than the unsecured amounts granted by PJM, which provides a maximum amount of $50 million. ComEd adds that it is also higher than what is provided in the New Jersey process, where a maximum unsecured amount of $60 million is allowed. According to ComEd, allowing the Plan to implement overly generous unsecured credit levels would mean that customers will bear additional risks and additional costs if a supplier default occurs. In the absence of any support for such a proposal, ComEd contends that there is no reason to subject customers to this risk.

In its reply to the various responses to the comments, ComEd adds that the collateral threshold proposal should be rejected because (1) it sets a dangerous precedent whereby once a contract term is set, there is a significant (though undefined) hurdle to overcome before it can be changed and (2) neither Staff nor the IPA provides a good rationale for why this specific term should be treated differently than all other contract terms, and why their proposed language should supersede the provisions of the PUA. Such a proposal, ComEd claims, limits the flexibility in the contract development process that is needed to adapt to changing market and economic conditions.

With regard to Staff's argument that ComEd's position is contrary to its position in Docket No. 09-0373 concerning the procurement of long-term renewable energy resources, ComEd contends that the circumstances are different now. Specifically, Staff argues that ComEd did not object to the IPA's Appendix K, which set forth specific collateral requirements for long-term renewable energy resources and RECs, including the types of security the utilities would accept to satisfy those collateral requirements. ComEd acknowledges that certain specific credit terms for long-term renewable resources were included in Appendix K and supported by ComEd in Docket No. 09-0373. ComEd, however, attempts to distinguish last year's procurement docket from this one by asserting that in this proceeding the IPA proposes general restrictions on changes to collateral requirements whereas in the prior docket the IPA proposed and supported specific collateral requirements. Additionally, ComEd states that the PUA specifically requires agreement by the utility "as to the contract terms and conditions," and requires Commission resolution of any dispute. ComEd agreed to the specific credit terms proposed in Appendix K in Docket No. 09-0373, consistent with statutory requirements, whereas no specific credit terms are proposed and supported here.

ComEd does not contend that the Commission may never address a contract term or credit requirement in the context of approving a procurement Plan, but insists that such an action must be the exception and not the rule given the clear process dictated by statute. In this situation, ComEd states that the issue involves collateral requirements for standard products that have been included in prior Plans. In Docket No. 09-0373, ComEd relates that the Commission was addressing a new proposal for the procurement of long-term renewable resources that was objected to on multiple grounds by a number of parties, and those objections were resolved via the additional detail and conditions in Appendix K. ComEd maintains that the circumstances of Docket No. 09-0373 were special and justified the Commission's approval of certain specific contract terms there (with the agreement of the utility), whereas the situation here does not justify adoption of the process change proposed in the Plan.

ComEd claims that the IPA and Staff are asking the Commission to set a dangerous precedent. If a party can select one contract issue and ask the Commission to ratify it solely on the basis that it has been in a previous contract, ComEd states that then any party can select any other issue in the contract, or indeed select the whole contract, and ask the Commission to approve all such previously used language and thereby prevent or limit further discussion among the parties on those issues. ComEd contends that this was clearly not the intent of the process in the PUA.

2. Staff Position

According to Staff, collateral thresholds are unsecured credit limits that the utilities grant creditworthy suppliers. Staff states that all else being equal, lowering thresholds increases supplier risk because it raises the amount of collateral suppliers must post with the utilities. Conversely, raising thresholds reduces supplier risk because it lowers the amount of collateral that suppliers must post with the utilities. Staff states that higher thresholds mean utilities have less collateral to call upon in the event of a supplier default. As such, Staff relates that utilities grant suppliers threshold amounts based on credit ratings. That is, utilities grant the highest threshold amounts to suppliers with the highest credit ratings and do not grant unsecured credit to suppliers without requisite credit ratings. Staff does not propose to reduce collateral requirements for the utilities' energy contracts.

Staff reports that for the past two procurement cycles, ComEd and AIC contracts have included identical threshold amounts, with both utilities granting counterparties with the highest credit ratings an unsecured credit limit of up to $80 million. In Staff's view, changing thresholds absent a compelling reason could cause suppliers to view the utilities' thresholds as arbitrary and uncertain. Staff states that currently, energy and capacity contracts have terms up to three years; hence, changing thresholds affects existing contracts as well as participation levels in future RFPs. Therefore, Staff avers that under no circumstances should thresholds used in future contracts affect threshold levels under existing contracts. Staff asserts that as with all risk factors, suppliers will make bids that include a price for this uncertainty (i.e., risk) and utility customers will pay the price for such risk.

Staff finds ComEd's objections to the collateral thresholds flawed and urges the Commission to disregard ComEd's objections. Staff recommends that the Plan remain unchanged in this regard and notes that it merely maintains the threshold level used by the utilities in the past two procurement cycles. Moreover, Staff asserts that the proposed threshold recommendation does not limit the ability of the Procurement Administrator to change threshold levels when compelling reasons warrant doing so.

Staff agrees that Section 16-111.5(e)(2) of the PUA provides that contract terms under dispute are to be brought to the Commission for resolution, but Staff also avers that nothing in Section 16-111.5 prevents those issues from also being addressed as part of the Commission's review and approval of the IPA's Plan. Adopting the threshold recommendation in the Plan would not, in Staff's opinion, circumvent any protections expressly called for by statute. In Staff's view, the collaborative process that occurs during the implementation phase, which includes feedback from suppliers, has resulted in a reasonable balance of risk between utilities and suppliers. While Staff generally prefers that stakeholders determine contract credit requirements during the implementation phase, Staff supports inclusion of the threshold recommendation in the Plan because, as implied by ComEd in its objections, ComEd is willing to change the collateral thresholds it has used for the past two years without offering any compelling reason for doing so. Staff also notes that in the prior procurement docket, ComEd did not object to specific collateral requirements for long-term renewable energy resources and RECs, including the types of security the utilities would accept to satisfy those collateral requirements.

ComEd's comparisons to the unsecured credit limits granted by either PJM or the New Jersey auction contracts ("BGS contracts") are inappropriate in Staff's opinion. According to Staff, exposure under ComEd's contracts is a mark-to-market calculation for all transactions under all existing contracts, which may extend up to three years from the date the parties execute the supply contracts. Staff explains that the $80 million threshold amount serves as a cap on unsecured credit limits granted to all affiliated parties and all contracts covered by a single guarantor. In contrast, Staff asserts that PJM calculates exposure as the sum of the highest three consecutive weekly bills in the past year and permits affiliates an aggregate unsecured credit limit up to $150 million. Staff says the BGS contracts grant a maximum unsecured credit amount of $60 million, but do not cap unsecured credit limits across affiliates or cap the aggregate unsecured credit limit for guarantors of more than one supplier. Finally, Staff states that some utilities' energy contracts grant credit worthy suppliers higher unsecured credit limits than ComEd. For example, Staff indicates that utilities in Maryland and Pennsylvania grant suppliers rated A- and above unsecured credit limits of $100 - $125 million.

As for ComEd's claim that allowing the Plan to implement overly generous unsecured credit levels would mean that customers will bear additional risks and additional costs, should a supplier default, Staff states that neither ComEd nor AIC has had a supplier default under the power supply contracts. Staff insists that there is no additional risk to customers due to supplier defaults today than existed for the past two procurement cycles. With regard to ComEd's claim that the IPA has failed to offer any support for the threshold level it proposes, Staff argues that the IPA has proposed nothing more than establishing in the Plan the same threshold level adopted in the previous procurement cycles.

Staff notes that ComEd also proposes to strike out the sentence on contract terms that states, “[u]nder 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.” Staff complains that ComEd does not provide a rationale for that deletion. In Staff’s judgment, omitting that language would be unwise given such actions would undoubtedly increase risk to suppliers because suppliers could not rely on the credit terms of the contracts they sign. An increase in supplier risk would lead to an increase in contract prices. Therefore, Staff urges the Commission to reject ComEd’s recommendation to delete the sentence that prohibits making retroactive changes to existing contracts. If, however, the Commission finds merit in ComEd's arguments, Staff recommends that at a minimum the Plan retain the language prohibiting retroactive changes to existing contracts. In Staff’s view, the language prohibiting retroactive changes would eliminate a potential risk factor that could prove very costly to customers.

3. IPA Position

The IPA disagrees with ComEd that the collateral threshold provision of the Plan deviates from the PUA. The IPA states that changes to the collateral threshold levels will not be done unilaterally, and as the Plan emphasizes, will only take place when there is consensus among the utilities, Procurement Administrator, Procurement Monitor, and Staff. The IPA commits to negotiating threshold levels as part of the contract terms and conditions negotiations, again along with the Procurement Administrator, Procurement Monitor, bidders, utilities, and Staff. Therefore, the IPA recommends that this portion of the Plan not be modified as ComEd suggests.

4. Commission Conclusion

As noted by ComEd, the Plan discusses collateral thresholds at page 16. The Commission understands the collateral threshold to be the contract value level above which a utility may require collateral from a supplier (depending on a supplier's credit worthiness). While Section 16-111.5(e)(2) of the PUA describes the development of standard contract forms and terms, the Commission does not view the IPA's collateral threshold proposal to be contrary to the PUA as ComEd suggests. ComEd itself interprets the PUA to permit the Commission to determine contract forms and terms and acknowledges that it has even supported such findings in the past. ComEd's attempts to distinguish the Commission's past adoption of contract terms from the current proposal are unavailing and in fact self serving.

The Commission understands that the language at page 16 of the Plan merely provides a starting point and notes that the IPA remains open to negotiating threshold levels with the Procurement Administrator, Procurement Monitor, bidders, utilities, and Staff. ComEd's suggestion that the collateral threshold levels in existing energy contracts are too generous compared to those employed by PJM and in the New Jersey auction process is not persuasive since it is not clear whether such comparisons are appropriate. But what is most troubling about ComEd's position is the recommendation that language barring changes to collateral thresholds in existing contracts be removed. To leave open the possibility of such changes is not appropriate and, as Staff suggests, unreasonably increases the risk to suppliers.

The Commission supports this limited and reasonable establishment of contract terms (to the extent that it can be considered as such) at the request of the IPA for purposes of this Plan. The Commission further notes that under Section 16-111.5(e)(2), if the Procurement Administrator and a utility were unable to agree on collateral threshold terms, the Commission would ultimately have the responsibility to decide the matter. To be clear, the Commission does not intend to make a habit of adopting language from a prior Plan without sufficient justification. The circumstances indicate, however, that doing so is warranted in this instance.

E. Short-Term REC Collateral Requirements

1. ComEd Position

ComEd notes that the Plan recommends that short-term (i.e., one year) REC contracts should include collateral requirements that equal 10% of the remaining contract value, and provide unsecured credit lines for credit worthy suppliers. ComEd states that while, in general, it is highly supportive of meaningful credit requirements for contracts in order to protect customers, ComEd does not believe that any collateral needs to be held for short-term RECs. In explaining its position, ComEd observes that Section 1-75(c)(1) of the IPA Act requires that a utility procure a certain percentage of renewable energy resources by June 1 of each planning year, i.e., June 1 through May 31. Once the utility has contracted to procure such amounts, ComEd claims there is no further statutory requirement that the utility procure any replacement RECs in the event that a supplier fails to deliver the contracted amount. Nor is there any requirement, ComEd adds, for a reconciliation or true-up to ensure that the utility has actually purchased the statutorily-required amount.

Whereas typically a utility would need to procure replacement product to meet customer needs and therefore be exposed to potentially higher prices for such replacement product, ComEd insists that is not the case here. Instead, ComEd claims that the only financial consequence for customers in this case would be that their costs would decrease due to fewer RECs being procured. ComEd recognizes, however, that if no collateral is required, suppliers may have an incentive to game the system by executing contracts they do not intend to honor if they are able to sell their RECs for a higher price elsewhere. To prevent this, ComEd recommends that the Commission provide that suppliers who default in their REC delivery obligation are ineligible to participate in any future REC or renewable energy resource procurement event.

For long-term (greater than one year) REC contracts, ComEd states that it seems clear that replacement RECs for future years would need to be procured either through a replacement long-term contract or future short-term REC procurements. Consequently, ComEd believes that meaningful credit requirements should be required for long-term contracts to protect customers as well as to prevent suppliers from gaming the system by executing contracts they know they can walk away from if prices move higher.

ComEd recommends that the last sentence of the Renewable Energy Resource section that appears on page 4 of the Plan be revised to read as follows:

> Therefore, the utilities' REC contracts should not require that any collateral be posted by either party. Instead, the IPA will not allow any supplier that defaults under a REC supply agreement to participate in future REC or renewable energy procurement events.

ComEd notes that the conclusion that no collateral requirements need be imposed on one year REC contracts is wholly premised on ComEd's understanding that, under the IPA Act, replacement RECs are not required to be procured. If the Commission determines that replacement RECs are required to be procured, then adequate collateral should be required to be posted by the suppliers in order to protect customers.

In its reply to the various responses to the comments, ComEd states that WOW, Staff, and the IPA appear to be willing to discuss this issue further. ComEd agrees that this issue is best left to further discussion among the parties. In order for the parties to discuss this further, however, ComEd asserts that the language in the Plan that seeks Commission approval for specific collateral requirements for short-term RECs needs to be deleted. Otherwise, ComEd reasons, the issue will have been decided and there will be nothing left for the parties to discuss. In addition, in order to enable the parties to properly address the amount of collateral for RECs for the 2011 REC procurement event, ComEd states that the parties need a Commission determination in this docket as to whether or not the procurement of replacement RECs is legally required in the event of a supplier default. Therefore, in its order, ComEd contends that the Commission should explicitly state that the language in the Plan describing the amount of collateral for RECs should be deleted because replacement RECs are not required to be procured and that, during the implementation phase of this procurement, the parties should discuss the appropriate amount of collateral to require in light of that decision.

ComEd notes further in its reply that WOW disagrees with ComEd's proposal that suppliers who default on REC contracts not be allowed by the IPA to participate in future REC procurements. WOW argues that this amounts to a penalty that is unenforceable under Illinois law. ComEd agrees that penalties in contracts may be unenforceable in Illinois. ComEd states, however, that it is not proposing this as a contract remedy. ComEd is recommending that the Commission and the IPA adopt this proposal as a part of their statutory responsibility to design, oversee, and implement a procurement process in Illinois and to establish the criteria and qualifications for bidder participation. Nevertheless, ComEd states that it is willing to discuss the appropriate remedy for supplier defaults on RECs along with other contract terms in the procurement implementation process led by the Procurement Administrator.

2. WOW Position

WOW contends that collateral is not needed for one-year RECs, but for reasons different from those of ComEd. Consequently, WOW reaches a different proposal for ensuring that Illinois utilities actually receive RECs. WOW expects one-year REC prices to be considerably lower in the 2011-2012 procurement than those awarded last year because the pool of potential bidders is expanding to include adjacent state resources as well as in-state resources (see Section 1-75(c)(3)) of the IPA Act). WOW states that average prices last year were in the range of $4 to $5 per REC. WOW claims that the administrative burden of the paperwork associated with collateral and the line of credit usually outweighs the benefit from a product of very low dollar amounts. In addition, WOW suggests that there would be administrative benefits to both sides if the collateral were replaced with something both could agree upon.

WOW understands ComEd's concern to be that given the low prices Illinois utilities will be paying for RECs next year, suppliers may have an incentive to incur the contract damages and sell RECs for a higher price elsewhere. WOW asserts that there is always risk that a contract will not be fulfilled, which is why Illinois courts allow parties to minimize their risk by including liquidated damages or collateral and federal courts have acknowledged the existence of efficient breaches. Regardless of the method used within the contract, WOW claims that the purpose of damages is to encourage/secure performance in a fair and reasonable manner in light of the anticipated or actual loss. ComEd's recommendation to bar a defaulting supplier from participating in future procurements is too extreme, in WOW's opinion; and amounts to a penalty (the death penalty for a supplier in Illinois) rather than a requirement that the REC purchaser be made whole.

Furthermore, WOW argues that ComEd's recommended penalty is unconscionable and unenforceable as a matter of public policy. WOW states that penalty provisions are generally frowned upon and Illinois courts have found them unenforceable. (WOW response to objections at 4-5 citing <u>American Nat. Bank & Trust Co. of Chicago v. Regional Transp. Authority</u>, 125 F.3d 420, 439-40 (7th Cir. 1997) (finding that damages for breach by either party may be liquidated in the agreement but only at an amount that is reasonable in the light of the anticipated or actual loss caused by the breach and the difficulties of proof of loss; a term fixing unreasonably large liquidated damages is unenforceable on grounds of public policy as a penalty.) and <u>Lake River Corp. v. Carborundum Co.</u>, 769 F.2d 1284, 1290 (7th Cir. 1985)) WOW suggests the best course of action is to allow the parties to discuss or negotiate a provision that would discourage breach of contract.

WOW therefore recommends that the Commission order the parties to discuss and agree upon mutually acceptable terms which would discourage them from defaulting on the contract. WOW relates that Section 16-111.5(e)(2) of the PUA provides the guidelines and identifies the participants for developing a standard contract form that follows the procurement plan approved by the Commission and meets generally accepted industry practices. Although not supportive of an effort by the Commission to decide contract terms in this context, if the Commission wishes to address this issue at this time, WOW offers an alternative. In the event of a default by the supplier of the RECs, WOW suggests that the supplier pay the utility the higher of (1) the value of that supplier's contracted REC or (2) the load weighted average winning REC price as posted by the Commission pursuant to Section 16-111.5(h), multiplied by the number of RECs that were the subject of the default. WOW asserts that this would be a fair and reasonable damages provision given its relationship to the actual costs incurred by the utility.

WOW also observes that ComEd interprets its responsibilities as not including any obligation to procure replacement RECs following a default. WOW believes this interpretation of the RPS runs headlong into it not being able to enforce a liquidated damages provision, and not being able to comply with the intent of the statute -- that RECs actually be purchased and possession taken by the Illinois utility. WOW suggests that a liquidated damages provision provides certainty and is not uncommon. WOW also believes that its proposal should address ComEd's concern of reducing a supplier's interest in selling RECs to other buyers and give money to the utility so it can purchase replacement RECs.

3. AIC Position

AIC recognizes that default by an energy supplier is a serious matter and that the utilities and their customers need to be protected from the potential for a repeat offense. Nevertheless, AIC contends that a life time ban appears to be extreme. AIC therefore suggests a solution whereby defaulting suppliers would not be allowed to participate in the procurement process for a period of two to three years following the offense.

4. Staff Position

Staff states that while it is true that nothing in the IPA Act requires replacement RECs, it is also true that nothing in the IPA Act prohibits replacement RECs. Regardless, Staff believes ComEd's proposal brings to light an important omission in the IPA Plan. Staff indicates that the IPA Plan does not specify what will occur in the event of a supplier default under short-term REC contracts. Therefore, Staff recommends that the Plan specify a contingency plan in the event there is a supplier default under a short-term REC contract.

Staff suggests that ComEd's proposal may be more appropriate than Staff's recommendation that ComEd REC contracts include the same collateral requirements as AIC REC contracts if the IPA Plan specifies that, following a REC supplier default, utilities are not required to purchase any replacement RECs or utilities are required to purchase replacement RECs in an amount that equals the remaining contract value for the defaulting REC supplier. In contrast, if the IPA Plan requires the utilities either to purchase replacement RECs using collateral on hand or to replace all RECs that were not provided due to a supplier default, then Staff believes its proposal would be more appropriate than ComEd's proposal. In Staff's view, the decision regarding contingency plans in the event of a REC supplier default involves a trade off between lower contract prices for RECs due to eliminating collateral requirements for REC suppliers and lower REC replacement costs should a REC supplier default. Staff recommends the IPA evaluate the costs and benefits associated with the possible outcomes of this tradeoff and provide a contingency plan for the Commission to approve or modify in the Plan.

Staff does not support WOW's primary recommendation that the Commission order the parties to discuss and agree upon mutually acceptable terms to discourage parties from defaulting on a contract. WOW's alternative proposal for substituting collateral requirements with a liquidated damages provision, however, intrigues Staff because it could potentially balance the risk allocation between the utilities and REC suppliers in a manner that minimizes costs incurred by customers. Staff therefore recommends that the Plan be modified to allow stakeholders the opportunity to vet WOW's alternative proposal for liquidated damages as well as other credit requirement proposals that may minimize costs ultimately incurred by customers relating to the utilities' one-year REC contracts. Furthermore, in recognition of the IPA's goal of harmonizing the utilities' one-year REC contracts, Staff states that any alternative credit requirements should be acceptable to both utilities in order to unify the credit requirements for one-year REC contracts to the maximum extent possible. Specifically, Staff recommends adding to page 4 of the Plan, ". . . unless an alternative proposal is acceptable to the procurement administrators, the utilities, the IPA, Commission Staff and the procurement monitor." Even if the Procurement Administrator can not agree on an alternative approach to credit requirements, Staff maintains that this language would require uniform collateral requirements for the utilities that are less costly to suppliers than the collateral requirements included in ComEd's current one-year REC contracts. Moreover, Staff believes that this language would comport with the process described in the IPA response to ComEd's objections.

5. IPA Position

The IPA commits to negotiating short-term REC collateral requirements and other contract provisions as part of the contract terms and conditions negotiations. Such negotiations will include the Procurement Administrator, bidders, utilities, Staff, and the Procurement Monitor. Therefore, the IPA recommends that this aspect of the Plan not be amended as sought by ComEd.

The IPA, however, agrees with Staff that the Plan and the contract terms should incorporate contingencies and terms that will permit ComEd and AIC to satisfy the RPS adopted under prior and future procurement events, where a supplier defaults on a short-term REC contract. In its reply to the various responses to the objections to the Plan, the IPA proposes that in the event of a supplier default, ComEd and AIC purchase replacement RECs using collateral on hand from the defaulting supplier when the defaulted volume represents more than 5% of the total number of RECs that were secured for that compliance year. If the defaulted amount is less than 5% of the total number of RECs that were secured for that compliance year, the IPA proposes that the vendor surrender the collateral, but that the utility need not replace the REC volumes. The IPA also suggests that it conduct any procurement required to replace the short-term RECS.

6. Commission Conclusion

Page 4 of the Plan discusses renewable energy resources. As an initial matter, the Commission disagrees with ComEd's interpretation of the IPA Act that there is no need for a utility to replace short-term RECs in the event that a supplier fails to deliver the contracted amount. Such an interpretation conflicts with the underlying intent of the statute that RECs actually be purchased and possession taken by the Illinois utility. Failure to deliver by a supplier does not absolve a utility of its RPS obligations when alternatives exist.

In addition, the Commission finds ComEd's proposed exile of a supplier to be too extreme in the event of a default. While performance under any contract is to be encouraged, barring a defaulting supplier from providing RECs in the future may cause more harm to customers in the long run than the harm caused to customers by the default . A less extreme but still meaningful alternative must be identified.

Staff recommends that the Plan be modified to allow stakeholders the opportunity to vet WOW's alternative proposal for liquidated damages as well as other credit requirement proposals that may minimize costs ultimately incurred by customers relating to the utilities' one-year REC contracts. Staff further suggests that any alternative credit requirements should be acceptable to both utilities in order to unify the credit requirements for short-term REC contracts to the maximum extent possible. To the extent that any such damages/credit requirements are designed to replace the required missing short-term RECs, the Commission finds this proposal reasonable. The Plan should be modified to provide for the implementation of this solution in accordance with Section 16-111.5(e)(2).

In addition, if a new RFP must be issued, the Commission considers it appropriate for any replacement short-term RECs to be procured by the IPA. The IPA's contingency plan for supplier defaults exceeding 5% of the RECs secured for the Plan year, however, is perhaps too vague. Specifically, the proposal fails to deal with several issues of timing. For instance, at what point in time does the IPA plan to hold these procurement events (multiple times per year, once per year, at the next regularly scheduled REC procurement event)? What vintage RECs would be procured? If the default is not even detected until after the relevant Plan year, will the IPA try to procure RECs under the previous year Plan or the current Plan? Finally, if the contract defaulted upon was for both energy and RECs, should the IPA seek to replace both or just the RECs. To what extent (if any) should options be written into contracts to allow for non-faulting suppliers to make up for defaulting suppliers' quantities? Because the

IPA's contingency plan fails to address these questions (and perhaps others that have not occurred to the Commission), the Commission is reluctant to approve the IPA's contingency plan for replacing RECs. Furthermore, the Commission sees no urgency to deal with this issue. There is no evidence that there have been any REC supply deficiencies due to supplier defaults, to date. Hence, rather than approve the IPA's contingency plan, the Commission suggests that the IPA develop a more detailed proposal and include it with next year's procurement Plan.

F. Oversubscription

1. ComEd Position

Both of the prior Plans included a 10% increased purchase volume for the peak periods in the months of July and August. The pending Plan includes the same requirement. ComEd argues that the continued inclusion of the 10% oversubscription in July and August is unsupportable, risky, and should be removed.

Using the IPA's own methodology, ComEd states that it assessed whether the risk associated with weather driven price spikes in the summer would be reduced by purchasing more than 100% of expected monthly requirements for peak periods in July and August. According to ComEd, the first step in this process was to determine the average portfolio energy cost assuming a high case (spot prices +40%, spot load +10% for July and August) and a low case (spot prices -30%, loads -8% for July and August). ComEd then analyzed three situations where purchases were made at 110%, 120%, and 130% of July and August peak loads. ComEd states that no correlation was assumed between spot prices and gross-up factors consistent with historical monthly data.

ComEd graphically provides the results of this analysis and contends that it shows the weakness of any argument for over-hedging in July and August. According to ComEd, this is due to the fact that market prices are low, and even with 40% price stress, the cost of spot market purchased power will be below the average embedded portfolio cost. ComEd contends that even without the benefit of the extra 10% hedge, the average portfolio cost will drop in the high case. ComEd argues that procuring more energy than is forecast to be needed during summer months, while hedging against higher than expected loads and prices, adds additional risk to the portfolio on balance.

ComEd maintains that historical experience underscores the likelihood that this approach will add cost. ComEd states that while it may pay off in some years, to date the over-hedging gamble has increased consumers' costs by $1.6 million since the 2008 procurement. Reproduced below is a table that ComEd says contains the outcome of each year's over-procurement.

July/August	Excess Purchased (MWh)	Weighted Avg. RFP Price ($/MWh)	Weighted Avg. Peak Price ($/MWh)	Benefit/(Detriment)
2008	96,480	94.79	86.42	($807,538)
2009	316,800	43.3	32.39	($3,456,288)
2010	446,400	49.8	55.68	$2,624,832
Total	859,680			**$ (1,638,994)**

In its consideration of the last procurement plan in Docket No. 09-0373, ComEd observes that the Commission approved 10% oversubscription cautiously, noting both the lack a rigorous analysis supporting it and that the data showing increased costs was still limited. Once again, ComEd argues that there has been no rigorous showing of any benefit for this over-hedging. According to ComEd, both rigorous prospective analysis and the weight of actual data point to the riskiness and expense of this strategy. Given the volatile nature of prices and loads, ComEd continues to recommend that 100% of expected requirements are purchased for all periods of the current plan year. ComEd believes there is no reason to go beyond this.

2. IPA Position

In support of its position, the IPA maintains that the potential for spikes in consumption in the portfolio are greatest during the July and August peak periods. The IPA contends that oversubscription by 10% will mitigate weather risk associated with this period. The IPA concedes that prices in the current market are relatively low, but insists that future spot prices can be far above current future prices due to variables in plant outages, transmission constraints, natural gas prices, and evidence of growing economic recovery. The IPA notes that the Commission approved oversubscription as a hedge to price risk in the prior Plan in Docket No. 09-0373. The IPA urges the Commission to be consistent with its prior Orders.

3. AG Position

In its Brief on Exceptions, the AG argues that the IPA has provided sufficient justification for its 10% oversubscription proposal. The AG contends that ComEd's analysis amounts to simply a few meaningless data points. The AG urges the Commission to defer to the IPA's judgment in the interest of protecting customers.

4. Commission Conclusion

At pages 28 and 45 of the Plan, the IPA references its proposal for AIC and ComEd, respectively, to include a 10% oversubscription for the peak periods in July and August. The Commission appreciates the IPA's effort to ensure that customers will have sufficient power during peak periods. In the last procurement docket, the

Commission deferred to the IPA's judgment on this issue even in the absence of analytical data supporting 10% oversubscription. In that docket, however, the Commission also advised the IPA that quantitative analysis on this issue would be useful if the IPA sought to continue this practice. Specifically, the Commission found that, "performance by the IPA of a quantitative analysis on the hedging issue in preparation of its next filed Plan would be beneficial to the assessment of this issue." (Docket No. 09-0373 at 160) Unfortunately, the IPA did not heed this advice and provided no analysis in support of the 10% oversubscription proposal.

ComEd, on the other hand, has provided an analysis utilizing historic data for the past three years. In 2008, when the utilities developed their own procurement strategy before the IPA was organized, 10% oversubscription unnecessarily cost ComEd customers $807,538. In 2009, 10% oversubscription unnecessarily cost ComEd customers $3,456,288. In 2010, 10% oversubscription saved ComEd customers $2,624,832. Altogether, 10% oversubscription unnecessarily cost ComEd customers $1,638,994. What the Commission gleans from this information is that a 10% oversubscription in the months of July and August does not necessarily benefit customers.

While the possibility of sometimes "winning" and sometimes "losing" is an inherent part of any hedging measure, the Commission is hesitant to continue relying on the IPA's recommendation on this issue without any quantitative analysis demonstrating the likelihood of benefits to customers. Many variables are present in any such analysis, and the Commission recognizes that the results would be far from perfect. But here, the IPA has neglected to provide any quantitative analysis to support its proposal despite being advised to do so in Docket No. 09-0373. In the absence of any such analysis to rely upon, the Commission finds that 10% oversubscription in the peak periods of July and August is unwarranted and directs that the Plan be modified to reflect this conclusion. The IPA is free to make this proposal in future Plans but is again cautioned to provide some quantitative support if it chooses to do so.

G. Energy Hedges - Financial Swaps v. Physical Transactions

1. AIC Position

AIC understands the Plan to state that the IPA will procure physical transactions at least for the 2011 procurement process and will monitor developments and make on-going recommendations in future procurement years. AIC supports the transition from financial swaps to physical transactions (described on page 32 of the Plan) due to uncertainty surrounding the outcome of the Federal rule making process for recently passed derivative legislation. AIC recognizes that the rule making may adversely impact it and/or its customers. On page 27 of the Plan, however, AIC claims that the IPA provides a contradictory proposal by stating that the Procurement Administrator can make a decision during the 2011 procurement process between (1) physical transactions and (2) financial transactions that can be contractually converted from physical transactions. At a minimum, AIC urges the IPA to correct this contradiction.

But if given the choice, AIC prefers the language on page 32 of the Plan because it is the most conservative course of action given uncertainty in the rule making process and it removes any doubt as to what methodology would be used in the 2011 procurement process.

2. IPA Position

The IPA acknowledges AIC's concern that the Plan is contradictory in that it provides that the Procurement Administrator will have the discretion to revert back to financial swap contracts if deemed preferable to physical delivery of energy. The IPA maintains that the option of reverting back to a financial swap contract should be kept open in the event that clarity on the derivatives issue is achieved prior to procurement events. In addition, the IPA recommends the following amendments, which may alleviate some of AIC's concerns:

> On pages 27-28:
>
> 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 be instructed to fashion the swap contract, ...
>
> On page 32:
>
> In summary and in light of the information currently available, the IPA recommends replacing financial swaps for the spring 2011 procurement event 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 2011 as the outcome of the current rule making process becomes clearer.

3. Commission Conclusion

The Commission understands that the IPA wants to keep its options open in this context if the forthcoming derivative rule leaves financial swaps as an attractive option. The Commission finds this position reasonable. The language that the IPA proposes for pages 27-28 and 32 of the Plan will help clarify the matter and is approved. If necessary, however, the Commission directs that substantively similar modifications be made to the Plan as it pertains to ComEd.

H. Exchange Traded Contracts

1. AIC Position

AIC understands the Plan to offer three methods by which it could execute contracts: 1) ISDA agreements for financial instruments such as fixed-for-floating swaps, 2) an EEI agreement for physical products and, 3) central counterparty clearing for standardized financial instruments on exchange traded contracts. While the first two methods have been approved in previous Plans, AIC relates that the third method represents a new option. Because AIC does not believe that the IPA has adequately described the process changes necessary to allow for clearing of transactions on exchanges, AIC recommends that the third method be eliminated from the Plan.

Specifically, it is unclear to AIC if the solicitation process would still include an RFP as has been done in past years or whether an exchange clearing represents a process change away from the RFP process. If so, AIC claims such a proposal has major ramifications that should be fully vetted. Assuming the IPA intends to continue to use the RFP process, AIC could envision a scenario where winning suppliers work in concert with the IPA, the Procurement Administrator, AIC, and an exchange to set up a pre-defined transaction for clearing on the exchange. Under such a scenario, AIC states that the non-price contract terms would be defined as part of the IPA RFP process and would be in the form of an ISDA or EEI contract. AIC asserts that a standardized form of an exchange traded contract would not include the product specific contract language that is required for an IPA procurement event. AIC states that the IPA proposal, which AIC supports, is for it to procure physical products during the 2011 procurement cycle. AIC contends that under a scenario where AIC procures physical products, an exchange cleared product adds no value to the process and potentially adds costs to consumers. If, however, the Commission determines that central counterparty clearing should be included in the Plan, AIC indicates that the Plan should specifically state the IPA's intent to only allow the utilization of standardized financial instruments on exchange traded contracts when they meet the specifications, credit, and delivery requirements, which AIC interprets to mean that they will meet all of the non-price terms of the IPA procurement process.

2. Staff Position

In Staff's view, AIC presents a cogent critique of the IPA's proposal to add central party clearing for standardized financial instruments on exchange traded contracts. Staff understands AIC to argue that the IPA proposal has not been adequately defined, and that on the one hand, it may be inconsistent with the RFP process described in the PUA (which would have major ramifications that should be more fully vetted) while on the other hand, it may add nothing (or only additional costs) relative to AIC's preferred procurement of physical products during the 2011 procurement cycle. Staff is convinced that AIC's arguments present reasonable grounds for further study of central party clearing for standardized financial instruments on exchange traded contracts, which Staff would urge the IPA to undertake. In particular, Staff states that it is the type of procurement mechanism that might be clarified through discussions with the Procurement Administrator, Staff, the utilities, and the relevant exchanges and clearing houses. Staff urges the IPA to initiate such discussions well in advance of next year's Plan. Afterwards, in 2011, Staff urges the IPA to present its investigative findings and any associated recommendations along with the next procurement Plan.

3. IPA Position

The IPA disagrees with AIC's recommendation to eliminate central counterparty clearing for standardized financial instruments on exchange traded contracts as a method to execute contracts. If central counterparty clearing meet the specifications, credit, and delivery requirements, then the IPA believes those offers should be allowed. Therefore, the IPA recommends that the Plan not be modified as suggested by AIC.

4. Commission Conclusion

Page 16 of the Plan identifies the three methods by which contracts can be entered into as a result of the procurement process. As noted by Staff, AIC raises some legitimate questions regarding the implementation of central counterparty clearing for standardized financial instruments on exchange traded contracts. The comments of AIC and Staff raise concerns for the Commission. The IPA's response to those comments has done little to allay the Commission's concern. Although the IPA's proposal may be a very good one, without more of an explanation of how central counterparty clearing on exchange traded contracts would actually work in conjunction with the various statutory requirements, the Commission is not inclined to approve it. Accordingly, the Commission directs that the Plan be modified to remove this method of contract execution. The IPA is free to renew this proposal in future Plans, but the Commission advises the IPA to provide an explanation of how its proposal would work and what the potential advantages are over the other two methods of executing contracts.

I. Optional Procurement Events

1. ComEd Position

The Plan authorizes the IPA to procure up to an additional 10% of portfolio requirements when market prices fall 10% below the average weighted price of existing supply agreements and below the price of supply from the most recent procurement event. According to ComEd, the IPA presents no analysis or justification in support of this proposal. In ComEd's view, this lack of support contrasts with the well documented analysis supporting the Plan's three-year laddered procurement strategy. ComEd asserts that analysis demonstrates that procuring energy relatively evenly over a three-year period presents the lowest price risk scenario. ComEd contends that the Plan makes no attempt to explain how procuring an additional 10% improves upon it.

Without any such analysis, ComEd fears that procuring an additional 10% of supply will increase price risk and not lower it.

In addition, ComEd claims it is unclear how the proposed additional procurement would work in practice as it takes months to run a fair and transparent RFP process. Furthermore, ComEd observes that the IPA does not explain how the process would react to changing market conditions. For example, if the IPA sees forward prices below its benchmarks and starts the incremental RFP, ComEd wonders if the IPA would then have to cancel the RFP if forward prices then increase above the benchmark. If the RFP is cancelled, ComEd asks who bears the costs of this failed RFP.

2. Staff Position

Staff disagrees with the IPA's proposal to engage in optional procurement events. In Staff's view, the proposal does not mitigate the risk of price decline as the IPA suggests. According to Staff, a price decline only poses a risk if the utility is hedged beyond 100% of its requirements. Staff also contends that it is not entirely clear what is meant by the phrase, “such prices are below the prices for the most recently completed planning year procurement event.” (Plan at 17) Staff finds the phrase ambiguous for two reasons. The first reason is that each procurement event generally results in the purchase of several contracts with a range of prices covering the same delivery period. It is unclear to Staff if the IPA’s proposal that the trigger be when the “market indices” (which are generally considered to be averages of current market prices) are below (1) the minimum, (2) the maximum, or (3) the average contract prices obtained in the most recent procurement event. The second reason that Staff finds the phrase ambiguous is that the plan is generally focused on finding combinations of contracts to cover 24 time periods per year (defined by month and on-peak versus off-peak sub-periods). A given time period may be covered by several different types of contracts. For example, Staff suggests July 2012 on-peak might be covered by a combination of July 2012 on-peak, July-August 2012 on-peak, and July 2012-May 2013 on-peak contracts. Staff says it could also include July 2012 ATC, July-August 2012 ATC, and July 2012-May 2013 ATC contracts. Staff claims each of these contracts can have very different market values.

To the extent that the proposal would lead to more than the otherwise planned additional 35% of expected load being hedged for each of the last two years covered by the Plan, Staff suggests that the planned hedging levels may already be too high if the contracts entail substantial risk premiums. In this regard, Staff notes that NYMEX futures prices for latter-year electricity contracts have been considerably higher than for early-year contracts. Whether this is evidence of substantially higher risk premiums for latter years may be difficult to assess, but Staff believes that such should be considered by the IPA, and should lead to more caution about expanding the degree of long-term hedges.

While it is unclear to Staff just how many of these incremental procurement events might be held under the IPA’s proposal, Staff believes that each such event would add considerable costs to the entire procurement process. Such costs are in the form of time and money spent for a Procurement Administrator and Procurement Monitor and by the Commission, Staff, and utilities. Staff is particularly concerned that the IPA itself does not have the time and resources available to pursue “optional” activities. For reasons that continue to elude Staff, the IPA generally hires Procurement Administrators several months beyond the planned dates presented in the procurement plans. This past performance raises doubts in Staff’s mind about the IPA’s ability to handle the additional responsibilities associated with this and other new proposals. Staff recommends that the IPA remove all the above-cited portions of the Plan dealing with optional procurements and incremental procurement events.

3. IPA Position

In response to the objections of both ComEd and Staff, the IPA asserts that neither cites to a provision of a statute that limits procurement cycles to once a year. While its proposed optional incremental events may not be frequently used, the IPA believes eligible retail customers may benefit where more frequent procurements result in a lower price for energy. In the IPA's view, this option should also remain open should future procurement plans move towards a multiple or continuous procurement cycle – an issue that the IPA sought additional comment on for future consideration. Therefore, the IPA recommends that no changes be made to this aspect of the Plan. The IPA does not specifically address Staff's concerns about the IPA's ability to manage such optional activities.

4. AG Position

In its Brief on Exceptions, the AG asserts that given the recent market price decreases and the General Assembly’s goal that the IPA obtain electricity supply at the lowest cost over time, it is reasonable for the IPA to include optional procurement events in its Plan so it might capture declining prices. The AG states that the Plan calls for the “authorization of the Commission” for such procurements to occur and limits participation to bidders qualified in, and the terms and conditions agreed to in, the Spring 2011 solicitation. (See Plan at 17) The AG contends further that how the optional procurements would work is clear from the Plan. The AG also argues that the IPA is capable of conducting such optional procurements along with its other responsibilities.

5. Commission Conclusion

Page 17 of the Plan describes the IPA's proposal for optional energy procurement. The Commission appreciates the IPA's interest in keeping costs low for customers, but has some concerns with this specific proposal. As ComEd notes, it is unclear how the proposed additional procurement would work in practice as it takes months to run a fair and transparent RFP process. Furthermore, if the IPA sees forward prices below its benchmarks and starts the incremental RFP, the Commission wonders if the IPA would then have to cancel the RFP if forward prices then increase above the benchmark. If the RFP is cancelled, the Commission also wonders who bears the costs of this failed RFP.

Additionally, the Commission questions the IPA's wisdom of taking on additional responsibility at this time. Organizing and implementing procurement events require many resources and a great deal of attention. As is clear from the record, the Plan approved in Docket No. 09-0373 has not yet been fully implemented. Given this fact and the many concerns about the process for securing renewable energy under the prior Plan, the Commission is hesitant to authorize the IPA to take on additional work. The Commission agrees with the IPA that nothing in neither the IPA Act nor the PUA limit or restrict the type of optional procurement events described in the Plan, but the Commission is not prepared to agree to a Plan that would divert the IPA's attention from the main task at hand at this time. The IPA is welcome to propose such optional procurement events in future Plans that clearly set forth the potential benefits to be derived there from and demonstrate that the IPA has sufficient resources to undertake such efforts. Accordingly, the Commission directs that the Plan be modified to remove those portions addressing the optional procurement events.

J. Multiple Procurement Cycles

1. RESA Position

RESA supports the concept of introducing more frequent procurement events as one of several possible procurement approach modifications that can result in more market responsive and market reflective default service. Although the Plan discusses the possible value of moving toward multiple procurement cycles, RESA complains that the Plan makes no real progress toward doing so. RESA nevertheless commends the IPA for requesting comments from other parties in response to RESA's comments, which RESA interprets as the IPA's intention to address this matter in this proceeding.

According to RESA, generally, utility default service procurement should result in market reflective price signals. RESA asserts that continued progress toward a competitive electric market is the best way to help all consumers balance price risk and budget certainty while also providing innovative and customer-driven value-added services. RESA contends that successful retail competition will produce downward pressure on price, offer a variety of product options for end-use customers, increase conservation incentives, enhance customer service, improve environmental management, and hasten the introduction of new, innovative products. RESA argues that retail energy competition requires that default service pricing be properly structured; consumers must see a default price for electricity that reflects the actual market price of the electricity they consume.

RESA contends that the failure of long-term procurement contracts to reflect current wholesale market prices create inefficiencies in either direction. In the event that a utility's procurement costs are higher than those available in the wholesale market, then RESA says customers are harmed by having to pay higher prices. RESA asserts that in the event that wholesale market prices rise above the locked in utility costs, customers will receive the incorrect price signal that energy is less expensive than reality and potentially over-consume and face the risk of rate shock as those contracts end. In either case, RESA believes customers will be harmed.

RESA argues that the use of more frequent procurement events would enable the procurement of shorter-term contracts which could be procured closer in time to actual delivery of the supply. According to RESA, the use of such contracts will enable customers to see a default price that better reflects market prices and will minimize long-term contract hedging premiums that are associated with longer-term contracts procured far in advance of delivery. In RESA's view, better price signals will spur more thoughtful efficiency investments, wise energy usage, and spur development of the competitive market. Better accuracy reduces customer costs over the long-term. RESA believes a major benefit of having default prices reflect the market is that consumers who are on those default rates will be sent clearer price signals that, in turn, will cause more efficient energy usage.

In an effort to facilitate discussion of this matter, RESA provided PPL Corporation's ("PPL") Modified DS Program Product Procurement Schedules for the Residential Customer Class and the Small Commercial and Industrial Class. According to RESA, these schedules depict a laddered procurement approach that PPL is using for its default service solicitations in Pennsylvania. Rather than procure a large amount of supply all at once, far in advance of the actual delivery term for the contract, RESA explains that the PPL procurement approach relies on quarterly procurement of varying term contracts. In RESA's view, this approach results in a significant percentage of supply "refreshing" with market prices each quarter as the underlying contracts expire and are replaced with new contracts. While RESA would ultimately support a procurement plan that relies on predominantly shorter-term procurement instruments such as fixed priced contracts less than one year in duration and spot market purchases, RESA believes the PPL approach provides an example of a procurement plan that produces a laddered, stabilizing effect on prices, while also resulting in default service prices that track changes in the market.

In the event that more frequent procurement events are not adopted in this proceeding, RESA suggests that a definite structure and timeline be put in place toward that goal. In addition to soliciting written input from parties, RESA suggest that Staff conduct workshops, beginning in January 2011, after the close of this proceeding, on the subject of multiple procurement events. If consensus can not be reached, RESA states that Staff should make a recommendation to the IPA well in advance of the IPA's submission of next year's Draft Plan so that the IPA can give timely consideration to the inclusion of multiple procurement events in that Plan.

2. ComEd Position

ComEd does not believe that having many or continuous procurements would enhance the procurement process as RESA suggests. ComEd notes that there are costs to holding procurement events and it is doubtful that these costs would be offset by consumer benefits when holding numerous such events in a year. In addition, given the existing significant duties of the IPA in relation to the annual energy procurement event, the annual renewables procurement event, the long-term renewables procurement event, the numerous requests for workshops to be hosted by the IPA, and the very limited resources currently at the IPA's disposal, ComEd can not support the IPA taking on additional procurement events at this time.

ComEd claims further that RESA's objection lacks the specificity required to understand how its proposal for more frequent procurement events might be incorporated into the Plan. To properly assess such a proposal, ComEd contends more information is needed regarding such issues as the frequency of the proposed procurement events and lengths of contracts, along with how the costs associated with more frequent events could be mitigated. Even then, ComEd does not see how moving to continuous procurement with the resulting volatility in energy prices benefits customers or is consistent with the direction in Section 16-111.5(d)(4) of the PUA to seek price stability.

3. Staff Position

Staff does not necessarily oppose the concept of introducing more frequent procurement events or reducing how far into the future energy price hedges are established. Before doing so, however, Staff believes that the IPA should investigate any disadvantages that might accompany such action. Staff suggests that holding more frequent events could reduce the amount of supplier participation and the degree of competition per procurement event. Additionally, Staff is concerned that more frequent procurement events would increase administrative costs and burdens. Staff believes that the latter problem is exacerbated by the PUA's requirements that each procurement event utilize an RFP, a Procurement Administrator and a Procurement Monitor (each of whom are required to submit reports to the Commission), utility and Staff involvement, and specific Commission approval following each event.

Additionally, Staff fears that RESA's proposal to reduce how far into the future energy price hedges are established would expose customers to greater risk of price volatility, since nearer-term forward prices are more volatile than more distant-term forward prices. Staff adds that while, as RESA claims, contracts that extend out only a few months may result in tariffed prices that are more reflective of market prices, that same benefit could be produced by reducing the hedge ratio below the IPA-proposed 1.0 (and 1.1 for July/August on-peak). Alternatively, Staff claims it could be obtained simply through changes in rate design. Finally, if, as RESA claims, contracts that extend out only a few months would reduce premiums associated with longer-term contracts, Staff suggests even more significant savings could be obtained by reducing or eliminating the procurement of contracts that extend one and two years beyond the plan year (as well as by reducing the hedge ratios for the plan year), without altering the number of procurement events per year.

Staff asserts that current electricity future contract prices increase in relation to the immediacy of their delivery periods and that this potential evidence of risk premiums should be investigated by the IPA and considered when it proposes hedging levels. Staff maintains that while it is not necessarily opposed to procurement plans that would be more sensitive to short-term price fluctuations and less heavily hedged, Staff finds RESA's proposal in this regard too complex and costly to administer. Hence, Staff recommends that the Commission reject RESA's recommendations for inclusion in the instant Plan.

Staff says it is willing to work with the IPA, RESA, and other interested parties in developing other proposals for potential inclusion in future procurement plans. In particular, Staff suggests that the Commission's ORMD solicit written input on this matter, and Staff will prepare a report to be provided to the IPA prior to the publication of the IPA's next draft procurement plan. Staff states that this report will include explicit recommendations on how, if at all, Staff would propose to "enable customers to see a default price that better reflects market prices and will minimize long term contract hedging premiums that are associated with longer term contracts procured far in advance of delivery," as RESA put it.

4. Commission Conclusion

Providing customers with more accurate information regarding the actual cost of electricity is certainly a reasonable goal, but the Commission is concerned that using multiple procurement events to achieve this and other goals described by RESA is not appropriate at this time. As it stands, the record lacks any analysis of the disadvantages versus advantages of multiple procurement events. Staff raises legitimate concerns about whether holding more frequent events could reduce the amount of supplier participation and the degree of competition per procurement event. Administrative costs and burdens may increase as well. Therefore, until a proper analysis of advantages and disadvantages is complete, the Commission is reluctant to support multiple procurement events.

The Commission is also troubled by this proposal for an additional reason. As discussed elsewhere in this Order, the IPA is still attempting to complete the procurement set forth in Docket No. 09-0373. The Commission is not inclined to direct the IPA to conduct additional procurement events beyond what is necessary when it would appear be having difficulty (for whatever reason) implementing the last Plan. Moreover, it would be premature to require workshops in January 2011 to discuss multiple procurement events in light of the difficulties with the last Plan. Staff, including the ORMD, and others are free, however, to meet without being directed to do so by the Commission to discuss proposals for multiple procurement events in future Plans.

K. Full Requirements Products

1. CECG Position

In order to procure supply required to meet the needs of eligible retail customers, CECG believes that the Plan should be modified to use full requirements products. CECG states that the IPA is given discretion to procure products individually, or in combination. Because the shape and quantity of the load is not known, CECG points out that customers bear greater risk with separate block products--a fact that the IPA should consider, according to CECG. CECG also opines that the benefits offered by a full requirements approach have never been greater than they are apt to be in this upcoming procurement cycle due to the likelihood that the number of utilities' bundled customers and underlying load will be reduced, potentially dramatically. CECG claims that the advent of purchase of receivables/utility consolidated billing, an increasing number of ARES indicating an interest in serving residential and small commercial customers, and the development of various websites and referral programs support the notion that competitive electricity markets will continue and strengthen, and that eligible retail consumers currently served through the IPA portfolio may migrate towards ARES options. CECG also agrees with the IPA that these recent developments indicate that significant reductions to the barriers to retail competition in residential markets are on the near-term horizon and that the portfolio is exposed to load uncertainty risk.

In terms of risk, CECG contends that it is important to keep in mind that costs to customers may include not only the prices paid by customers for IPA-procured supply, but the risks and lost opportunities they may face under a particular IPA plan. CECG argues that a full requirements approach will limit risk to customers by shifting risk from the IPA, ComEd, and AIC to wholesale suppliers, while promoting opportunities for customers by providing well-defined, competitively-procured default service supply that provides appropriate benchmarks for comparisons to RES product offerings. CECG indicates that risks to ComEd and AIC are essentially risks to their customers since the utilities pass the risks that they face onto their customers.

To demonstrate the value of shifting risk to the supplier, CECG offers an example concerning the Wellsboro Electric Company ("Wellsboro"), a Pennsylvania utility procuring its default service requirements through a managed portfolio approach. CECG relates that Wellsboro faced a market "surprise" and sought permission from the Pennsylvania Public Utility Commission on January 30, 2008 to recover more than $2 million in additional congestion costs from its customers because of an unexpected congestion event. CECG states that Wellsboro's customers did not have the "insurance" provided by a full requirements supplier for such an event and, as a result, had to bear the burden themselves for the rise in costs, as the Pennsylvania Public Utility Commission approved the pass through of such costs on February 28, 2008.

CECG contends that an IPA plan relying on full requirements products provides a proper balance by obtaining the most competitive prices for consumers, while appropriately placing risks such as volume risk on wholesale suppliers. In support of its position, CECG relies on a study of Pennsylvania's energy future by Dr. Susan Tierney, an energy policy expert, former Assistant Secretary for Policy at the U.S. Department of Energy, and former Commissioner at the Massachusetts Department of Public Utilities. CECG asserts further that through competitive full requirements procurements, wholesale suppliers bring many benefits because of their abilities and skills. Such abilities and skills, CECG points out, include expertise and ability to appropriately utilize load data to manage portfolios of supply at the least possible cost. CECG adds that suppliers are able to draw from their substantial experience throughout PJM, MISO, and other jurisdictions to develop proprietary models of customer behavior and switching patterns, to refine these models, and to better analyze the local data provided by utilities. CECG states that these wholesale suppliers pass on the efficiencies they achieve due to their sophisticated risk management skills and experience in the form of more competitive bids for full requirements products in competitive procurements. CECG claims that wholesale suppliers have already invested in, and continue to make significant investment in acquiring, experts in each specific type of market which makes up full requirements supply.

Speaking of its own experience and abilities, CECG states that it has hundreds of employees involved in the process of providing full requirements service to utilities and customers around the country, serving tens of thousands of MW of various types of full requirements load from coast to coast. CECG asserts that it employs a team of seasoned portfolio managers for large regional portfolios that serve its customers' full requirements loads. CECG says that it must ensure that any transaction that goes into its entire portfolio of obligations is accounted for at the end of each day, and that requirements for the entire load are met continuously for every hour of every day of every week. CECG further claims that a team of strategists continuously develops and improves computer models to keep track of all of the variable inputs that go into providing full requirements service; these strategists provide and analyze various scenarios that CECG's portfolio managers may face. In addition, CECG says a fundamentals group constantly researches basic supply and demand in fuel and power markets in order to monitor macroeconomic trends that affect the costs of serving load. CECG adds that a 24-hour power trading desk trades power in the hour-ahead, day-ahead, and week-ahead markets each day of the week, in order to help manage CECG's supply portfolio. CECG reports that power managers and traders monitor and trade in not only the PJM and MISO markets, but also those in New York, New England, and other markets throughout the U.S.; fuel managers do the same as fuel markets have direct effects on power markets. CECG claims that similar resources focus on fuel oil, natural gas, coal, currency, emissions, and renewable energy markets. CECG asserts that full-time meteorologists on its team continually monitor and predict the weather, so that its team can plan for weather effects on load requirements, and adjust supply accordingly. CECG states that the task of meeting full requirements load supply additionally requires controllers, schedulers, and dispatchers. CECG claims that supporting all of these operations is a team of regulatory specialists and attorneys that monitor and participate in regulatory and legal activities which affect energy markets.

CECG asserts that it is important to point out certain significant results from a recent analysis ("2010 Procurement Structure Analysis") conducted on behalf of Narragansett Electric Company d/b/a National Grid ("National Grid"), and filed in the Rhode Island Public Utilities Commission's proceeding to consider National Grid's procurement structure for Standard Offer Service, Rhode Island's equivalent of utility supply service to eligible retail customers. CECG contends that the 2010 Procurement Structure Analysis provides an important and unique technical assessment based on advanced modeling, to compare and contrast the relative costs and risks of different approaches to serve mass market customers, and how different approaches could impact customers' supply rates. CECG states that while the analysis suggests that a managed portfolio approach may, in fact, generally be cheaper than a full requirements structure, it is cheaper only by the narrowest of margins – roughly only $0.72/MWh. According to CECG, for this very limited benefit in cost due exclusively to the price for supply, consumers will be faced with considerably more costs due to increased risks.

CECG recognizes that wholesale suppliers bidding on full requirements products may place a certain value on the risk that they assume, for instance, for customer migration. CECG explains that the calculation for this monetization will depend on an individual wholesale supplier's perception of the level of such risk, its ability to manage the risk, and its appetite for assuming the risk. CECG claims that by removing the potential for monetization and management of this risk by suppliers, a managed portfolio approach takes the actual risk and places it on consumers. In other words, it is a zero sum game. CECG believes that this type of shifting of risks directly to consumers fundamentally alters the nature of the product being provided.

According to CECG, proponents of a managed portfolio approach often make claims that these monetizations and costs are exclusive to full requirements products. CECG asserts that this claim represents the false assumption that products such as block products in a managed portfolio approach will avoid (or else place on customers) most of the risks that are monetized in a full requirements product. CECG asserts that block products include all of the same risks – and, in turn, monetization of risks – as full requirements products for items including, but not limited to, rising fuel costs, inflation, new energy taxes, market rule changes, market price changes prior to bid acceptance, and changes in credit standing. CECG contends that it follows that the only risk that may not be priced into the costs for block products is that of load variation, including variation due to customer migration.

CECG observes that detractors of full requirements structures also often suggest that a profit is added into a bid which is otherwise avoided when purchasing other products that may be procured under a managed portfolio approach. CECG argues that any product that is purchased in the wholesale markets – e.g., whether a full requirements product, a block product, or a spot market purchase – will include in its price some level of profit that the supplier is willing and able to receive. CECG asserts that basic economic principles suggest that the price that a seller is "willing" to sell his product for will be constrained by the price he is "able" to sell his product for, so that in a competitive procurement, where only the lowest price from a pool of sellers is accepted, each seller will have an incentive to drive down the price at which he is “willing” to sell his product. CECG believes this competitively constrained price for a full requirements product will include a seller’s perceived monetizations of risk as well as a profit on the overall full requirements product. CECG suggests that depending on a supplier’s perception of the level of risks, its ability to manage risks, and its appetite for assuming risks, a supplier may have an ability to drive down further its underlying costs and overall prices. CECG claims that this especially is true for suppliers that are able to spread their costs across a large portfolio of supply obligations – if a supplier experiences lower revenue or a loss due to one of its obligations, for example, it is able to offset it against earnings across its entire portfolio of obligations. According to CECG, a utility relying on a managed portfolio approach has neither the competitive incentives to drive down its costs for managing risks nor the ability to hedge its obligations and costs across a broad, multi-regional portfolio.

CECG recognizes that a transition to a full requirements product can not occur overnight. CECG recommends that a full requirements product be used for 25% of that which is to be procured in the current procurement cycle, which will allow Illinois to achieve some of the benefits associated with a full requirements product while permitting an orderly transition under the current laddered approach.

2. IPA Position

The IPA opposes CECG's proposal at this time. The IPA states that Section 1-5 of the IPA Act provides that it is required to develop “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 . . . .” Bearing in mind its obligation under the IPA Act, the IPA questions CECG's assertion that full requirements products entail less risk for customers than block contracts.

While it is willing to discuss the use of full requirements products in future Plans, the IPA continues to believe that its current approach is preferable to full requirements contracts. At the conclusion of the 2009 procurement cycle, the IPA states that it commissioned a study on the 2009 AIC procurement against another procurement in the MISO footprint. The IPA states that AIC's procurements used three separate sealed-bid, pay-as-bid auctions to purchase standard energy products, capacity, and RECs, whereas FirstEnergy Corporation solicited full requirements service bids, which included energy, capacity, transmission, and ancillary services, among other components, in a single, consolidated product. According to the IPA, the analysis showed that under the market conditions that existed at the time of the auction bidding, the AIC procurement approach produced lower energy prices for ratepayers.

3. Commission Conclusion

Although CECG raises interesting points in support of full requirements products, the Commission is reluctant to adopt such an approach to procuring power at this time. Among the Commission's concerns is the simple fact that it is not entirely clear how

CECG's proposal would be implemented. It is particularly unclear how to translate CECG's recommendation that full requirements product be used for "25% of that which is to be procured in the current procurement cycle," into targets for the Procurement Administrator. A comparison of the load forecasts and the pre-existing contracts shown in the Plan reveals widely varying needs for additional electricity, depending on the month and time period. In this regard, CECG is not clear on what it expects the IPA to seek in full requirements RFPs. Perhaps after discussions with the IPA and other stakeholders, CECG would be able to offer a more specific proposal pertaining to a future Plan. Any future proposal, however, should also clearly address another of the Commission's concerns, which is whether a full requirements product satisfies the statutory requirement for standard wholesale products. Finally, while CECG seems to be correct that full requirements contracts eliminate risks which the IPA Plan leaves unhedged, the Commission is not convinced that eligible retail customers are in urgent need of eliminating such risk. Accordingly, the Commission will not adopt CECG's proposal in this Plan.

L. Application, Credit, and Contracting Process

CECG recognizes and appreciates the improvements that have been made in the two prior procurement cycles in standardizing products and contracts. CECG recommends that the Commission take this opportunity to make further refinements in this year's Plan. CECG states that currently, each product (energy, capacity, and renewable energy) has a separate comment process and application process, and the process is different for ComEd and for AIC. CECG believes that standardization of the procurement applications themselves would decrease the administrative burden on all parties. Ideally, CECG believes this would take the form of a single application and guarantee for all products, with bidders indicating for what products they are applying and in what service territory(ies). According to CECG, relieving the administrative burden on prospective bidders permits those entities to focus more time and resources on the bid itself, which is where consumers realize the benefits of competition. CECG believes that standardization mitigates the administrative burden on the Procurement Administrator, the Procurement Monitor, and the Commission. CECG contends that it would be less cumbersome and less expensive for bidders to use a single guarantee for all products and a single credit line to manage under a master agreement, thus potentially leading to an increase in the number of potential bidders and a decrease in the cost for the product.

CECG adds that the process could also benefit from streamlining and standardizing contracts. CECG states that previously, the three products were procured under three distinct contracts - one for energy, one for capacity, and a third for RECs. CECG adds that new agreements are entered into each year for each product, with language in the agreements inserted to try to tie them together, both across products and across years. CECG believes that entering into new contracts for each product each year is inefficient. At a minimum, CECG claims power and capacity should be procured under the same agreement, as is standard market practice, either through an EEI Agreement or ISDA Agreement with a Power Annex. CECG asserts that ideally

RECs could also be procured under the same EEI or ISDA Agreement, as well. According to CECG, the master agreement could and should be used for procurements in multiple years, updating as necessary through the annual process, rather than utilities modifying the contracts year to year unilaterally.

In response to CECG, the IPA states that it recognizes the value of standardization and is seeking to unify product requirements, such as the move towards unifying the REC procurements. The IPA indicates that it will continue to work towards this goal with the utilities, wholesalers, Procurement Administrators, and Staff.

The Commission supports efforts to standardize the procurement process as much as possible. For this reason, the Commission encourages the IPA, Procurement Administrator(s), and other stakeholders to work together toward that end. The IPA should consider using an RFP calling for a single application and guarantee for all products, with bidders indicating for what products they are applying and in what service territory(ies). Efforts to streamline and standardize contracts should also be seriously undertaken during the contract development stage of the process.

M. Regulatory Uncertainty

While CECG commends the IPA and the Commission for reducing the time period between submission of bids and contract execution, CECG contends that the time period between the submission of bids and the notification of potentially winning suppliers should be shortened, to the extent possible. CECG observes that previous IPA Plans resulted in submission of potentially winning bids in a shorter time frame than the outside limits established under the law, and the Commission likewise expeditiously evaluated and approved the results of the procurement events. CECG, however, believes further improvements can be made in shortening the time period for “informal” notification to potentially winning bidders for the AIC competitive procurements.

According to CECG, the longer that bids must remain open, and be subject to the possibility that bids will be renegotiated or rejected during a review process that does not define the criteria for such renegotiation or rejection, the greater the likelihood that consumers will ultimately be economically harmed. CECG states that while bids are held open during the review process, bidders retain the risk that market prices will change suddenly or unexpectedly. CECG insists that this risk is particularly important in procurement events involving block energy products, given the volatility in today’s market. CECG asserts that potential suppliers have to incorporate such risks in their bids to account for this time lag. CECG claims these risks will necessarily translate into higher bid prices.

CECG believes that decreasing the length of time between submission of the bid and notification of likely bid award decreases the risk that suppliers bear, which would likely lead to lower overall bid prices and would be consistent with the statute. Given that the block energy products are standard wholesale energy products, CECG claims that the review of these bids should be relatively straightforward, and should not require negotiation or additional review time. CECG appreciates the efforts by the Procurement Administrators to convey their recommendations to the Commission expeditiously, and the Commission's prompt action in reviewing those recommendations. CECG claims that any time that can be shaved off of the current process is of benefit to suppliers, and therefore ultimately will inure to the benefit of ratepayers.

CECG suggests that a potential solution to the above concern can be addressed by requiring the Procurement Administrators to notify likely winning and losing bidders (e.g., whether or not the bidder's name is being submitted to the Commission as one of the group of qualified bidders with the lowest overall prices), subject to Commission approval, as soon as possible on the same calendar day that bids are submitted. CECG reiterates its belief that the review of bids for standard block energy products should be relatively straightforward, and should not require additional time. CECG suggests that at a minimum, bidders should receive notification of the Procurement Administrator's recommendation to the Commission at substantially the same time that the recommendation is delivered to the Commission. CECG points out that this process was followed throughout the ComEd procurement processes, but was not followed in the AIC procurement processes, despite requests over the course of several years. CECG contends that this is of particular importance for the energy procurement, in which there is the greatest price volatility.

The Commission understands CECG's concerns. At a minimum, the ComEd and AIC procurement processes should be handled similarly. No party has offered any, and the Commission is not otherwise aware of any reason why the Procurement Administrator could notify bidders in the ComEd procurement whether their bids were being submitted to the Commission at substantially the same time of the submission to the Commission, but not be able to do so for bidders in the AIC procurement. The Commission directs that bidders in both the ComEd and AIC procurements be treated the same consistent with the applicable law.

N. Technical and Miscellaneous Corrections

1. Capacity Resources

The Plan provides that ComEd will continue to procure capacity from PJM under PJM's RPM program. At the end of the section on capacity resources, however, ComEd claims that the Plan contains a puzzling paragraph that states that the Procurement Administrator shall procure capacity resources for ComEd. ComEd asserts that this is inconsistent both with the rest of the capacity resource section of the Plan and with how ComEd has historically procured capacity. ComEd believes that this is an inadvertent mistake. ComEd adds that any capacity acquired by the Procurement Administrator for ComEd would be unnecessary and will simply increase customers' costs. ComEd notes that the language in this section appears to be taken verbatim from the section in the AIC portion of the Plan discussing capacity resources. ComEd understands that the Procurement Administrator procures capacity for AIC. ComEd recommends that the paragraph in question be stricken. The IPA agrees with ComEd's objection and recommends that the paragraph on page 52 beginning with “The IPA’s procurement administrator will issue solicitations . . .” be removed from the Plan. The Commission concurs that this correction should be made and directs that it be done.

2. Illinois Preference for Renewable Resources

Section 1-75(c)(3) of the IPA Act provides that “After June 1, 2011, cost-effective renewable resources located in Illinois and in states that adjoin Illinois may be counted towards compliance with the standards set forth in paragraph (1) of this subsection (c).” Given that the pending Plan involves the procurement of renewable energy resources for the period of June 2011 to May 2012, the IPA will no longer be limited to Illinois-based renewables and may look to adjacent states to acquire renewable energy resources. AIC, CECG, and Staff note, however, that the Plan appears to inadvertently limit the IPA to procuring only Illinois-based renewable energy resources for AIC even after June 1, 2011. That portion of the Plan concerning ComEd is consistent with Section 1-75(c)(3). AIC, CECG, and Staff recommend revising the Plan to make it clear that the evaluation methodology will change for the upcoming procurement cycle and will no longer include a preference for Illinois resources after June 1, 2011. The IPA recommends incorporating AIC's suggested language to accurately reflect Section 1-75. The Commission concurs that this correction should be made and directs that it be done.

3. Updated Load Forecast

ComEd notes that the Plan relies upon the data contained in the forecast that it provided to the IPA on July 13, 2010. ComEd observes, however, that the IPA attached to the Plan the forecast that ComEd provided to the IPA on July 15, 2009. In addition, ComEd claims it has been the practice in past procurement cycles for ComEd to update some information in its forecast, based on data that was not available in July, and to present the updated forecast in the procurement proceeding. ComEd continued that practice in this proceeding via its November 16, 2010 "Motion for Leave to File Updated Load Forecast." The updated load forecast is approximately 460 GWh lower because of lower load growth. ComEd recommends that the Plan be revised to incorporate the updated forecast. As with previous Plans, the IPA agrees that the Plan should be revised to incorporate ComEd’s updated forecast. The IPA states that it will modify the Plan accordingly should the Commission agree with this recommendation. The Commission agrees with this recommendation and directs that the Plan be modified accordingly.

4. Other Corrections

On page 24 of its objections, ComEd identifies several alleged technical corrections. Staff identifies what it identifies as Clerical/Typographical corrections at page 12 of its objections. On page 7 of its objections, AIC identifies what it describes as "Data Corrections."

The IPA agrees with the following corrections offered by ComEd and recommends their inclusion into the Plan:

- The 2011 demand response amount shown on page 41 as 42.0MW should be 42.9MW in accordance with the IPA filing dated July 15th.
- Table Q on page 43 should show average load in MWs rather than MWhs.
- In Attachment F to the Plan, the September 11 SF should be 1,829 not 2,615 and the Total should be 3,005 not 3,791.
- In Attachment F to the Plan, the October 11 SF should be 1,568 not 1,829.
- In Attachment F to the Plan, the column headings should refer to GWh not MW.
- In Attachment G to the Plan, the table heading for Average Load should be MWs and not MWhs.

AIC proposes to adjust Attachment D by correcting the quantity for January 2014 in the on-peak table. The IPA indicates that the correct values should be 750 MW for the 2011 IPA procurement (as opposed to 0 MW) and 650 MW for the 2012 IPA procurement (as opposed to 400 MW). The IPA recommends accepting the proposed amendments.

The IPA recommends accepting the correction that Staff identifies on page 3 of Attachment D to the Plan. Staff explains that there is a difference between the January 2013 row of Table I on page 30 of the Plan and January 2013 row of the otherwise identical Attachment D, page 3. The correct values can be found in the January 2013 row of Table I on page 30 of the Plan. AIC recommends making the same correction.

The Commission agrees that the corrections identified in this subsection should be made and directs that it be done.

VIII. FINDINGS AND ORDERING PARAGRAPHS

The Commission, having reviewed the entire record, is of the opinion and finds that:

(1) ComEd and AIC are Illinois corporations engaged in the retail sale and delivery of electricity to the public in Illinois, and each is a "public utility" as defined in Section 3-105 of the PUA and an "electric utility" as defined in Section 16-102 of the PUA;

(2) the Commission has jurisdiction over the parties hereto and the subject matter hereof;

(3) the recitals of fact and conclusions reached in the prefatory portion of this Order are supported by the record and are hereby adopted as findings of fact;

(4) the load forecast for AIC attached to the IPA's September 29, 2010 petition should be approved; the load forecast for ComEd attached to the

IPA's September 29, 2010 petition, as modified to incorporate the update in ComEd's November 16, 2010 "Motion for Leave to File Updated Load Forecast" should be approved;

(5) the load balancing procedures which the IPA proposes for ComEd and AIC, including the proposal for modifying its portfolio for ComEd and AIC in the event of a significant shift in load as laid out in its September 29, 2010 Plan (See Plan at 33 and 49-50), are reasonable and should be approved;

(6) subject to the modifications explicitly adopted in the prefatory portion of this Order, the Plan filed by the IPA pursuant to Section 16-111.5 of the PUA should be approved; as modified, the Plan, and load forecasts found appropriate above, will ensure adequate, reliable, affordable, efficient, and environmentally sustainable electric service at the lowest total cost over time, taking into account any benefits of price stability; in making this finding, the Commission is not expressing its concurrence in every statement or opinion contained in the Plan and no presumptions are created with respect thereto;

(7) to facilitate the review process and to continue movement toward uniformity between AIC and ComEd Plans, in future Plans, the IPA is encouraged to include only once discussions that are identical for AIC and ComEd; to the extent Plans differ for AIC and ComEd, the IPA should highlight those differences or distinctions.

IT IS THEREFORE ORDERED by the Illinois Commerce Commission that subject to the modifications explicitly adopted in the prefatory portion of this Order, the Plan filed by the Illinois Power Agency pursuant to Section 16-111.5 of the Public Utilities Act is hereby approved.

IT IS FURTHER ORDERED that all motions, petitions, objections, and other matters in this proceeding which remain unresolved are disposed of consistent with the conclusions herein.

IT IS FURTHER ORDERED that, subject to the provisions of Section 10-113 of the Public Utilities Act and 83 Ill. Adm. Code 200.880, this Order is final; it is not subject to the Administrative Review Law.

By order of the Commission this 21st day of December, 2010.

(SIGNED) MANUEL FLORES

Acting Chairman

ATTACHMENT C: ICC PROCUREMENT RESULTS ANNOUNCEMENTS

ILLINOIS COMMERCE COMMISSION

Public Notice of Winning Bidders and Average Prices

Concerning the Illinois Power Agency's May 2011 Procurements of Capacity Products for the Ameren Illinois Utilities

Notice Issued: May 13, 2011

Pursuant to the Illinois Power Agency ("IPA") Procurement Plan approved by the Illinois Commerce Commission ("Commission") in Docket No. 10-0563, Levitan & Associates, Inc. -- the Procurement Administrator retained by the IPA for the 2011 procurements for the Ameren Illinois Company ("AIC") -- conducted solicitations to procure capacity products on behalf of AIC for the period June 1, 2011 through May 31, 2012. Specifically, the capacity products sought are called Planning Resource Credits ("PRCs"), as defined in the Midwest Independent Transmission System Operator's Resource Adequacy Business Practice Manual.

The 2011 AIC capacity procurement has been split into two phases. Phase 1 covers AIC's capacity requirements for June 2011 and Phase 2 covers AIC's capacity requirements for July 2011 through May 2012. Bids for Phase 1 were due on April 13, 2011 and were approved by the Commission on April 15, 2011. Bids for Phase 2 were due on May 11, 2011 and were approved by the Commission on May 13, 2011. Section 16-111.5(h) of the Public Utilities Act provides that "[t]he names of the successful bidders and the load weighted average of the winning bid prices for each contract type and for each contract term shall be made available to the public at the time of Commission approval of a procurement event." 220 ILCS 5/16-111.5(h).

The names of the successful bidders for the above-described procurement events are as follows:

Winning Bidders

Ameren Energy Marketing Company
Consumers Energy Company
DTE Energy Trading, Inc.
Duke Energy Ohio, Inc.
Dynegy Power Marketing, Inc.
GenOn Energy Management, LLC
Union Electric Company d/b/a Ameren Missouri
Wisconsin Electric Power Company
Wisconsin Public Service Corporation

The weighted average of the winning bid prices in dollars per MegaWatt-Month ("$/MW-Mo") and the quantity of winning bids in MW for each contract term are shown in the following table.

Average Prices and Quantities of Winning Bids

Contract	Price ($/MW-Mo)	Quantity (MW)
June	$14.33	1,200
July	$77.01	1,170
August	$59.31	1,250
September	$5.00	1,360
October	$3.60	1,100
November	$3.08	770
December	$3.07	760
January	$3.40	950
February	$3.26	870
March	$2.77	560
April	$2.89	640
May	$4.01	750

ILLINOIS COMMERCE COMMISSION

Public Notice of Winning Bidders and Average Prices

Concerning the Illinois Power Agency's May 5, 2011 Procurement of Energy Products for the Ameren Illinois Utilities

Notice Issued: May 9, 2011

On May 5, 2011, Levitan & Associates, Inc. ("Levitan") -- the Procurement Administrator retained by the Illinois Power Agency ("IPA") for the 2011 procurements for the Ameren Illinois Company -- received bids for various energy products pursuant to the IPA's Procurement Plan approved by the Illinois Commerce Commission ("Commission") in Docket No. 10-0563. On May 9, 2011, the Commission voted to approve the bids recommended for approval by the Procurement Administrator. Section 16-111.5(h) of the Public Utilities Act provides that "[t]he names of the successful bidders and the load weighted average of the winning bid prices for each contract type and for each contract term shall be made available to the public at the time of Commission approval of a procurement event." 220 ILCS 5/16-111.5(h).

The names of the successful bidders for the above-described procurement event are as follows:

Winning Bidders

Ameren Energy Marketing Company
American Electric Power Service Corporation as Agent for Appalachian Power Company, Indiana Michigan Power Company, Kentucky Power Company and Ohio Power Company
Cargill Power Markets, LLC
Constellation Energy Commodities Group, Inc.
DTE Energy Trading, Inc.
Dynegy Power Marketing, Inc
Exelon Generation Company
J.P. Morgan Ventures Energy Corporation
Macquarie Energy LLC
Union Electric Company d/b/a Ameren Missouri

The weighted average of the winning bid prices in dollars per MegaWatt-Hour ("\$/MWH"), the number of 50 MegaWatt ("MW") winning bids, and the number of MWHs to be supplied by the winning bidders, for each contract type and for each contract term for the above-described May 5, 2011 procurement event are shown in the three tables, below.

Average Prices of Winning Bids ($/MWH)

Term	2011-12 Plan Year		2012-13 Plan Year		2013-14 Plan Year	
Type	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak
Jun	$39.68	$23.93	$41.07	$22.41	$42.44	$23.27
Jul	$44.56	$26.05	$46.55	$26.33		
Aug		$26.39	$46.72		$49.28	
Sep	$36.62	$22.26	$35.90	$22.91	$37.90	$25.01
Oct					$36.40	
Nov	$35.46		$34.79	$24.44	$36.66	
Dec	$36.60	$24.73	$36.70	$26.14	$38.24	$28.41
Jan	$39.95		$42.30		$45.69	$33.33
Feb	$41.48		$44.20			
Mar		$25.89	$39.43	$28.78	$41.59	$28.46
Apr			$40.31	$27.58		
May	$36.94		$39.67	$25.42	$40.05	
Jul/Aug	$44.54		$46.53	$25.35	$48.85	$28.34
Oct-Dec	$34.94					$26.38
Jan/Feb	$40.76	$29.64	$43.07	$31.49	$46.45	$32.78
Mar/Apr	$37.60		$39.77	$26.65		
Jun-May	$38.31	$25.87	$40.03		$42.26	$26.27

Number of 50 MW Winning Bids

Term	2011-12 Plan Year		2012-13 Plan Year		2013-14 Plan Year	
Type	On-Peak	Off-Peak	On-Peak	Product Type	On-Peak	Off-Peak
Jun	6	3	8	3	5	2
Jul	1	1	4	1		
Aug		2	5		1	
Sep	6	2	5	4	3	3
Oct					1	
Nov	1		2	1	1	
Dec	1	2	6	6	4	3
Jan	1		5		1	1
Feb	1		4			
Mar		1	3	5	2	2
Apr			2	4		
May	4		9	9	1	
Jul/Aug	5		9	8	7	5
Oct-Dec	4					1
Jan/Feb	6	2	8	5	4	4
Mar/Apr	5		6	5		
Jun-May	4	7	2		10	9

Number of MWHs to be Supplied

Term	2011-12 Plan Year		2012-13 Plan Year		2013-14 Plan Year		Total
Type	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	
Jun	105,600	55,200	134,400	57,600	80,000	40,000	472,800
Jul	16,000	21,200	67,200	20,400	0	0	124,800
Aug	0	37,600	92,000	0	17,600	0	147,200
Sep	100,800	38,400	76,000	83,200	48,000	60,000	406,400
Oct	0	0	0	0	18,400	0	18,400
Nov	16,800	0	33,600	19,200	16,000	0	85,600
Dec	16,800	40,800	96,000	127,200	67,200	61,200	409,200
Jan	16,800	0	88,000	0	17,600	19,600	142,000
Feb	16,800	0	64,000	0	0	0	80,800
Mar	0	19,600	50,400	102,000	33,600	40,800	246,400
Apr	0	0	35,200	73,600	0	0	108,800
May	70,400	0	158,400	176,400	16,800	0	422,000
Jul/Aug	172,000	0	316,800	313,600	246,400	196,000	1,244,800
Oct-Dec	201,600	0	0	0	0	59,200	260,800
Jan/Feb	201,600	76,800	268,800	186,000	134,400	148,800	1,016,400
Mar/Apr	172,000	0	206,400	194,000	0	0	572,400
Jun-May	819,200	1,640,800	408,000	0	2,032,000	2,113,200	7,013,200
Total	**1,926,400**	**1,930,400**	**2,095,200**	**1,353,200**	**2,728,000**	**2,738,800**	**12,772,000**

Notes:

Jul/Aug, Jan/Feb, and Mar/Apr are 2-month products.

Oct-Dec is a 3-month product.

Jun-May is a 12-month product.

Each “Term” consists of a 12-month period beginning June 1.

“Type” is either “on-peak” hours or “off-peak” hours.

For all products, the MISO “sink Location” and “Delivery Point Location” are both “AMIL.BGS6” (or any successor thereto); and the “Settlement Market” is “Day Ahead.”

ILLINOIS COMMERCE COMMISSION

Public Notice of Winning Bidders and Average Prices

Concerning the Illinois Power Agency's May 18, 2011 Procurement of Renewable Energy Credits for Ameren Illinois Company and Commonwealth Edison Company

Notice Issued: May 24, 2011

On May 18, 2011, NERA Economic Consulting and Levitan & Associates, Inc. -- the procurement administrators retained by the Illinois Power Agency ("IPA") for the 2011 procurements for Commonwealth Edison Company and Ameren Illinois Company, respectively -- received bids for Renewable Energy Credits ("RECs") pursuant to the IPA's Procurement Plan approved by the Illinois Commerce Commission ("Commission") in Docket No. 10-0563. On May 24, 2011, the Commission voted to approve the bids recommended for approval by the Procurement Administrators. Section 16-111.5(h) of the Public Utilities Act provides that "[t]he names of the successful bidders and the load weighted average of the winning bid prices for each contract type and for each contract term shall be made available to the public at the time of Commission approval of a procurement event." 220 ILCS 5/16-111.5(h).

The names of the successful bidders for the above-described procurement event are as follows:

Winning Bidders

EcoGrove Wind LLC
Edison Mission Marketing & Trading, Inc.
Element Markets, LLC
Exelon Generation Company, LLC
Horizon Wind Energy LLC
Iberdrola Renewables, Inc.
Invenergy Renewable LLC
MidAmerican Energy Company
Nexant, Inc.
NextEra Energy Power Marketing, LLC
Sterling Planet, Inc.
Thilmany LLC

The weighted average of the winning bid prices in dollars per MegaWatt-Hour ("$/MWH") and the number of MWHs to be supplied by the winning bidders, for each contract type for the above-described procurement event are shown in the table, below.

Average Prices and Quantities of Winning Bids

	Ameren			ComEd		
	Non-Wind	**Wind**	**All**	**Non-Wind**	**Wind**	**All**
Weighted Average Price ($/MWH)	$0.72	$0.99	$0.92	$0.65	$1.05	$0.95
MWHs of RECs	238,036	714,109	952,145	529,263	1,587,791	2,117,054

All winning bids were for RECs created with Illinois and Adjoining State resources during the period January 2011 through May 2012.

ILLINOIS COMMERCE COMMISSION

Public Notice of Winning Bidders and Average Prices

Concerning the Illinois Power Agency's May 16, 2011 Procurement of Standard Energy Products for Commonwealth Edison Company

Notice Issued: May 18, 2011

On May 16, 2011, NERA Economic Consulting ("NERA") -- the Procurement Administrator retained by the Illinois Power Agency ("IPA") for the 2011 procurements for Commonwealth Edison Company -- received bids for various energy products pursuant to the IPA's Procurement Plan approved by the Illinois Commerce Commission ("Commission") in Docket No. 10-0563. On May 18, 2011, the Commission voted to approve the bids recommended for approval by the Procurement Administrator. Section 16-111.5(h) of the Public Utilities Act provides that "[t]he names of the successful bidders and the load weighted average of the winning bid prices for each contract type and for each contract term shall be made available to the public at the time of Commission approval of a procurement event." 220 ILCS 5/16-111.5(h).

The names of the successful bidders for the above-described procurement event are as follows:

Winning Bidders

American Electric Power Service Corporation, as Agent for Appalachian Power Company, Indiana Michigan Power Company, Kentucky Power Company, and Ohio Power Company
Cargill Power Markets LLC
Constellation Energy Commodities Group, Inc.
Exelon Generation Company, LLC
Macquarie Energy LLC
MidAmerican Energy Company
Morgan Stanley Capital Group Inc.
NextEra Energy Power Marketing, LLC
Wells Fargo Commodities, LLC

The weighted average of the winning bid prices in dollars per MegaWatt-Hour ("$/MWH"), the number of 50 MegaWatt ("MW") winning bids, and the number of MWHs to be supplied by the winning bidders, for each contract type and for each contract term for the above-described procurement event are shown in the three tables, below.

Average Prices of Winning Bids ($/MWH)

Term	2011-12 Plan Year		2012-13 Plan Year		2013-14 Plan Year	
Type	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak
Jun	$45.50	$26.07	$42.51		$45.46	$26.58
Jul	$52.24	$30.23	$52.83	$28.11	$52.18	$30.90
Aug	$49.91	$30.53	$50.45			
Sep	$41.43	$23.13				
Oct						
Nov	$37.34	$22.80			$39.79	$26.40
Dec	$41.16	$26.86			$43.66	$29.38
Jan	$45.21	$33.78				
Feb	$42.90				$51.15	$39.21
Mar	$40.73	$27.43			$46.45	$32.38
Apr						
May	$39.12				$45.55	$27.55
Jul/Aug	$51.95	$30.19	$51.21	$27.72	$51.26	$29.80
Oct-Dec	$38.03				$40.61	$27.12
Jan/Feb	$44.06	$33.13			$48.81	$36.73
Mar/Apr	$39.82					$29.69
Jun-May	$43.56	$26.22			$44.54	$28.82

Number of 50 MW Winning Bids

Term	2011-12 Plan Year		2012-13 Plan Year		2013-14 Plan Year	
Type	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak
Jun	25	10	12		10	4
Jul	4	6	8	6	3	3
Aug	2	3	1			
Sep	21	10				
Oct						
Nov	9	9			2	3
Dec	11	20			8	3
Jan	6	3				
Feb	4				2	2
Mar	9	9			2	3
Apr						
May	12				1	1
Jul/Aug	19	19	22	6	16	12
Oct-Dec	11				1	1
Jan/Feb	18	18			4	5
Mar/Apr	9					1
Jun-May	6	5			26	21

Number of MWHs to be Supplied

Term	2011-12 Plan Year		2012-13 Plan Year		2013-14 Plan Year		Total
Type	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak	
Jun	440,000	184,000	201,600		160,000	80,000	1,065,600
Jul	64,000	127,200	134,400	122,400	52,800	58,800	559,600
Aug	36,800	56,400	18,400				111,600
Sep	352,800	192,000					544,800
Oct							
Nov	151,200	172,800			32,000	60,000	416,000
Dec	184,800	408,000			134,400	61,200	788,400
Jan	100,800	61,200					162,000
Feb	67,200				32,000	35,200	134,400
Mar	158,400	176,400			33,600	61,200	429,600
Apr							
May	211,200				16,800	20,400	248,400
Jul/Aug	653,600	760,000	774,400	235,200	563,200	470,400	3,456,800
Oct-Dec	554,400				51,200	59,200	664,800
Jan/Feb	604,800	691,200			134,400	186,000	1,616,400
Mar/Apr	309,600					38,800	348,400
Jun-May	1,228,800	1,172,000			5,283,200	4,930,800	12,614,800
Total	**5,118,400**	**4,001,200**	**1,128,800**	**357,600**	**6,493,600**	**6,062,000**	**23,161,600**

Notes:

Jul/Aug, Jan/Feb, and Mar/Apr are 2-month products.

Oct-Dec is a 3-month product.

Jun-May is a 12-month product.

Each “Term” consists of a 12-month period beginning June 1.

“Type” is either “on-peak” hours or “off-peak” hours.

For all products, the delivery point is the PJM “ComEd Zone.” Seller must schedule and deliver in the PJM Day-Ahead Market.

Shaded cells indicate that the product was not sought in this RFP.

News from the Illinois Commerce Commission

Voice: Springfield. 217.782.5793 Chicago. 312.814.2850 FAX 217.524.0674 BBS 217.782.9233 http://www.icc.illinois.gov

FOR IMMEDIATE RELEASE

FOR IMMEDIATE RELEASE
Dec. 15, 2010

Contact: Brian Sterling
Phone: (312) 814-6653

ICC Approves Results of Renewable Energy RFP

Today, the Illinois Commerce Commission ("Commission" or "ICC") gave the go-ahead for Commonwealth Edison Company ("ComEd") and Ameren Illinois Utilities ("Ameren") to enter into long-term contracts involving 37,234,500 megawatt-hours ("MWH") of renewable energy over 20 years (1,261,725 MWH per year for ComEd and 600,000 MWH per year for Ameren).

The Commission's action marked the culmination of two parallel Requests for Proposals ("RFPs") proposed by the Illinois Power Agency ("IPA"), as part of a procurement plan that was approved by the ICC back in December 2009. The IPA retained NERA Economic Consulting ("NERA") as the procurement administrator for ComEd and Levitan & Associates, Inc. as the procurement administrator for Ameren. The ICC retained Boston Pacific Company, Inc. as an independent monitor of both RFPs.

The contracts to be awarded to the winning bidders are for energy bundled with "Renewable Energy Certificates" ("RECs"), with both tied to the energy production of each supplier's specific renewable energy resource(s). The RFP recognized six different product categories, each corresponding to a renewable energy resource of a given type and a given location, as shown in the following table.

Product categories	**Location and Type of Eligible Renewable Energy Resource**
Illinois-Adjoining Wind	A wind resource physically located in the state of Illinois, Wisconsin, Iowa, Missouri, Kentucky, Indiana, or Michigan
Illinois-Adjoining Solar	A solar photovoltaic resource physically located in the state of Illinois, Wisconsin, Iowa, Missouri, Kentucky, Indiana, or Michigan
Illinois-Adjoining Other	A renewable energy resource as defined in the Act other than a wind or a solar photovoltaic resource and that is physically located in Illinois, Wisconsin, Iowa, Missouri, Kentucky, Indiana, or Michigan
Other-State Wind	A wind resource physically located in a state other than Illinois, Wisconsin, Iowa, Missouri, Kentucky, Indiana or Michigan
Other-State Solar	A solar photovoltaic resource physically located in a state other than Illinois, Wisconsin, Iowa, Missouri, Kentucky, Indiana or Michigan
Other-State Other	A renewable energy resource as defined in the Act other than a wind or a solar photovoltaic resource and that is physically located in a state other than Illinois, Wisconsin, Iowa, Missouri, Kentucky, Indiana or Michigan

ICC's Public Notice of Winning Bidders and Average Prices from the IPA's December 9, 2010 Procurement of Renewable Energy Resources for Commonwealth Edison Company and Ameren Illinois Company

December 15, 2010

Section 16-111.5(h) of the Public Utilities Act provides that "[t]he names of the successful bidders and the load weighted average of the winning bid prices for each contract type and for each contract term shall be made available to the public at the time of Commission approval of a procurement event." 220 ILCS 5/16-111.5(h).

<u>The names of the winning bidders are as follows:</u>

Bishop Hill Energy II, LLC
Blackstone Wind Farm, LLC (see Note 1)
FPL Energy Illinois Wind, LLC
Grand Ridge Energy IV, LLC (see Note 2)
Invenergy Illinois Solar I, LLC (see Note 2)
Meadow Lake Wind Farm, LLC (see Note 1)
Meadow Lake Wind Farm II, LLC (see Note 1)
Meadow Lake Wind Farm III, LLC (see Note 1)
Meadow Lake Wind Farm IV, LLC (see Note 1)
New Harvest Wind Project, LLC
Rockford Solar Partners, LLC
TianRun Shady Oaks, LLC

Note 1: These projects are from the same bidder with contracts executed at the project company level.

Note 2: These projects are from the same bidder with contracts executed at the project company level.

<u>The annual quantities and the average winning bid prices are as follows:</u>

	Total Quantity (MWH)	Average Price ($/MWH)
Ameren	600,000	$50.44
ComEd	1,261,725	$55.18

Each winning bid was either a wind or a solar photovoltaic resource physically located in the state of Illinois, Wisconsin, Iowa, Missouri, Kentucky, Indiana, or Michigan.

For more information about this and other electricity procurement events carried out this year, see the Commission's "2010 Procurement Process" web page, by following this link:
http://www.icc.illinois.gov/electricity/procurementprocess2010.aspx

ATTACHMENT D: IPA FINANCIAL STATEMENTS

State of Illinois
Illinois Power Agency

Combining Statement of Revenues, Expenditures and Changes in Fund Balance - Nonmajor Governmental Funds

For the Year Ended June 30, 2011 (Expressed in Thousands)
Unaudited

	Illinois Power Agency Trust 0424	Illinois Power Agency Operations 0425	Illinois Power Agency Renewable Energy Resources 0836	Total
REVENUES				
License and fees	$ -	$ 9,761	$ 7,127	$ 16,888
Interest and other investment income	45	-	-	45
Total revenues	45	9,761	7,127	16,933
EXPENDITURES				
Employment and economic development	154	3,926	-	4,080
Total expenditures	154	3,926	-	4,080
Excess (deficiency) of revenues over (under) expenditures	(109)	5,835	7,127	12,853
OTHER SOURCES (USES) OF FINANCIAL RESOURCES				
Transfers-in	-	-	-	-
Transfers-out	(24,331)	-	(6,710)	(31,041)
Net other sources (uses) of financial resources	(24,331)	-	(6,710)	(31,041)
Net change in fund balances	(24,440)	5,835	417	(18,188)
Fund balances, July 1, 2010	24,857	362	21	25,240
ESTIMATED FUND BALANCES, FEBRUARY 28, 2011	$ 417	$ 6,197	$ 438	$ 7,052

Note: These statements are unaudited. These statements are not intended to be 100% in compliance with GAAP. They are only intended to be used as a guideline for the Illinois Power Agency. Only the transactions processed through June 30, 2011 are included. Assumptions were used in the completion of these statements and, if audited, could produce a different result.

State of Illinois

Illinois Power Agency

Combining Balance Sheet
Nonmajor Governmental Funds

June 30, 2011 (Expressed in Thousands)

Unaudited

	Illinois Power Agency Trust 0424	Illinois Power Agency Operations 0425	Illinois Power Agency Renewable Energy Resources 0836	Total
ASSETS				
Cash equity in State Treasury	$ 397	$ 4,494	$ 438	$ 5,329
Securities lending collateral equity of State Treasurer	155	-	-	155
Other receivables, net	20	847	-	867
Due from other Agency funds	-	3,321	-	3,321
Total assets	$ 572	$ 8,662	$ 438	$ 9,672
LIABILITIES				
Accounts payable and accrued liabilities	$ -	$ 2,465	$ -	$ 2,465
Due to other Agency funds	-	-	-	-
Due to other State funds	-	-	-	-
Unavailable revenue	-	-	-	-
Obligations under securities lending of State Treasurer	155	-	-	155
Total liabilities	155	2,465	-	2,620
FUND BALANCES				
Unreserved, undesignated	417	6,197	438	7,052
Total fund balances	417	6,197	438	7,052
Total liabilities and fund balances	$ 572	$ 8,662	$ 438	$ 9,672
	$ -	$ -	$ -	$ -
	$ -	$ -	$ -	$ -

Note: These statements are unaudited. These statements are not intended to be 100% in compliance with GAAP. They are only intended to be used as a guideline for the Illinois Power Agency. Only the transactions processed through June 30, 2011 are included. Assumptions were used in the completion of these statements and, if audited, could produce a different result.