STATE OF ILLINOIS

ILLINOIS COMMERCE COMMISSION

Illinois Power Agency	**:**	
	:	
Petition for Approval of Initial	**:**	**08-0519**
Procurement Plan.	**:**	

ORDER

DATED: January 7, 2009

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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 5/16-111.5, requires the Illinois Power Agency ("IPA" or "Agency") to "prepare" a procurement plan ("prepared plan"), which is to be "posted" on the IPA and Illinois Commerce Commission ("Commission") websites. Section 16-111.5(d)(2) does not require that the prepared plan be "filed" with or docketed by the Commission. Similarly, comments on the prepared plan are to be submitted "to the [Illinois Power] Agency", for review by the IPA, and posted.

Nevertheless, in order to facilitate the Section 16-111.5(d)(2) process by providing a practical procedural mechanism for use by the IPA in posting the prepared plan, and by "interested entities" in submitting and posting comments on the prepared plan, the Commission docketed the IPA's prepared plan on the Commission's e-Docket system and it was assigned Docket No. 08-0519.

Pursuant to Section 16-111.5(d)(2), the IPA is required 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; the Commission's role prior to that filing is limited.

Section 16-111.5(d)(3) of the Public Utilities Act, 220 ILCS 5/16-111.5, provides, in part, "Within 5 days after the filing of the procurement plan, any person objecting to the procurement plan shall file an objection with the Commission."

Under Section 16-111.5(d)(3), "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 October 21, 2008; thus, the deadline is January 19, 2009.

Under Section 16-111.5(d)(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."

Section 16-111.5(e) specifies the major components to be included in the procurement process. Section 16-111.5(e)(4) provides that the procurement administrator shall design and issue a request for proposals ("RFPs") to supply electricity in accordance with each utility's procurement plan, as approved by the Commission. 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) provides in part:

> Within 2 business days after opening the sealed bids, the procurement administrator shall submit a confidential report to the Commission. The report shall contain the results of the bidding for each of the products along with the procurement administrator's recommendation for the acceptance and rejection of bids based on the price benchmark criteria and other factors observed in the process. The procurement monitor also shall submit a confidential report to the Commission within 2 business days after opening the sealed bids. The report shall contain the procurement monitor's assessment of bidder behavior in the process as well as an assessment of the procurement administrator's compliance with the procurement process and rules.

It further provides, "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 2 business days after receipt of the reports."

II. PROCEDURAL HISTORY

On October 21, 2008, pursuant to Section 16-111.5(d)(2) of the Public Utilities Act, the IPA, having reviewed the comments received, filed with the Commission, for approval, its procurement plan ("IPA Plan" or "Plan") with regard to securing electricity commodity and associated transmission services to meet the needs of eligible retail customers in the service areas of Commonwealth Edison Company ("ComEd"), Central Illinois Light Company d/b/a AmerenCILCO, Central Illinois Public Service Company d/b/a AmerenCIPS, and Illinois Power Company d/b/a AmerenIP, (the three Ameren utilities are sometimes jointly referred to hereinafter as the "Ameren Illinois Utilities", "AIU" or "Ameren").

Petitions for leave to intervene in this proceeding were filed by Constellation NewEnergy, Inc. and Constellation Energy Commodities Group, Inc., ("Constellation"), BlueStar Energy Services, Inc. ("BlueStar"), the Retail Energy Supplier Association

("RESA"), the PJM Power Providers Group, Inc., Wind for Illinois, and the Coalition of Energy Suppliers.

The Illinois Power Agency, ComEd, AIU, the People of the State of Illinois (the "AG" or “the People”), the City of Chicago, Midwest Generation, LLC and Edison Mission Marketing & Trading, Inc, the American Wind Energy Association, and Dynegy Inc. filed appearances in this proceeding.

Pursuant to Section 16-111.5(d)(3) of the PUA, objections to the IPA's procurement plan were filed by ComEd, AIU and the Staff of the Commission ("Staff"). On November 3, 2008 the Commission determined pursuant to Section 16-111.5(d)(3) of the PUA that no hearing in this matter was necessary in this proceeding.

Responses to the various Objections were filed by the AG, RESA, ComEd, Staff, and the IPA. Replies to Responses to Objections were filed by AIU, ComEd, and Staff.

A proposed order was issued by the Administrative Law Judge. Briefs on exceptions (“BOEs”) were filed by ComEd and the AG. Reply briefs on exceptions (“RBOEs”) were filed by ComEd and Staff.

III. OVERVIEW OF THE IPA'S PROPOSED PROCUREMENT PLAN

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 AIU. The Plan outlines a procurement strategy for the period of June 2009 through May 2014 based on detailed 5-year demand forecasts. Because existing contracts are in place for a significant portion of the load needed to meet consumers’ electricity needs over the next several years, the IPA states that procurement under its auspices will initially be limited to meeting residual consumer demand and will increase as existing contracts expire. The IPA provides a table, reproduced below, which illustrates the annual percentages of bundled service loads that are anticipated to be procured pursuant to IPA plans over a 60-month horizon. (IPA Plan at 1)

Procurement Period	ComEd	AIU
2009 - 2010	28.88%	30.42%
2010 - 2011	36.43%	52.61%
2011 - 2012	36.94%	51.44%
2012 - 2013	37.42%	70.99%
2013 - 2014	100.00%	100.00%

The IPA believes that what it describes as a "laddered approach" to procurement using a Request for Proposals bid process will provide the highest probability of obtaining the lowest long term electricity costs. 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 the IPA says there is sufficient liquidity in wholesale energy markets. The IPA asserts that procurement distributions ranging between 20% and 40% per procurement cycle were determined to be relatively comparable in their capacity to mitigate risk. According to the IPA, because future market conditions cannot be known, it 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 says modeling determined that the following three-year laddered procurement strategy would yield the lowest and most 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.

In a further effort to protect consumers, the IPA states that price risk associated with weather-related price spikes in the summer may be reduced by purchasing more than 100% of expected monthly energy requirements for peak periods in July and August. The IPA believes that hedging at 110% of expected peak energy requirements in July and August is both reasonable and advisable. The IPA suggests that greater levels of oversubscription would increase the risk that excess power would need to be sold back to the market at a loss, with the loss premium paid for by consumers. The IPA states that consistent with the Illinois Power Agency Act ("IPA Act"), final procurement purchase targets, contract executions, and timelines require Commission approval. (IPA Plan at 2)

The IPA asserts that its greatest challenge is to achieve low and stable prices when acquiring electricity in a market where prices change constantly and sometimes dramatically, particularly when the load to be served is also subject to constant flux. The IPA states that 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 and examining the 2008 procurement plans approved for ComEd and AIU, the IPA proposes a series of standard electricity products to be acquired to meet the needs of eligible customers that would be augmented by market purchases if and when necessary. (Id.)

The IPA points out that Section 16-113 of 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 ("C&I") customer classes with demand greater than 100 kilowatts ("kW") are deemed competitive, as are AIU customers with demand of at least 400 kW. According to the IPA, the statue allows ComEd customers with demand below 400 kW, and AIU customers with demand below 1 megawatt ("MW"), to continue to purchase power and energy from the utility through May 30, 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 AIU will procure power for a customer in a class deemed competitive only by purchasing electricity in the hourly spot market and passing through the market prices. (IPA Plan at 6)

The IPA says its procurement plans will be designed to accommodate the electricity needs of all customers who are still buying bundled service electricity from ComEd and AIU. The IPA states that for the month of June 2008, 47% of the total electricity usage of ComEd customers and 45% of AIU customers' total usage was supplied through fixed price bundled utility service. This is the load that will be served through IPA procurement planning. The IPA states that according to reports filed by ComEd and AIU with the Commission, as of June 30, 2008, 68% of ComEd's commercial and industrial customers with demand above 100 kilowatts ("kW") and 91% of the total load of those customers had switched to alternative suppliers or hourly pricing. The IPA adds that of ComEd's C&I customers with demand below 100 kW, 11% had switched, with 25% of that load. According to the IPA, approximately 7% of AIU's C&I customers with demand below 1 MW and 38% of that load were no longer receiving bundled utility service. The IPA says that neither ComEd nor AIU reports any significant switching to alternative suppliers by residential customers. (Id.)

The IPA indicates that it must submit a Plan each year identifying projected loads for "eligible retail customers," and a plan for fulfilling those load requirements. 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.

IV. LOAD FORECASTS

The IPA states that pursuant to Section 16-111.5(d)(1) of the PUA, on July 15, 2008, ComEd and AIU prepared and submitted to the IPA separate five-year hourly load projections. The IPA adds that it requested, and ComEd and AIU 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 AIU. Copies of ComEd's and AIU's load forecast submittals are included in Attachment A and C to the IPA's Plan. (IPA Plan at 10)

The IPA says it relied on load forecasts from the ComEd and AIU 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 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 AIU's data projections are updated annually, the IPA indicates it will readjust load projections should retail switching exceed ComEd and AIU's projections. The IPA says this readjustment will be based on the impact of retail switching among eligible retail customers based on Commission generated reports.

According to the IPA, the ultimate goal of the forecasts is not to identify the combined load of all customers of ComEd and AIU; rather, it is to identify the load requirements of the “eligible retail customers” for ComEd and AIU, individually.

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 at least 400 kW are no longer eligible for bundled service, and those from 100-400 kW may remain on bundled service until May 31, 2010. The IPA says ComEd's load forecasts are adjusted accordingly. (IPA Plan at 13)

The IPA indicates that ComEd utilizes a forecasting process based on econometric models that produce monthly sales forecasts for primary customer classes including: Residential, Small C&I and Large C&I. The IPA states that 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 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 procurement plan for the ComEd portfolio. (Id.)

As previously discussed, Section 12-103(c) of the PUA also establishes specific requirements for utility company Demand Response Programs. In its original plan, the IPA interpreted this provision to require that the peak will shrink by 0.1% each year, eventually becoming 1.0% lower than it would otherwise be absent the demand-response measures. ComEd described this requirement differently, stating that it is called upon to implement demand response measures that reduce peak demand by 0.1% over the prior year, and that this requirement continues for 10 years. For the purpose of projecting loads for ComEd this year, the IPA’s revised plan assumes that ComEd's demand response programs are sufficient to achieve its targeted peak reductions, and therefore incorporates ComEd's method of calculating the effect of demand response programs. (IPA Plan at 13-14; ComEd BOE at 1-2)

Based on ComEd’s analysis, the IPA says the effective reduction in ComEd’s maximum system load requirements for eligible retail customers due to demand response programs is projected to be: 11.7 MW in 2009, 11.3 MW in 2010, 11.4 MW in 2011, 11.6 MW in 2012, and 11.8 MW in 2013. As stated previously, Section 12-103(b) of the PUA also establishes specific requirements for energy efficiency programs that reduce energy consumption of delivery services customers by 0.2% in 2008 planning year and by an additional 0.2% each year through 2012, growing to a total decrease in energy consumption of 1.8% in 2013. The IPA indicates that the annual incremental reductions in ComEd’s supply requirements to be acquired through the RFP process (net of customer switching) is projected to be: 127 gigawatt-hours ("GWh") in 2009, 195 GWh in 2010, 264 GWh in 2011, 340 GWh in 2012, and 386 GWh in 2013. (IPA Plan at 14)

B. Ameren Illinois Utilities' Load Forecast

The IPA states that AIU's five-year hourly load forecast identifies load projections for eligible retail customers. As noted above, eligible retail customers include residential and other customers who are entitled to purchase electricity from AIU under fixed-price bundled service tariffs.

AIU, 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 from 1995 to 2006 for weather, seasonal variables and economic conditions, a detailed core consumption model was developed. According to the IPA, AIU's statistical models are measured for accuracy against past period consumption volumes for each customer class. 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. (IPA Plan at 11-12)

Forecasted portfolio volumes, the IPA adds, are generated by altering model variables within expected ranges and examining model outputs. The IPA indicates that the resulting High, Expected, and Low volume scenarios are generated. The IPA selected the Expected load model as the basis of the procurement Plan for the AIU portfolio. The IPA states that because the PUA declares retail customers with peak demand of 1000 kW and above to be competitive as of May 2008, the Plan does not include those volumes.

As previously noted, the PUA also declares electricity supply to all AIU customers with demand above 400 kW to be competitive. As a result, customers above 400 kW taking service from an alternative retail electric supplier ("ARES") as of the effective date of PUA, or who subsequently switch to an ARES, are no longer eligible to take bundled service under tariffs offered by AIU. Further, those customers above 400 kW who continue to receive bundled utility service will be placed on the AIU tariff Rider HSS (Hourly Supply Service) if they do not choose to take service from an ARES by June 1, 2010. The IPA indicates that load projections for the 400-1000 kW customer classes are adjusted to reflect estimated migration to ARES providers. The IPA states that this Plan includes procurement necessary to meet the supply needs of customers with demand of 400-1000 kW that are projected to remain on AIU bundled service. (IPA Plan at 12)

Section 12-103(c) of the PUA also establishes specific requirements for utility company Demand Response Programs as follows:

> 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. This requirement commences June 1, 2008 and continues for 10 years.

According to the IPA, because the requirement appears to be cumulative, the peak to be served will shrink by 0.1% each year, eventually becoming 1.0% lower than it would otherwise be absent the demand-response measures. The IPA states that there is a difference of opinion as to the appropriate interpretation of the statute, with ComEd asserting that the requirement is not cumulative. The IPA indicates that AIU calculates this requirement as cumulative, and suggests that other parties may have differing views. The IPA claims it has a stake in the interpretation of the language only insofar as it affects the projected peak load of eligible customers to be served. 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, and therefore incorporates each utility's method of calculating the effect of demand response programs. The IPA suggests it will modify the calculation of peak loads as the legal standard for demand response is clarified. (IPA Plan at 12)

Based on AIU's analysis, the IPA says the effective reduction in AIU's maximum system load requirements for eligible retail customers due to demand response programs is projected to be: 7 MW in 2009, 14 MW in 2010, 18 MW in 2011, 23 MW in 2012, and 27 MW in 2013.

The IPA also indicates that Section 12-103(b) of the PUA establishes specific requirements for Energy Efficiency Programs that reduce energy consumption of delivery services customers by 0.2% in 2008 planning year and increasing 0.2% each year through 2012, and then increases to 1.8% in planning year 2013. The IPA says that the annual incremental reductions in AIU's supply requirements to be acquired through the RFP process (net of customer switching) is projected to be: 78.1 GWh in 2009, 100.5 GWh in 2010, 130.4 GWh in 2011, 159.3 GWh in 2012, and 217.8 GWh in 2013. (IPA Plan at 12-13)

V. PORTFOLIO DESIGN

The IPA is responsible for developing and implementing a plan to secure electricity supplies for eligible retail customers for ComEd and AIU. Citing Section 16.111(d)(4) of the PUA, 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 it must arrange purchases of electricity from the wholesale market in a manner that accommodates both changing prices and load requirements. The IPA claims that designing the portfolio requires an understanding of the variables that drive price and load fluctuation, and the extent to which those variables can affect price. The IPA says one such factor is risk. For the purposes of the IPA's analysis and planning, risk is defined as any market condition or internal and external processes that have the potential of raising prices or increasing their volatility. (IPA Plan at 17)

A. Risk Assessment

According to the IPA, the PUA, in Section 16-111.5, 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 says the average upward movement of electricity prices is due to rising costs for multiple elements in the electricity sector: fuel costs, capacity costs, transmission costs, and the cost of plant additions and construction all put upward pressure on future prices for electricity. The IPA states that the ability to enter the market with some flexibility as to timing enhances the dollar-cost averaging approach to procurement and can slow the long-term upward price trend.

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. In the IPA's view, short-term risks can be mitigated by arranging procurement events as close to the expected load volumes as possible. Additionally, the IPA recommends some oversubscription of electricity for the peak periods of July and August. The IPA asserts that historically, July and August have the highest potential to generate instances of forced buying in high spot markets. (IPA Plan at 18)

According to the IPA, 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 over time. The IPA states that consumption by bundled service customers is relative inelastic, meaning that usage of electricity does not diminish significantly when prices are high, in part because customers are not directly exposed to these prices. The IPA says 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 IPA says the cost of their consumption during high cost periods is averaged across the entire portfolio. The IPA believes it does not presently have tools with which to address this issue. The IPA suggests this could be addressed, in part, by changing utility rate structures so that individual ratepayers are exposed to the real costs of consumption during peak cost periods, or conversely, are rewarded for reducing demand during system peaks. The IPA further suggests that implementation of demand response programs and the advent of “Smart Grid” systems may provide effective tools to address the need to reshape loads. (IPA Plan at 18)

The IPA also asserts that unpredicted migration to ARES presents some level of risk to the Portfolio insofar as migration can cause cost spiraling under certain conditions. The IPA posits a scenario where a high percentage of anticipated long-term load requirements for the IPA portfolio were secured with fixed volume contracts and market prices decreased in the future. In such a situation, the IPA claims higher-than-market bundled rates would motivate switching by those customers who could be profitably served by ARES at the relatively lower market prices. The IPA states that 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. The IPA claims that over time, bundled-rate customers could see high rate volatility, as well as, potential inverse market price signals (bundled rates would be rising while market prices were falling). For this reason, the IPA believes that laddering-in purchases over time enables the IPA to minimize risk for consumers by allowing the IPA to adjust procurement volumes in response to changing customer needs and market conditions.

According to the IPA, contract terms present risk to the portfolio to the extent that the underlying credit requirements for the bidders and the utility may increase costs that are ultimately borne by the end-use customer. The IPA says contracts entered into as a result of the procurement process will be through either an International Swaps and Derivatives Association (“ISDA”) agreement for financial instruments such as fixed/floating rate swaps or an Edison Electric Institute (“EEI”) agreement for physical products such as capacity. Individual transactions will be memorialized utilizing standard transaction specification sheets, such that, to the extent practicable, purchasing decisions will be made on the basis of price, rather than non-price factors. (Id.)

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 asserts that particular risks in this area are the annual planning cycle, time between procurement events, and time between bid and contract execution. According to the IPA, this present schedule yields a procurement event that occurs as many as nine months after load projections are made and eight months after the initial Plan is developed. The IPA states that changes in loads 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 risk. The IPA indicates that it intends to engage the Commission, AIU and ComEd, as well as other stakeholders in an effort to reduce the lead time in the process for future procurement cycles, consistent with statutory requirements. (IPA Plan at 18-19)

The Plan filed states that a single annual procurement event increases portfolio risk by exposing all transactions to only one set of market conditions, and increases risk to the Portfolio because price risk is minimized by more frequent and smaller volume entries into the market. Additionally, the Plan states that a single annual procurements increase the potential for bidders to exercise some level of market power depending on market conditions. The IPA indicates potential ways to mitigate these risks will be addressed in future procurement plans, including assessment of the costs and benefits of different options for conducting multiple procurement events during a year.

The IPA indicates that the PUA allows a period of four days for review of the bids submitted during the procurement event (two days for the Procurement Administrators and Procurement Monitors to submit reports, and two days for the Commission to review and consider the reports). The IPA says the time lag between the submission of wholesale electricity bids and their acceptance creates risk for bidders, which translates into higher costs for consumers. In order to lay off the potential liability in the event that market prices rise between the time a bidder submits a bid and the contract is executed, the IPA says bidders may purchase five-day option contracts to guarantee the price they submit to the IPA. According to the IPA, the insurance has a premium, and that premium is embedded in the bid price of the electricity. (IPA Plan at 19)

The IPA states that a five-day option premium is estimated to cost between $1.40 and $1.60/megawatt-hour ("MWh"). If underlying volatility increases in the market (e.g. loss of baseload generating units), or if market prices increase generally (e.g. carbon tax costs are levied), then the IPA claims premium costs will increase. As the volumes of electricity purchased through the IPA process increase over time due to the expiration of legacy supply contracts, the IPA asserts that the total cost premiums built into wholesale bids increase. Over the next three procurement cycles, the IPA estimates the total cost of the embedded premiums to exceed $150 million.

To mitigate this risk, the IPA recommends that review processes be abbreviated and automated to an extent that allows for approval of bids to occur on the same day they are submitted. The IPA recommends that the Commission, its procurement monitor, and the procurement administrator work together to devise a timely process to address this risk while maintaining appropriate oversight functions, and detail any revisions in the process to bidders in the relevant RFPs. (Id.)

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 the PJM Interconnection ("PJM") or Midwest Independent Transmission System Operator ("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. According to the IPA, mitigation options outside of the proposed Portfolio Design would have limited utility as the Portfolio Design is geared towards mitigating general electricity price risk. However, the IPA suggests that renewable energy resources that have zero fuel costs, such as wind power, can be cost-effective hedges against rising fuel costs for conventional resources. (IPA Plan at 20)

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, the IPA says 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.

According to the IPA, mitigating weather risk is accomplished through portfolio design which accounts for correlated market price – portfolio load movements, and its recommendation for purchasing approximately 10% more volume for the peak period contracts in the July and August periods for ComEd and AIU. In the IPA's view, oversubscription is appropriate during those times of the year when weather–driven increases in demand occur (during daytime hours in the months of July and August); however, the IPA says there is no guarantee that oversubscription will yield savings. (IPA Plan at 21)

The IPA suggests that over time, improvements to metering and information infrastructures may allow for greater accuracy in projecting load correlations with weather. Access to such data, the IPA says, would allow for better long range forecasting, as well as introduce the ability for short term purchases (e.g. weekly strip volumes) based on short range weather variance.

The IPA observes that AIU operates in the 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 up to $3 billion in transmission investments in the MISO region, and as much as $1.7 billion in similar investments in the PJM region. The IPA avers that costs due to transmission risks are already being borne by MISO and PJM participants insofar as congestion charges at various points in those systems are high as a result of transmission congestion. As investments are made in transmission systems, the IPA suggests that in theory, congestion charges will decline; however, the IPA says the costs of building transmission will be recovered from customers.

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, 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%. The IPA says some of these costs may be offset by contributions of wind assets towards system reliability and other ancillary services. The IPA believes it is limited in its ability to mitigate these risks outside of factoring them into cost modeling over the longer range horizon and seeking offsetting cost avoidance elsewhere within the Portfolio.

The IPA states that market conditions generally relate to the drivers of market prices, customer usage, and customer switching levels. The IPA claims these variables are included in the statistical modeling conducted by the IPA relative to the Portfolio Design.

The IPA believes its analysis provides a reasonable representation of the significant risks associated with the June 2009 – May 2010 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 recommend an alternative to its recommended portfolio. (IPA Plan at 21)

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. (IPA Plan at 22)

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 says locational marginal prices ("LMP") provided through regional transmission organizations ("RTO") are the bases 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 Procurement 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 says the risk profile of its proposed portfolio changes over time. Accordingly, the IPA indicates it will be making process improvements that allow for continuous monitoring and annual adjustments to the portfolio strategy as each Plan is developed. (Id.)

Next, the IPA discusses the premises upon which the IPA 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. (IPA Plan at 23)

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 AIU, the IPA indicates that 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. 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 of the average (A) Year-over-Year Price Variance, (B) Mark-to-Market Price Variance, and (C) Longitudinal Variance. (Id.)

According to the IPA, a set of potential portfolios was evaluated with model runs of 5,000 iterations against the risk metric defined above. There are three main sections to the model, the first of which is the price section. In the price section, the IPA indicates that the model uses monthly forward peak and off-peak New York Mercantile Exchange ("NYMEX") pricing through 2012 as of August 15, 2008. 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 2012, the IPA says 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 says forward price curves are assumed to vary over time. According to the IPA, 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. The IPA asserts that analyses of the historical movements in prices of the front end of the forward energy curve reveal annualized volatilities of 26% and 17% for peak and wrap contracts, respectively. The IPA claims these volatilities include changes in prices due to all factors, including fuel price movements. The IPA says market prices volatility was selected as the appropriate representative of market price risk as ComEd and AIU do not own generation and therefore cannot control significant variables such as fuel expense. (Id.)

The IPA says 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. According to the IPA, 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 IPA says 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 IPA says 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 indicates that monthly spot prices are then developed based on the historical volatility observed between the price of the forward at the beginning of the month and the realized average spot price observed for each month. (IPA Plan at 24)

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 Plan indicates that the model starts with the base load estimates for eligible retail customers supplied by ComEd and AIU on July 15, 2008 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 AIU.

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 and (2) the amount hedged through the swap arrangements. In addition, the IPA says the model does allow for the adjustment of the amount purchased for summer (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. (Id.)

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 cost for energy supplied via the auction process (price fixed but quantity varies), 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. (Id.)

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). Based on an analysis of historical monthly spot prices and loads, average monthly gross-up factors were estimated for both the peak and the wrap periods. For the peak period, the IPA says gross-up factors were approximately 10% in summer and 3% in other months. For the wrap period, the IPA says gross up factors were approximately 14% in summer and 6% in other months. The IPA states that the same historical analysis also shows these gross-up factors are highly variable over time. (IPA Plan at 25)

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. (Id.)

C. Proposed Portfolio Design

The IPA claims 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. 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 says 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. (IPA Plan at 25)

For the portfolio structure analysis, the IPA indicates it focused on the 2014-2015 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 says that procurement distributions ranging between 20% and 40% per procurement cycle were determined to be relatively comparable in their capacity to mitigate risk. Because it believes 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. The IPA describes this acquisition structure as a laddered procurement strategy. (IPA Plan at 26)

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. To see how this strategy might impact the average energy cost of the portfolio, the IPA performed a stress test with a High case where prices increase 10%/yr, a Low case where prices decrease by 10%/yr; and a swing price case where prices oscillate: up 50%, down 50%, up 100%, down 50%, up 100%. The IPA says that the stress variables used in the testing are annual rate changes. According to the IPA, such annual changes are statistically more significant than the shorter duration, though more dramatic, cost escalations experienced in energy markets over recent months. The IPA contends that while the target portfolio provides dampening in sustained high or low cases, the impact is relatively modest. According to the IPA, a major benefit of the proposed laddered procurement approach is seen in the swing case where year-to-year price changes are greatly mitigated in a volatile market. (Id.)

The IPA states that in the procurement plan submitted for the 2008-2009 period, questions were raised regarding whether the risk associated with weather-driven price spikes in the summer would be reduced by purchasing more than 100% (oversubscribing) of expected monthly requirements for peak periods in July and August. To analyze this issue, the IPA says it first determined 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). The IPA assessed three change cases where it purchased 110%, 120% and 130% of July and August non-Auction Supplier Forward Contracts ("ASFC") peak loads. The IPA says no correlation was assumed between spot prices and gross-up factors consistent with historical monthly data. (IPA Plan at 27)

According to the IPA, the results of its analysis indicate that purchasing at 110% of expected peak requirements in July and August is not unreasonable. The IPA says however, that the greater the level of oversubscription, the greater the risk that excess power may be sold back to the market at a loss, with the loss premium paid for by consumers. The IPA states that the 110% July/August hedge ratio is approximately equal to one plus the average gross-up factor. The IPA believes this is consistent with the intuitive observation that if the around-the-clock energy price were to go up (or down) by $1/MWH, the average cost would rise (or fall) by $1 x (1+gross-up factor). (IPA Plan at 28)

The IPA contends that its 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. The IPA suggests this 30/35/35 model portfolio is analogous to dollar cost averaging in investing. The IPA says this laddering of energy supply contracts does not apply to the purchase of renewable energy credits.

Given the high-level nature of its analysis, the IPA states that the 30/35/35 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 (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 AIU 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. The IPA also notes that its recommendation for hedging peak period loads in July and August at 110% of ComEd's and AIU's expected exposure is consistent with the Commission's orders regarding procurement for the 2008/2009 procurement plans for AIU and ComEd. (IPA Plan at 28, citing, Docket Nos. 07-0527 and 07-0528)

VI. APPLICATION OF PROPOSED PORTFOLIO DESIGN

The IPA explains how the power and energy will be procured for delivery from June 1, 2009, through May 31, 2012, for ComEd's and AIU's eligible retail customers, as these customers are defined by the PUA, as well as for ComEd's and AIU's customers whose service has been declared competitive but who retain the right to remain on fixed-price bundled tariff service during the June 2009 – May 2010 delivery period. This larger group of customers is referred to by the IPA as the "Included Retail Customers".

The IPA states that generally, the portfolio includes residential, commercial and industrial customers that have a peak demand less than 100 kW, and a subset of commercial and industrial customers that have a peak demand between 100 and 400 kW. For ComEd specifically, this includes customers from the following supply groups as defined in ComEd's currently effective General Terms and Conditions:

- Residential Customer Group: the customer supply group applicable to any retail customer in the residential sector and using electric service for residential purposes.
- Watt-Hour Customer Group: the customer supply group applicable to any retail customer in the nonresidential sector, using electric service for nonresidential purposes, and for which no metering equipment or only watt-hour metering equipment is installed at the retail customer's premises. Generally, a retail customer in this customer supply group uses less than 2,000 kilowatt-hours ("kWh") during a monthly billing period.
- Demand Customer Group: Beginning with 2008 monthly billing period, Demand Customer Group means the customer supply group applicable to any retail customer in the nonresidential sector, using electric serves for nonresidential purposes, and for which (a) the Self-Generating Customer Group is not applicable, (b) the Competitively Declared Customer Group is not applicable, and (c) demand metering is installed at the retail customer's premises.
- Dusk to Dawn Lighting Customer Group: the customer supply group applicable to (a) any retail customer in the lighting sector and using electric service for a street lighting system that operates on a dusk to dawn basis, or (b) the portion of electric service provided to a retail customer in the residential sector or nonresidential sector, located outside the City of Chicago, and using such portion for private, outdoor, fixture-included, dusk to dawn lighting purposes, provided that the Competitively Declared Customer Group is not applicable to the retail customer described in item (a) or (b).
- General Lighting Customer Group: the customer supply group applicable to any retail customer (a) in the lighting sector, (b) using electric service for a lighting system other than a lighting system that operates on a dusk to dawn basis, and (c) to which the Competitively Declared Customer Group is not applicable.

(IPA Plan at 43-44)

For AIU specifically, this includes customers from the following supply groups as defined in AIU's currently effective General Terms and Conditions:

- Residential (DS-1)
- Non Residential less than 150 kW (DS-2)
- Non Residential from 150 kW up to 400 kW (DS-3A)
- Non Residential from 400 kW up to 1,000 kW (DS-3B)
- Lighting Service (DS-5)
  (IPA Plan at 28)

A. Supply Requirements

The IPA provides two tables, reproduced below, which includes the forecasted monthly supply requirements of ComEd and AIU for the period June 1, 2009 through May 31, 2010. The IPA says this forecast includes anticipated normal weather, the effect of competitive declarations, energy efficiency and demand response programs, and the impact of the impact of forecasted customer switching.

ComEd Supply Requirements

Contract Month	Total Load (MWh)		Average Load (MW)	
	On-Peak	Off-Peak	On-Peak	Off-Peak
June 2009	2,141,623	1,873,337	6,084	5,091
July 2009	2,734,169	2,309,153	7,430	6,141
August 2009	2,346,163	2,382,159	6,983	5,839
September 2009	1,881,759	1,785,096	5,600	4,649
October 2009	1,721,639	1,621,614	4,891	4,137
November 2009	1,711,303	1,840,111	5,348	4,600
December 2009	2,167,273	2,098,047	6,157	5,352
January 2010	1,990,348	2,307,359	6,220	5,442
February 2010	1,868,295	1,795,009	5,838	5,099
March 2010	1,902,638	1,681,239	5,170	4,471
April 2010	1,606,834	1,453,921	4,565	3,951
May 2010	1,540,370	1,755,747	4,814	4,141

(IPA Plan at 44)

AIU Supply Requirements

Contract Month	Total Load (MWh)		Average Load (MW)	
	On-Peak	Off-Peak	On-Peak	Off-Peak
June 2009	942,541	736,669	2,678	2,002
July 2009	1,136,326	912,390	3,088	2,427
August 2009	1,017,170	973,053	3,027	2,385
September 2009	841,219	801,700	2,504	2,088
October 2009	786,641	686,384	2,235	1,751
November 2009	697,060	775,454	2,178	1,939
December 2009	882,347	843,368	2,507	2,151
January 2010	831,083	979,422	2,597	2,310
February 2010	780,211	768,880	2,438	2,184
March 2010	796,283	707,067	2,164	1,880
April 2010	685,986	604,054	1,949	1,641
May 2010	622,178	691,911	1,944	1,632

(IPA Plan at 28-29)

According to the IPA, ComEd will procure the capacity and ancillary services required by the “Included Retail Customers” from several sources. First, ComEd's existing ASFCs supply approximately one-third of these customers’ capacity and ancillary services’ requirements. Second, ComEd will procure the remaining capacity and ancillary services required by these customers directly from PJM-administered markets. The IPA states that 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 RPM capacity prices for the June 2009 - May 2010 period have already been determined through a competitive bid process, so the IPA views direct procurement from PJM results as a reasonable approach to procuring capacity for these customers. Furthermore, the IPA indicates 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. (IPA Plan at 45)

The IPA reports that capacity is also required of AIU to ensure reliable service to its customers and is mandated by the MISO and the AIU National Electric Reliability Corporation ("NERC") Region, the Southeastern Electric Reliability Council (“SERC”). The IPA says the MISO Open Access Transmission and Energy Markets Tariff (“MISO Tariff”) requires that AIU demonstrate it has acquired capacity in an amount equal to its expected peak load plus planning reserves. As discussed more fully below, the IPA states that MISO further specifies that the amount of planning reserves must be a minimum of 14.3%. The IPA indicates that the requirement for planning reserves may be different for subsequent planning years depending on the results of an annual technical analysis to be performed by MISO (the next analysis will be completed in the winter of 2008/2009). The 2008 planning reserve value of 14.3% was used in forecasting the capacity requirements for the entire five year planning period; however, since the future value of planning reserves is unknown at this time and may change based on the outcome of MISO technical analysis, the IPA claims the exact quantities of capacity required may vary somewhat from what is included in the Plan. (IPA Plan at 29)

For AIU, the IPA states that the Plan forecast for peak demand was developed in similar fashion as the energy forecast and included adjustments for competitive declarations, customer switching, demand response, and existing auction contracts. The IPA adds that the procurement plan forecast for peak demand was developed in similar fashion as the energy forecast and included adjustments for Existing Auction and Swap Contracts, competitive declarations, customer switching, and demand response. For each month of the period June 2009 through May 2010, the IPA says an hourly peak forecast was developed after adjustment for the above factors. (IPA Plan at 29)

The load forecast presented in the tables above is a forecast of the expected full energy requirements of the Included Retail Customers. The IPA notes however, that ComEd and AIU will not need to procure that amount of energy in order to serve that load due to pre-existing contracts for supply. The IPA observes that pursuant to the Commission Order in Docket No. 05-0159, ComEd and AIU entered into a number of ASFCs with the winners in the 2006 Illinois Auction to supply power, energy and ancillary services to serve the full electrical requirements of the residential and smaller than 400 kW C&I customers. The IPA says one-third of the ASFCs expired on May 31, 2008, another one third will expire on May 31, 2009, and the remaining third will expire on May 31, 2010. (IPA Plan at 29-30 and 45)

In addition, pursuant to section 16-111.5(k) of the PUA, the IPA indicates that ComEd entered into a five-year swap contract with Exelon Generation ("ExGen"). The IPA says this agreement will provide price certainty for 2,000 MW of Around-The-Clock (“ATC”) energy that ComEd will procure through the PJM spot markets for the period June 1, 2009 through May 31, 2010, and 3,000 MW of ATC energy that ComEd will procure through the PJM spot markets for the period June 1, 2010 through May 31, 2013. (IPA Plan at 45)

Similarly, the IPA indicates AIU entered into a five-year swap contract with Ameren Energy Marketing. AIU's contract will provide price certainty for 800 MW of ATC energy that AIU will procure through the MISO spot markets for the period June 1, 2009 through May 31, 2010, and 1,000 MW of ATC energy that AIU will procure through the MISO spot markets for the period June 1, 2010 through December 31, 2012. (IPA Plan at 30)

The IPA provides tables, reproduced in part below, which identify the Monthly Residual Load volumes for the ComEd and AIU over the Procurement Period. The IPA indicates that the Monthly Residual Load Volumes are derived by subtracting pre-existing contract volumes from projected load volumes.

ComEd Residual Supply Requirements

Contract Month	Residual Volumes (MWh) On-Peak	Residual Volumes (MWh) Off-Peak
June 2009	721,181	510,645
July 2009	992,034	784,667
August 2009	810,809	769,250
September 2009	580,250	419,924
October 2009	441,695	295,132
November 2009	498,817	424,534
December 2009	738,250	612,182
January 2010	684,512	687,473
February 2010	603,290	490,520
March 2010	530,144	366,810
April 2010	365,296	231,537
May 2010	385,066	320,393

(IPA Plan at 46)

AIU Residual Supply Requirements

Contract Month	Residual Volumes (MW) On-Peak	Residual Volumes (MW) Off-Peak
June 2009	977	528
July 2009	1,249	810
August 2009	1,209	783
September 2009	861	585
October 2009	683	362
November 2009	645	486
December 2009	863	628
January 2010	923	733
February 2010	818	649
March 2010	636	448
April 2010	493	289
May 2010	490	283

(IPA Plan at 30)

B. Energy

In order to meet the requirements of the Included Retail Customers, the IPA indicates that certain wholesale supply products must be procured. These include energy, capacity, and ancillary services. The IPA says the determination of the appropriate portfolio (i.e., form, term-lengths, and mix) of these products is guided by the specific goals for this Procurement Plan as defined in Section 16-111.5(j)(ii) of the PUA:

> The Commission shall approve 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.

(IPA Plan at 47)

Under the IPA's Plan, energy required by **ComEd's** Included Retail Customers comes from four sources. First, the ASFCs cover approximately one-third of these customers' energy requirements. Second, the swap contract with ExGen provides a financial hedge on 2,000 MW of ATC energy during the June 2009 – May 2010 period, and 3,000 MW of ATC energy during the June 2010 – May 2013 period. Third, IPA will solicit standard wholesale products through a sealed-bid RFP per its proposed Plan. Finally, balancing energy will be procured from the PJM-administered day-ahead and real-time energy markets. (IPA Plan at 47)

The IPA states that energy required by **AIU's** Eligible Retail Customers comes from three sources. First, the ASFCs cover approximately one-third of these customers' energy requirements. Second, the swap contract with Ameren Energy Marketing provides a financial hedge on 800 MW of ATC energy during the June 2009 – May 2010 period, and 1,000 MW of ATC energy during the June 2010 – December 2011 period. Third, under the IPA's Plan, AIU will utilize the physical energy necessary to meet its combined load requirements via the MISO day-ahead and real-time energy markets, and will enter into financial swap contracts to hedge price exposure for Residual Volumes. The IPA indicates it will solicit standard wholesale products through a sealed-bid RFP under its proposed Plan. (IPA Plan at 32)

According to the IPA, a financial swap is a commercial transaction between two parties involving the exchange (swap) of risk. The IPA states that in this instance, AIU desires to pay a fixed price, and will settle all loads with the MISO at LMP. Under a swap transaction, the IPA says AIU will pay a fixed price to its supplier in exchange for receiving a floating price (MISO LMPs) from the supplier. As such, the LMP paid by AIU to the MISO is offset by the LMP received from the supplier, leaving AIU only paying the fixed price. In the IPA's view, financial swaps provide the same level of hedging as physical transactions. According to the IPA, the use of financial swaps will not adversely affect reliability as AIU will contract for sufficient capacity to meet the load obligations, and as such the contracts for such capacity shall obligate the seller to offer such capacity into the MISO markets. (Id.)

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 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. 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 cannot approximate customer load shapes on a more granular basis than a monthly on-peak/off-peak basis. (IPA Plan at 32, 47-48)

Given these facts, the IPA plans to issue solicitations for monthly on-peak and off-peak standard wholesale block energy products (or their equivalent volumes in seasonal or varietal strips) for delivery during the June 2009-May 2012 period. The IPA says the target procurement quantities are determined by multiplying ComEd's and AIU's average net load obligation (average forecasted load less ASFC supplied megawatts) 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). The IPA emphasizes that net load requirements for July and August are then multiplied by 1.1 to help mitigate potential spikes in summer prices and loads.

Next, megawatts covered by the ExGen and Ameren Energy Marketing swaps are subtracted from the target requirements. To the extent the calculated procurement quantity for a period is less that 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. (IPA Plan at 32, 48)

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, the utilities, the procurement monitor and the Commission Staff. 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. (Id.)

According to the IPA, the PUA provides that it is the duty of the Procurement Administrator, in consultation with the Commission Staff, ComEd and AIU, 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 AIU would contract to purchase or hedge specific quantities of energy at fixed prices.

In the case of financial settlement, the IPA says ComEd or AIU 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." The swap contracts with ExGen and Ameren Energy Marketing, the IPA avers, are examples of a financially-settled contract. (IPA Plan at 34, 50)

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 AIU and the seller would execute an agreement, under which the seller transfers energy to ComEd via a PJM e-Schedule or to AIU via a MISO process. According to the IPA, ComEd or AIU would then directly pay the seller the agreed-upon fixed contract price for the specified amount of energy. (Id.)

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. (Id.)

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 per 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. (IPA Plan at 34, 51)

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. (IPA Pan at 51)

In contrast, the IPA recommends that the contracts to be procured through the RFP be settled financially for AIU volumes. The IPA states that the MISO market rules do not maintain the same credit requirements found in the PJM market; therefore, financial swaps are a standard method used by multiple entities within the MISO market for securing fixed cost pricing for loads. With the ability to settle prices financially without added premium, the IPA believes that a larger, more diverse, and competitive bidder pool will be interested in bidding on AIU requirements. (IPA Plan at 34)

The IPA indicates that it anticipates securing load for ComEd's and AIU's eligible 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 hopes to mitigate risk to ComEd's and AIU's eligible customers.

C. Capacity, Ancillary Services, Transmission Services

According to the IPA, **ComEd** will procure the capacity and ancillary services required by the Included Retail Customers from several sources. First, the existing ASFC's secure approximately one-third of these customers' capacity and ancillary services' requirements. Second, ComEd will procure the remaining capacity and ancillary services required by these customers directly from PJM-administered markets.

The IPA states that under the RPM program approved by the FERC and administered by PJM, ComEd is able to purchase capacity directly from PJM-administered markets. The IPA indicates that the RPM capacity prices for the June 2009 - May 2012 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 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. (IPA Plan at 51)

The IPA proposal is for 100% of **AIU's** monthly capacity requirements to be acquired for the first planning year, June 2009 through May 2010. The IPA indicates that in light of the MISO proposal to implement significant penalties associated with a capacity deficiency event, AIU will procure the entire forecasted requirement for the first planning year of this plan in advance of the that planning year. The IPA says MISO is proposing penalties of $80/kW-month for capacity deficiencies for all months of the year. According to the IPA, since AIU's purchases of non-summer capacity for the June 2008-May 2009 planning year suggest a market price of less than $0.50/kW-month, the risk of being deficient and subsequently penalized by MISO outweighs the risk of having excess capacity in non-summer months due to higher than anticipated switching. The IPA's proposal for 50% of the monthly capacity requirements to be acquired for the second planning year, June 2010 through May 2011. The IPA also proposes that 33% of the monthly capacity requirements be acquired for the third planning year, June 2011 through May 2012, and that 0% of the monthly capacity requirements be acquired for the fourth and fifth planning years, June 2012 through May 2014. (IPA Plan at 35-37)

According to the IPA, Module E of the MISO's Open Access Transmission and Energy Markets Tariff addresses resource adequacy. The IPA indicates that MISO's current Module E requires AIU to have capacity in an amount equal to its forecast of load plus a planning reserve margin. The IPA says the planning reserve margin is that of the relevant regional reliability organization or relevant state regulatory authority, but, in no case less than 12%. The IPA claims there is currently no enforcement mechanism or penalty provision in the MISO's tariff for not maintaining this level of capacity. (IPA Plan at 38)

The IPA states that the FERC has approved modifications to Module E to be effective June 1, 2009 such that AIU will be required to hold the higher of the reserve requirement as specified by an annual planning process undertaken by the MISO and the requirement of the relevant state regulatory authority. The IPA says these modifications require each load serving entity to provide an annual forecast of monthly loads and subsequently confirm on a month-ahead basis that each load-serving entity has enough capacity to meet or exceed its monthly peak load forecast plus its planning reserve margin. Although such approval did not contain any penalty provisions for non-compliance, the IPA says the MISO has subsequently filed additional modifications with FERC in order to seek penalty provisions. (Id.)

The IPA states that for demonstration purposes, the tables included in its proposed plan for AIU utilize the reserve margin of 14.3% that has been effective for the period June 2008 through May 2009 but the planning reserve margin beginning June 2009 has yet to be established. The IPA, therefore, recommends that the Commission authorize the IPA's procurement administrator, in consultation with the IPA, the Commission Staff, the procurement monitor, and AIU, to adjust the quantities of capacity to acquire in order to comply with the applicable planning reserve requirements. Furthermore, to the extent that 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 AIU to make up the difference through a supplemental procurement process. (Id.)

In addition to the acquisition of power and energy-related products, the IPA indicates that AIU 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 Transmission Service and Ancillary Services.

The IPA says Network Integrated Transmission Service ("NITS") is described in Section III of Module B to the MISO Tariff. The IPA indicates that AIU utilizes such NITS to reliably deliver capacity and energy from its Network Resources to its Network Loads, namely its Native Load obligations. According to the IPA, 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. The IPA claims AIU is required to acquire the necessary NITS in accordance with the tariff and the cost for this service is that established in the applicable MISO tariff schedules. (IPA Plan at 38)

D. Auction Revenue Rights

According to the IPA, as a load-serving entity ("LSE") in PJM, **ComEd** is granted the right to nominate Auction Revenue Rights ("ARRs") for specific paths to hedge transmission congestion risks. ComEd can nominate an amount of ARRs (in MWs) on any transmission path within PJM that sinks in the ComEd zone, up to its full allocation. Because other LSEs are also able to nominate ARRs of their choice in proportion to their load, the IPA indicates that ComEd is not guaranteed to actually receive all of the ARRs that it nominates. Given the historically low congestion between the ComEd zone and Northern Illinois Hub ("Ni-HUB") (where suppliers deliver power under the Master Agreements), the IPA says nominating other transmission paths would likely result in a higher expected value for ComEd's ARR rights. The IPA avers, however, that because the actual value of these transmission congestion rights can be volatile and can become negative, ComEd should attempt to monetize its ARR rights through a sale to other market participants thereby maximizing the value collected for such rights while limiting the risks to our customers. The IPA states that all proceeds and costs of such sales, including costs incurred to evaluate and execute such a strategy, should be passed to customers through ComEd's Rider PE. (IPA Plan at 51)

The IPA states that while ARRs are not a power and energy resource, the nomination and subsequent allocation of such rights to **AIU** generally serves to reduce the cost of congestion borne by AIU and, thus, ultimately by its customers. As part of the 2008 ARR allocation process at MISO, the IPA says AIU received a set of ARR entitlements and was awarded ARRs for the 2008 planning year. (IPA Plan at 38)

For future planning years, the IPA indicates that AIU should continue to actively participate in the MISO ARR nomination and allocation process, and should seek to nominate those ARRs with an expected positive value, recognizing that AIU may be required by the MISO to accept certain ARRs which do not have an expected positive value and further that though nominated, AIU ultimately may not be allocated all of the ARRs requested. (IPA Plan at 38-39)

The IPA believes AIU should retain the allocated ARRs and receive associated credits for its customers. The IPA also believes AIU 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 ("AMIL") balancing authority, AIU 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.

E. Load Balancing Procedures

Under the IPA's Plan, **ComEd** will utilize the PJM-administered day-ahead and real-time energy markets to balance its loads. On a daily basis, the IPA indicates that 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. The IPA states 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. (IPA Plan at 52)

When ComEd submits its day-after estimate to PJM, the IPA says that PJM will perform a similar settlement function in the PJM real-time market. The IPA states that 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. (Id.)

According to the IPA, upon Commission approval of its Plan, **AIU** will be entering into financial swap transactions to hedge the energy price risk of the portfolio. The IPA says 100% of the energy required to supply the load included in the Plan will be purchased in the MISO energy markets. The IPA indicates that AIU will forecast respective load requirements for each delivery day in accordance with industry standards and practices for each delivery day. The IPA expects that 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 explains 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 says MISO charges, including Revenue Neutrality Uplift and Revenue Sufficiency Guarantee payments, will also apply. (IPA Plan at 39)

F. Portfolio Rebalancing

The IPA says the PUA requires it to provide the criteria for portfolio rebalancing in the event of “significant shifts in load.” The IPA states that in the event that ComEd's or AIU’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 and AIU are required to promptly notify the IPA. The IPA indicates it will subsequently convene a meeting with ComEd or AIU, the Commission Staff, and 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 claims that over the term of its Plan, the most significant driver of load shifting levels is customer switching. If customer switching levels are significantly different from forecasted levels, the IPA believes a re-balancing of the portfolio may be warranted. (IPA Plan at 52)

G. Renewable Portfolio

The IPA points out that Section 1-75, subsection (c) of the IPA Act governs the acquisition of cost effective renewable energy resource standards for AIU and ComEd. For the June 1, 2009 through May 31, 2010 planning period, at least 4% of the total supply required to serve the load of eligible retail customers as defined in Section 16-111.5 of the PUA must be from such renewable energy resources. In addition, to the extent available, 75% of these resources should come from wind generation. Notwithstanding this requirement, the PUA limits the total amount of renewable energy resources acquired in this initial planning year such that the annual estimated average net increase due to the cost of the renewable energy resources included in the amounts paid by eligible retail customers in connection to electric service does not exceed 0.5% of the amount paid per kilowatt hour by those customers during the year ending May 31, 2007.

As provided for in the IPA Act, the actual amount of electricity (megawatt-hours) supplied by the electric utility to eligible retail customers in the planning year ending immediately prior to the procurement period (June 2007 – May 2008) is used as the basis for calculating this requirement. During that period, the IPA indicates that ComEd was projected to supply 39,109,000 MWh of electric energy to its eligible retail customers. The IPA says 4% of this value establishes a planning year renewable energy requirement of 1,564,000 MWh. During that same period, AIU was projected to supply 17,984,564 MWh of electric energy to their eligible retail customers. The IPA says 4% of this value establishes a planning year renewable energy requirement of 719,383 MWh. (IPA Plan at 40, 53)

The IPA indicates that the amount paid by ComEd's eligible retail customers for the electric service during the June 1, 2006 through May 31, 2007 planning year was $3,737 million. The amount paid by ComEd's eligible retail customers during the June 1, 2007 through May 31, 2008 planning year was $4,205 million. The IPA states that based on the provisions in the IPA Act, the Renewable Energy Resource Budget (“RRB”) for the 2009-2010 delivery period is $39.7 million for ComEd. The IPA also indicates that the amount paid by AIU's eligible retail customers for the electric service during the June 1, 2006 through May 31, 2007 planning year was $1,802 million. The amount paid by AIU's eligible retail customers during the June 1, 2007 through May 31, 2008 planning year was $1,810 million. According to the IPA, based on the provisions in the IPA Act, RRB for the 2009-2010 delivery period is $16.6 million for AIU. The IPA says the RRB covers the cost of the renewable resources required by the RPS and all costs incurred related to their procurement and the quantity of renewable resources actually purchased can be limited by the RRB. (Id.)

The IPA proposes for ComEd and AIU to 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 IPA asserts that 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. The IPA claims that the purchase of RECs to satisfy the RPS requirements is preferable because RECs trading markets are more robust and liquid than those for the acquisition of physical renewable energy resources in this Plan year; the renewable energy market is uncertain due to the scheduled expiration of the federal Production Tax Credit at the end of 2009; and long-term commitments and significant lead times are generally required for physical delivery of renewable energy. (IPA Plan at 40-41, 53-54)

In the IPA's view, the option of contracting for physical wind energy supply is not viable in this plan year and purchasing RECs is preferable at this time. The IPA states that the REC purchases are subject to:

1. The statutory limit on the annual cost of meeting the renewable requirement;
2. The statutory requirement that at least 75% of the renewable energy shall be from wind generation;
3. The statutory preference for renewable resources located in Illinois, which extends through June 1, 2011; and
4. The uncertain size of future loads to be served through IPA procurement plans.

According to the IPA, the interplay of these four factors determines how REC procurement must be conducted in order to promote the development of a robust renewable energy industry in Illinois, while assuring reasonable costs to consumers. (IPA Plan at 54, 41)

The IPA claims that the REC bidding in 2008 resulted in consumers paying high premiums for in-state RECs relative to comparable bids from other states. In order to avoid repeating this outcome, the IPA believes the Procurement Administrator should be directed to establish benchmark REC prices, and to reject bids priced above the benchmarks. The IPA asserts that the benchmarks should be set at levels that consider relevant market prices and the economic development benefits of in-state resources. The IPA contends that the benchmark prices should be confidential, but shall be provided to, and will be subject to, Commission review and approval prior to solicitations of REC bids.

Section 16-111.5(e)(3) of the PUA addresses benchmarking:

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

The IPA believes benchmarking, where market prices can be verified, is consistent with the intent of the IPA Act, and says benchmarking of all products purchased pursuant to a procurement plan is required by the PUA. (IPA Plan at 41, 54)

The IPA states that long-term contracting for RECs as well as for underlying renewable energy supply can support the development of a vibrant renewable energy industry while helping to manage price risks and providing the lowest costs to customers. The IPA asserts that these long-term procurement issues will be fully considered and addressed by the IPA in future procurement plans. The IPA says that if a new statute becomes law prior to the procurement of RECs under this plan that provides for benchmarking of long-term contracts for renewable energy supply and/or RECs, the Procurement Administrator should consult with the IPA, the Commission, ComEd and AIU and recommend a method, consistent with all applicable statutes, to allow contracts of greater duration than one year to be considered for incorporation into bid solicitations. (Id.)

According to the IPA, sufficient RECs to comply with the quantities established by 1-75(c)(1) of the IPA Act should 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. The IPA says such acquisitions of renewable energy credits should be memorialized with a Master Renewable Energy Certificate Purchase and Sale Agreement.

H. Compliance Tracking

The IPA emphasizes that the acquisition of renewable energy credits in finite amounts equal to the statutory requirement ensures compliance. To the extent that the load data from the prior 12-month period which forms the basis for the required volume is not available at the time of the initial solicitation, the IPA says ComEd and AIU will use forecasted load data to estimate the requirement. When such data does become available, the IPA says ComEd and AIU should make the appropriate adjustment to their portfolio of renewable energy credits, including a reallocation between the Illinois utilities if appropriate, and report such adjustments and results to the IPA. (IPA Plan at 55, 42)

According to the IPA, PJM Environmental Information System's ("EIS") Generation Attribute Tracking System ("GATS") and the Midwest Renewable Energy Tracking System ("M-RETS") will be utilized to independently verify the location of generation, resource type and month and year of generation. The IPA states that 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. The IPA says M-RETS tracks renewable energy generation and assists in verifying compliance with individual state/provincial RPS requirements or voluntary programs, typically for generators located in the MISO footprint and other RTOs outside of PJM. (IPA Plan at 55)

The IPA proposes that RECs delivered to AIU be measured by metering equipment installed, maintained, replaced, tested, and read pursuant to Attachment R-4, Section 10 (Metering) of the MISO Open Access Transmission and Energy Markets Tariff ("TEMT") or similar as approved by ComEd and AIU. The IPA says all costs associated with the installation, change, or administration of metering equipment and should be borne by the supplier of the RECs. Under the IPA's proposal, the seller will be responsible for timely monthly submission of accurate, complete, and verified metering data to AIU, which will have the right to audit such submissions. (IPA Plan at 42)

The IPA also proposes for each agreement by ComEd and AIU for the acquisition of a REC to have a specified term. The IPA says that all RECs used by ComEd and AIU should comply with the statutory requirements and should be retired in compliance with 1-75(c)(4).

According to the IPA, Section 1-75(c)(3) of the IPA Act requires that cost effective renewable energy resources be procured from facilities in the State of Illinois until June 1, 2011. The IPA asserts that if sufficient cost effective resources are not available in the State of Illinois, they shall be procured next from states that adjoin Illinois and finally, if unavailable from such other states, they shall be acquired elsewhere. Based on this requirement, the IPA proposes for the RFP evaluation to be completed as follows:

1. Determination of REC requirement. As provided for in the IPA Act at least 4% of the actual amount of electricity (megawatt-hours) supplied by the electric utility to eligible retail customers as determined in the planning year ending immediately prior to the procurement period (June 2008 – May 2009) is used as the basis for calculating the REC requirement.

2. Determination of Cost effectiveness. A portfolio of RECs shall be deemed to be cost effective if the portfolio's cost for is equal to or less than 1.0% of the amount paid per kilowatt hour by those customers during the year ending May 31, 2007, multiplied by the kWh consumption of those same eligible retail customers, as detailed in Section1-75(c)(2)(b) of the IPA Act.

3. 75% Minimum Wind Test Adjustment. At least 75% of the RECs used to meet the standards shall come from wind generation. If the portfolio is made up of 75% wind, the bid evaluation is completed.

(IPA Plan at 42, 55)

In the Commission's view, whether the IPA's "75% wind" adjustment is a correct interpretation and application of the statute and the Commission's Orders in Dockets 07-0527 and 07-0528/0531 (cons.) is an open question. However, since no parties filed objections to it, the Commission will not impose any modifications to the Plan on this issue in the instant Order. The Commission believes that this issue should be further evaluated in future plans and proceedings.

I. Contingencies

The IPA has developed a plan to procure power and energy for ComEd's and AIU's "Included 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 says the proposed plan is substantially based on the contingency plan as specified in the IPA Act and Section 16-111.5 (e)(5)(i) of the PUA. The IPA also describes a plan to procure power and energy in the event of a default under an existing ASFC. (IPA Plan at 42, 55-56)

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 for ComEd or AIU to immediately notify the IPA, Commission Staff, and the Procurement Administrator that another procurement event will 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 this plan. The IPA proposes for the Commission Staff and its monitor to 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 replacement plan would continue to seek energy for only standard block products. The IPA says all ancillary services, capacity and load balancing requirements would continue to be procured through either the PJM or the MISO 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 and by AIU through MISO-administered markets. The IPA says that notwithstanding, if a particular required product is not available through PJM or MISO, it will 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, the IPA proposes for ComEd or AIU to procure the required power and energy directly from the PJM or MISO administered markets. The IPA says 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 or MISO administered markets, IPA says it will 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 for a meeting of the Procurement Administrator, the Procurement Monitor, and the Commission Staff to 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.

Should a procurement event be required subsequent to the initial event, the IPA proposes for the Procurement Administrator and the Procurement Monitor to separately submit a confidential report to the Commission within two business days after opening the sealed bids. The IPA proposes that 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.

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 for ComEd or AIU to procure the required power and energy requirements for the eligible load through the PJM or MISO administered markets, respectively. 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 or MISO, the IPA says ComEd or AIU will purchase that product through the wholesale market. (IPA Plan at 43, 56)

VII. OBJECTIONS, RESPONSES AND REPLIES; COMMISSION CONCLUSIONS

A. Single Procurement Event

For the upcoming 2009 procurement period, the Plan proposes to procure the recommended standard wholesale products through the use of a single procurement event. (IPA Plan at 19)

1. Parties' Positions

ComEd supports the proposal by the IPA to procure the recommended standard wholesale products through the use of a single procurement event. However, ComEd complains that the IPA also states that a single procurement event increases portfolio risk and the potential for the exercise of market power. (IPA Plan at 2, 19) ComEd expresses concerns about these statements being in the Plan because ComEd does not concur and also because ComEd believes they contradict the IPA's recommendation. (ComEd objections at 2-3)

ComEd states that the IPA is proposing a single procurement event for 2009, noting that in the Executive Summary portion of the Plan the IPA indicates that it would consider the use of multiple procurement events in future procurement plans. However, ComEd claims the IPA neglected to remove or modify the language about portfolio risk and the exercise of market power.

ComEd agrees that it is appropriate for the IPA to analyze and consider whether or not a single procurement event increases portfolio risk or facilitates the exercise of market power; however, ComEd contends such an analysis has not been done in this Plan. ComEd asserts that the IPA's brief statements ignore the fact that in past litigation concerning procurement in Illinois, neither the Commission nor the FERC has found that single annual procurement events increase risk or facilitate the exercise of market power. ComEd also contends that the IPA overlooks the fact that all bidders must have market-based rate authority from the FERC. ComEd says FERC regulations and federal law provide layers of protection against the exercise of market power in such circumstances.

At page 3 of its Objections, ComEd offers specific modifications to the Plan intended to resolve this issue. With ComEd's clarifications, the Plan would state that the "IPA intends to evaluate whether" a single procurement event increases portfolio risk and the potential for the exercise of market power.

In its Response to Objections, **the IPA** agrees this section could have been clearer; however, the IPA believes that the statements are important with any future transition to multiple procurement events. The IPA provides specific proposed language intended to clarify that its proposal relates to future procurement events, which is the same as ComEd's proposed language.

In its Response to Objections, **RESA** opposes what it describes as ComEd's attempt to remove from the Plan any discussion of increasing the frequency of procurement events. (RESA Response at 1-5) RESA states while it is true that , such an analysis has not been done in this Plan, the statement that the IPA intends to consider the issue in future plans and that it is doing so because of its concern that single procurement events increase portfolio risk and the potential for the exercise of market power, puts all parties on notice of its intentions and the reasons for those intentions. RESA says that understanding the IPA's concerns and its means of addressing those concerns will enable all parties to begin to prepare for the next procurement plan by gathering evidence and studies relating to the frequency of procurement events and their effects on portfolio risks and the exercise of market power.

RESA objects to what it describes as ComEd's proposal to strike the language in the Plan discussing the rationale behind moving toward more frequent procurement events. RESA says such procurement, if paired with a rate mechanism that promptly translates these new wholesale rates into retail rates, would move toward a market-based procurement that uses similar timing of acquisition and contract lengths used in the competitive marketplace. RESA contends the resulting prices should be more reflective of market prices and thus provide advantages to the competitive electric market in Illinois.

In its Response to Objections, **Staff** indicates that it agrees with ComEd's proposed changes to the Plan. Staff says the IPA presents no data or even a theory to support its contention. As an alternative, Staff suggests the Commission's order adopting the Plan should make clear that it is not making any findings at this time associated with the Plan's contention that single procurement events increase portfolio risk and the potential for the exercise of market power.

2. Commission's Conclusion

ComEd and Staff object to certain language contained in the IPA's Plan that suggests using a single procurement event rather than multiple procurement events increases portfolio risk and the potential for the exercise of market power. ComEd proposes certain modifications, which are acceptable to Staff and the IPA, but not to RESA.

It appears to the Commission there is no dispute that for the upcoming 2009 procurement period, a single procurement event should and will be used. Additionally, the Commission finds there is not sufficient analysis in the Plan or other filings to support a finding with regard to what, if any, impact the frequency of procurement events has on the portfolio risk or the exercise of market power. That is, in the Commission's view, no conclusions can be drawn at this time regarding the advisability of performing multiple procurement events in a procurement year.

With ComEd's clarifications, accepted by the IPA and Staff, the Plan would not state that a single procurement event increases portfolio risk and the potential for the exercise of market power. Rather, the Plan would state that the IPA intends to evaluate whether a single procurement event increases portfolio risk and the potential for the exercise of market power. These modifications appear reasonable and should be adopted. To the extent future procurement plans address the issue, the Commission will give such discussions or proposals due consideration.

B. Demand-Side Initiatives

1. Parties' Positions

ComEd states that the IPA does not propose the use of any energy efficiency or demand-response measures as components of the 2009 procurement event. However, ComEd expresses concern that the IPA does state its intent "to use internal and external experts to comprehensively evaluate the inclusion of robust demand-side initiatives as integral components of a balanced least cost resource portfolio" in future plans. ComEd says the IPA also indicates its intent to involve "market participants and other interested parties" in this process. (ComEd Objections at 3-4)

ComEd complains that the IPA does not make clear what types of programs or resources the IPA includes within the term "demand-side initiatives." ComEd interprets the term "demand-side initiatives" to mean "demand-response measures" as that term is referred to in the PUA (see Section 12-103(c)). If this interpretation is correct, ComEd has no objections.

In this regard, ComEd offers specific "revisions" intended to clarify the Plan, whereby the word "demand" would be changed to "demand-response" and the terms "demand-side resources" and "demand-side initiatives' would be changed to "demand-response measures." (ComEd Objections at 4, citing IPA Plan at 2-3)

In its Response to Objections, pages 2-3, **the AG** states that there is no reason to peremptorily exclude other demand-side resources – such as energy efficiency – from consideration in future procurement planning processes. According to the AG, prohibiting consideration of energy efficiency in future power procurement plans would deprive consumers of a low risk, cost-effective alternative to supply. In addition, the AG asserts that investment in demand-side measures, beyond those required by the Energy Efficiency Portfolio Standard, will reduce price risk and save money for consumers. The AG urges the Commission to reject ComEd's attempts to narrow the scope of future planning processes in a manner that excludes consideration of resources that could help to ensure adequate, reliable, affordable efficient and environmental sustainable electric service at the lowest total cost over time, taking into account any benefits of price stability.

In its Response to ComEd's objections, **Staff** discusses, but ultimately takes no position, with respect to whether the IPA should broadly consider energy efficiency as well as demand response initiatives, limit its evaluation of "demand-side initiatives" to demand response initiatives (as proposed by ComEd), or consider neither energy efficiency nor demand response initiatives. (Staff Response at 8-9)

In its Response to Objections, pages 2-3, **the IPA** indicates that it agrees with the modifications proposed by ComEd.

2. Commission's Conclusion

With respect to the 2009 procurement event, it appears to the Commission that there is no substantive dispute between the parties.

With respect to future procurement plans after 2009, the IPA agrees with ComEd's proposed modifications, while the AG does not.

Given the limited record on this issue in this proceeding, the Commission believes it would be premature at this time to impose modifications that would prohibit consideration by the IPA of certain types of demand-side initiatives when developing future procurement plans, and the Commission makes no findings with respect thereto. The parties are free to present their respectively proposals and objections in such future proceedings, within the framework of the statute.

C. Long-Term RECs and Renewable Supply

1. Parties' Positions

The IPA's Procurement Plan does not intend to procure any physical renewable supply or any long-term renewable energy credits ("RECs"). (IPA Response to Objections at 3) It appears that for future procurement events, beyond the 2009 procurement, the IPA may give consideration to acquiring RECs and renewable supply with terms greater than one-year.

The IPA appears to qualify its intentions for the 2009 procurement, however, such that if there is a change in the law prior to the procurement of RECs under the Plan being considered in this proceeding, the Procurement Administrator will consult with the IPA, the Commission and the utilities to allow consideration of contracts of greater duration than one year.

According to **ComEd**, the IPA indicates that if certain legislation is enacted providing for the benchmarking of long-term contracts for renewable supply and/or RECs, the Procurement Administrator will recommend a method, "consistent with all applicable statutes", to incorporate bids for such long-term contracts to be considered.

ComEd says that subsections 16-111.5(d)-(g) of the PUA set out a precise process for procuring electricity, including renewables and RECs. ComEd believes there are a number of issues associated with long-term purchases of RECs, including risks inherent in long-term contracts and how to establish appropriate pricing in a market with no long-term price visibility. ComEd claims it would have fully investigated these issues as part of the process before the Commission, and contends that such issues would need to be investigated in any process the IPA proposes. ComEd states that so long as the process that the Procurement Administrator recommends for procuring any long-term renewable products complies with this statutory process, ComEd does not object at this time. (ComEd Objections at 4-5)

Staff indicates it is not fundamentally opposed to long-term contracting for RECs. However, Staff "has some concerns with the concept and is not as sanguine about its efficacy as the IPA appears to be." (Staff Response to Objections at 10-11) Staff expresses concern, given the IPA Act's annual budget constraint and its hierarchy of multiple selection criteria for renewable resources, that a multi-year approach would appear to require inter-year allocations of the budget and other parameters. Without such allocations between years, Staff claims it is more likely that the total REC budget could be spent improving upon tertiary and quaternary goals dealing with location, before fully achieving the primary and secondary goals of the IPA Act. Staff does not characterize this as an insurmountable obstacle, but merely as a detail that must be addressed if multi-year REC contracts are to be sought.

If the plan is to offer one-year and multi-year contracts at the same time, and the winning bid is based on a levelized-cost per unit basis, Staff believes this may be an inappropriate comparison which would tend to lock in higher prices for longer periods of time, rather than lead to a lowering of prices over time. Staff provides an example intended to illustrate its concern. Staff is concerned that the long-term result would be that the IPA would spend more for RECs than if it only allowed one-year contracts. (Staff Response to Objections at 10-11)

According to Staff, there are factors in favor of projecting a downward trend and there are factors against such a trend. Staff says the main factor in favor of a downward trend is that high prices tend to provide an incentive for increases in investment and in supply. All else constant, Staff claims an increase in supply leads to a reduction in price. Staff believes that current REC prices reflect a short-term scarcity in renewable capacity and is allowing supra-normal profits. Staff suggests that as more capacity is added in reaction to these high REC prices, market prices for RECs should decrease to a level consistent with normal profits.

According to Staff, other factors that may lead to further reductions in REC prices are (1) increases in energy prices, (2) increases in Federal subsidies for renewable power, and (3) further improvements in renewable technologies. Staff claims these factors increase the profitability of renewable resources, again leading to an increase in renewable investment and capacity, placing downward pressure on REC prices. Staff states that on the other hand, a major factor that may lead to higher REC prices over time are that aggressive renewable portfolio standards in the U.S. and around the World are placing increasing pressure on existing capacity of renewable resource manufacturers (e.g. wind turbine producers), on transmission systems, and ultimately on the ability of supply to keep up with demand. In Staff's view, if REC prices do not fall over time, then one might also expect that policy makers would modify current renewable portfolio standards. It is Staff's expectation that long-run contracts competing head-to-head with short-run contracts for the same time periods will have the perverse effect of locking in high REC prices and keeping REC prices higher than they otherwise would be. (Id.)

Staff acknowledges that there may be value to ratepayers in the IPA's conducting RFPs specifically for new renewable capacity, and Staff is interested in working with the IPA and other interested parties in exploring that concept for inclusion in future procurement plans. It is Staff's expectation that such a process will lead to incremental renewable capacity if and only if the IPA allows enough lead time for winning bidders to subsequently: arrange financing, order equipment, obtain necessary regulatory approvals, obtain interconnection approval from the relevant transmission provider, obtain land or land right-of-ways, prepare the site, build the renewable facilities, test the facilities, and perform any other time-consuming activities that must be accomplished before commercial operation can begin.

In Staff's view, it seems unrealistic for long-run contracts for renewable power or RECs to benefit ratepayers unless they are specifically geared toward capacity additions; but, from start to finish, capacity additions take many months to bring to full fruition. According to Staff, long-run contracts should be geared toward the future and should not be considered viable substitutes for one-year REC contracts for June 2009-May 2010. Staff notes that the IPA's plan does not mandate the procurement administrator to seek multi-year REC contracts. (Id. at 12-13)

In its Response to Objections, Staff reiterates the position stated in its Objections. Staff opposes long-term RECs being included in the Plan.

In its Response to Objections, **the IPA** notes that ComEd does not propose any specific amendments or "redline changes" to the Plan. (IPA Response to Objections at 3) The IPA believes the Plan is clear in this respect, and recommends that no modifications be made to the Plan at this time.

Similarly, the IPA states that because Staff makes no recommended modifications to the Plan with respect to the term of the contracts for RECs, the IPA recommends no modifications be made to the Plan at this time. (Id. at 9)

In its Response to objections, **the AG** states that while there may be downside risk associated multi-year contracts, it seems unlikely that prices for wind-generated electricity will fall at the rate assumed by Staff. In fact, the AG suggests the opposite may be true. The AG says electricity from wind projects being developed today is likely to be less expensive to produce than electricity from projects developed in the future -- because wind developers, quite logically, develop the most cost-effective sites first. The AG claims that increased demand for renewable resources (as a result of state and, possibly federal, Renewable Portfolio Standards) will continue to put upward pressure on prices. (AG Response to Objections at 4-5)

According to the AG, the key to reducing prices for electricity from wind resources is to increase supply. The AG believes that will be difficult in today's credit market. Without long-term contracts, wind developers will find it difficult to attract financing. The AG suggests that if the IPA were to accept bids for long-term contracts during the Spring of 2009, it would be easier to finance wind projects and to get them on line before the Production Tax Credit ("PTC") expires. The AG asserts that consumers could benefit significantly from multi-year REC contracts that reflect savings from the PTC and the lower costs of producing electricity from the (relatively) more cost-effective sites now under development.

2. Exceptions and Replies

The proposed order contained language that would generally prohibit the use of RECs and renewable energy sources with terms greater than one year. The proposed order, however, contained certain language that would allow the use of multi-year or long-term renewable resources during the June 2009 to May 2010 acquisition period if there were a change in law that explicitly required the use of such multi-year or long term resources.

The **AG** takes exception to the language in the proposed order. Under the AG's proposal, if there is a change in law that would require "benchmarking" of renewable resources during the June 2009 to May 2010 acquisition period, then the IPA would be permitted to use multi-year REC contracts for that period. (AG BOE at 4-6) The AG states that that the General Assembly recently passed and sent to the Governor legislation, identified as Senate Bill 1987 ("SB 1987"), which amends Section 1-75(c)(1) of the IPA Act to expressly require the use of benchmarks in connection with the procurement of renewable energy resources. The benchmarking issue is addressed in Section VII.D below.

In its RBOE, **ComEd** asserts that the portions of SB 1987 that amends Section 1-75(c)(1) of the IPA Act referenced by the AG imposes no limitation on the term of renewable contracts to be benchmarked. ComEd claims it does not require the benchmarking of – let alone the acquisition of – long-term renewable resource contracts. According to ComEd, even if it were currently effective, SB 1987 would be no reason to overturn the recommendation in the proposed order that long-term contracts not be acquired this cycle and no reason to alter the IPA's Plan to acquire long-term resources in the 2009 event only if a new statute becomes law prior to the procurement of RECs under this plan that provides for benchmarking of long-term contracts for renewable energy supply and/or RECs. (ComEd RBOE at 2-3)

Staff's RBOE argues that the AG presents no basis to change the conclusion contained in the proposed order regarding the procurement of long-term renewable resources at this time. Staff notes that SB 1987 does not explicitly require the use of multi-year or long-term renewable resources during the June 2009 to May 2010 acquisition period. Staff also emphasizes that SB 1987 has not yet become law and, if it is signed by the Governor, will not become effective until June 1, 2009. Staff also maintains that the neither the AG nor SB 1987 has addressed the many concerns Staff has identified regarding the use of multi-year or long-term renewable resources. (Staff RBOE at 4-5)

3. Commission's Conclusion

The Commission's review of the IPA's procurement Plan for 2009, filed October 21, 2008, indicates that the IPA anticipates utilizing one-year RECs to meet the statutory requirements for the 2009 procurement. It appears that for future procurement events, the IPA may give consideration to acquiring RECs and renewable resources with terms greater than one-year.

The IPA appears to qualify its intentions for 2009, however, such that if there is a change in the law prior to the procurement of RECs under the Plan being considered in this proceeding, the Procurement Administrator will consult with the IPA, the Commission and the utilities to allow consideration of contracts of greater duration than one year.

Both ComEd and Staff express concern over the use of long-term RECs, particularly in the short-run. Staff seems more concerned and explicitly objects to the use of multi-year RECs during the 2009 procurement event. Because the IPA's Plan does not mandate the use of multi-year RECs, and provided all RECs comply with the provisions in subsections 16-111.5(d)-(g) of the PUA, ComEd does not specifically object to the content of the IPA's Plan. In contrast, the AG seems to favor the use of long-term RECs and also suggests the acquisition of long-term RECs during the 2009 procurement event is desirable.

Having reviewed the filings of the parties, it appears to the Commission that there are potential risks as well as potential benefits associated with long-term renewable contracts. What is unclear at this point is whether the potential risks exceed the potential benefits; there is not sufficient analysis in the record to permit an informed decision on this issue. Thus, in an effort to protect utility ratepayers, the Commission finds that for the 2009 Procurement event, the IPA is not permitted to undertake the acquisition of multi-year or long-term renewable resources.

The only allowable exception would be if there is a change in law that would require the use of multi-year or long-term renewable resources during the June 2009 to May 2010 acquisition period. The Commission agrees with Staff and ComEd that Senate Bill 1987, even if signed into law, does not contain such a requirement.

These conclusions are not intended to foreclose the consideration of multi-year or long-term renewable resources in future procurement periods. To the contrary, the Commission encourages the parties to continue to investigate and, to the extent appropriate, pursue the possibility of acquiring multi-year or long-term renewable resources in future procurement periods.

D. REC Benchmarks

Section 16-111.5(e)(3) of the PUA states:

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

The Plan sets forth guidelines to use benchmarks to measure whether to accept or reject Renewable Energy Credit ("REC") bids. (IPA Response to Objections at 7; IPA Plan at 41)

1. Parties' Positions

Staff does not believe that benchmarks are required as a matter of law for RECs under the PUA. (Staff Objections at 12) According to Staff, Section 16-111.5(e)(3) of the PUA provides that "the procurement administrator, in consultation with the Commission staff, Agency staff, and the procurement monitor, shall establish benchmarks for evaluating the final prices in the contracts for each of the products that will be procured through the procurement process." Staff states that Sections 75-(c)(1) and (3) of the IPA Act provide that certain priorities be given to wind and to RECs for generators in Illinois, in adjoining states and then in other states. Staff believes that benchmarks could conflict with and be inconsistent with these priorities.

Staff also indicates that Section 75(c)(2) of the IPA Act contains a rate impact test for RECs that operates as an independent benchmark, whereby REC purchases are constrained to a 0.5% rate impact. Again, Staff believes benchmarks could conflict with this constraint or render it superfluous.

Staff contends that benchmarks could obstruct achievement of objectives such as meeting a 4% of energy goal if achievable within the rate impact test (0.5% of amounts paid for year ending May 31, 2007 plus 0.5% of amounts paid for year ending

May 2008, or 1% of amounts paid for year ending May 31, 2007) and interfere with complying with the REC priority scheme established in the PUA and IPA Act. Thus, Staff does not believe that the Legislature intended to mandate benchmarks for RECs given the potential conflicts with the other goals and priorities.

Staff also expresses concern that adding any benchmark into the selection process would potentially counteract the effect of the other special renewable/REC requirements. (Staff Objections at 13) Staff suggests that the use of benchmarks could reduce the procurement administrator's ability to purchase the required (or target) level of RECs, even if the IPA Act's spending limit had not yet been met. Staff also asserts that the use of benchmarks could reduce the procurement administrator's ability to purchase at least 75% wind RECs, even if the IPA Act's spending limit had not yet been met.

Furthermore, depending on if and how much of a benchmark adder is assigned to in-state resources, Staff claims benchmarks could prevent the procurement administrator from purchasing more Illinois RECs, even though the IPA Act's spending limit had not been met. The same argument applies to adjoining state RECs, which are also favored by the IPA Act, just under in-state resources. Staff says the examples it cites would all reduce the total amount spent on renewable power or RECs, but at the "expense" of not satisfying the other objectives in the IPA Act (namely, the preferences stated for wind, Illinois, and adjoining state resources).

Staff does not believe it would be appropriate to create benchmarks for renewable energy resources ("renewables") or RECs without, at a minimum, some showing of need given the cost caps and preferences contained in the IPA Act for renewables and RECs. (Staff Objections at 14) Staff says the IPA has identified what it considers unacceptably high premiums for certain RECs as the basis for imposing benchmarks on RECs. Staff states that while it understands the IPA's concern, addressing that concern through benchmarks presents a risk of interfering with the preferences and priorities established by the General Assembly.

Staff believes it is possible that benchmarks could be developed which balance the IPA's concern with the other goals and preferences stated in the IPA Act. Staff states that since the Plan provides that proposed REC benchmarks will be subject to Commission review and approval, Staff would not object to this aspect of the Plan if it is clear that the Commission can consider these competing interests when it reviews the benchmarks. Staff further notes that even if benchmarks for RECs are established and approved, the concept of REC benchmarks must be subject to reconsideration in future procurement plans based on the results achieved using those benchmarks. (Staff Objections at 14)

Section 16-111.5(e)(3) PUA states, in part, "The benchmarks shall be based on price data for similar products for the same delivery period and same delivery hub, or other delivery hubs after adjusting for that difference." Staff claims that price data for RECs are relatively scarce and the data that is available shows that the prices of RECs appear to be highly idiosyncratic, and are probably driven by the local jurisdiction's own renewable portfolio requirements. In Staff's view, employing benchmarks based on limited and idiosyncratic price data may not fit within the spirit or the letter of the Illinois statute.

The proposal to consider "the economic development benefits of in-state resources" is also of concern to Staff. Staff asserts that it is highly speculative if not arbitrary for the Commission to project economic development benefits of in-state resources.

For the above reasons, Staff is reluctant to advise the Commission to approve the adoption of REC benchmarks at this time. (Staff Objections at 15)

In its Reply to the IPA's Response to Objections, which is discussed immediately below, Staff says that if the IPA is arguing that benchmarks are legally required under the PUA, the Commission should reject such an assertion. (Staff Reply to Responses at 5-10) Staff insists that the language in the PUA concerning benchmarks must be read in conjunction with other provisions of Public Act 095-0481. Staff believes the PUA should not be interpreted to mandate benchmarks for RECs given the very specific goals and priorities otherwise established by the Legislature for renewable energy and RECs, and the obvious potential for REC benchmarks to conflict with and prevent achievement of those goals and priorities.

Staff is concerned that adding any benchmark into the REC selection process would potentially counteract the effect of the other special renewable/REC requirements. Staff also says that the IPA's Response to Objections fails to address the argument advanced by Staff that benchmarks are not legally required for RECs, given the specific renewable/REC requirements otherwise established in the PUA and the IPA Act.

Staff also suggests that the IPA's argument may indicate its view that the Plan mandates, rather than allows, benchmarks regardless of the impact of the actual benchmarks on the special renewable/REC requirements set forth in the PUA and IPA Act – so as to effectively deny the Commission the ability to consider these potentially competing interests. In Staff's view, the Commission should not accept a Plan that incorporates a proposal to develop benchmarks for RECs if that Plan denies the Commission the ability to consider the impact of such benchmarks on other statutorily prescribed goals and preferences. Staff asserts that accepting the Plan under such circumstances would inappropriately conflict with the statutorily established goals and priorities for RECs, and the IPA's argument does nothing to explain why it would be appropriate to ignore those statutorily prescribed goals and priorities.

According to Staff, another possible interpretation of the IPA's "shall be" argument, when considered with its failure to confirm the interpretation of the Plan specifically identified by Staff, is that the IPA rejects Staff's interpretation and believes the Plan as proposed requires the construction of benchmarks for RECs regardless of the availability of adequate data. Staff contends that the Commission should not accept the proposal to establish benchmarks for RECs under such conditions.

Staff notes that the PUA provides that "The benchmarks shall be based on price data for similar products for the same delivery period and same delivery hub, or other delivery hubs after adjusting for that difference." 220 ILCS 5/16-111.5(e)(3) Staff also maintains that price data for RECs are relatively scarce and the data that is available shows that the prices of RECs appear to be highly idiosyncratic, and are probably driven by the local jurisdiction's own renewable portfolio requirements. In Staff's view, employing benchmarks based on such limited and idiosyncratic price data may not fit within the spirit or the letter of the Illinois statute, and the Commission should not accept the proposal to develop benchmarks for RECs, unless it is clear that the development and acceptance of benchmarks are subject to the availability of adequate supporting data.

Staff recommends that the Commission either reject the use of REC benchmarks for the upcoming procurement events or that the Commission make it clear in its order that (1) before recommending any REC benchmark, the procurement administrator(s) should take into account the availability of verifiable market price data and (2) the above-described competing interests associated with using a REC benchmark shall be considered when the Commission reviews any proposed REC benchmarks. (Staff Reply to Responses at 9-10)

In its Response to Objections, **the IPA** indicate that it appreciates Staff's concerns regarding the use of appropriate benchmarks, and the IPA believes that Staff's concern regarding the availability of some benchmark data is well-taken. The IPA states that Section 16-111.5(e)(3) of the PUA states specifically that all contracts for the products procured through the procurement process, including renewable energy, shall be evaluated according to benchmarks established by the Procurement Administrator, in consult with the Commission, IPA Staff, and the Procurement Monitor.

According to the IPA, the creation of the benchmarks, and the evaluation of the REC bids with respect to the benchmarks, will be made in cooperation with these participants at the appropriate time. The IPA says that because Staff makes no recommended modification to the Plan with respect to the reliance on benchmarks to evaluate bids, the IPA recommends no modifications be made to the Plan at this time. (IPA Response to Objections at 7-8)

In its Response to Objections, **the AG** says it recognizes the challenges involved in setting benchmarks for renewable energy bids – but believes it is necessary to surmount those challenges to prevent bidders from exploiting the statutory preference for in-state resources in the manner that occurred in 2008. The AG claims that other states have used benchmarks to avoid similar problems. The AG asserts that the New York State Energy Research and Development Authority ("NYSERDA") has established benchmarks that reflect the expected costs of available new renewable generation and, in some instances, used those benchmarks to reject bids. The AG further asserts that the NYSERDA separately considered the economic development value of renewable energy projects along with price in evaluating which projects to offer contracts.

The AG believes either of these approaches could be adapted for use in Illinois. The AG states that in the absence of readily available external market data, a realistic market-based benchmark for in-state projects could be derived using Illinois-specific data. The AG suggests that such benchmarks might be based on the actual cost of equipment and labor needed to develop renewable energy projects in Illinois, with a rate of return that is adequate to attract financing.

In the AG's view, it would not be appropriate to base benchmarks on short-term spot prices – such as those presented in Appendix A to Staff's response. The AG agrees with Staff's view that employing benchmarks based on such limited and idiosyncratic price data may not fit within the spirit or the letter of the Illinois statute. The AG suggests that the procurement administrator should develop realistic benchmarks that reflect the price that an Illinois renewable energy generator would be expected to charge in an efficient market – something approximating the notion of long run marginal cost.

With respect to Staff's legal concerns, the AG agrees with Staff's view that neither the IPA Act nor the PUA require the use of benchmarks to evaluate renewable energy bids. However, the AG believes that Section 1-759(c) of the IPA Act and Section 16-111.5(e)(3) of the PUA provide ample authority for using benchmarks to evaluate REC bids to prevent bidders from exploiting the statutory preference for in-state resources. The AG contends that the 2009 procurement process should incorporate benchmarks to make sure that in consumers don't end up paying a large premium for in-state renewable resources. The AG believes there is no legal impediment to doing so now – and claims doing so may soon be mandatory. The AG expresses concern that failure to address this problem could make it impossible to meet the RPS targets within the statutory spending caps. (AG Response to Objections at 5-6)

In its Response to Objections, **ComEd** expresses support for the Staff's statutory and practical concerns relating to the establishment of REC benchmarks. ComEd states that while this matter has been largely delegated to the IPA, Staff, the Procurement Monitor and the Commission, ComEd understands that it was primarily due to these same concerns that benchmarks were not developed for RECs during the last procurement event in Docket Nos. 07-0528/07-531 (cons.). ComEd indicates it would not object if these parties wish to reconsider whether it is possible and advisable to establish such benchmarks. In ComEd's view, most important is the involvement of Staff, the Procurement Monitor and the Commission in the process, and the IPA has already indentified the involvement of these parties. (ComEd Response to Objections at 2)

In its Reply to the IPA's Response to Objections, ComEd indicates that it does not believe that separate benchmarks for renewable products are legally required under

Section 16-111.5(e)(3) of the PUA. In ComEd's view, that section appears to apply only to standard wholesale energy products and not to RECs or other types of renewable resources. ComEd says the benchmarks are to be based upon price data for similar products from “the same delivery hub[.]” ComEd claims that while there are well established delivery hubs for energy, there are no such hubs for RECs. ComEd maintains that this section simply could not be applied to the establishment of benchmarks for RECs. However, ComEd notes that it does not oppose the IPA and Staff attempting to evaluate contracts as the IPA proposes, with Commission approval. (ComEd Reply to Responses at 2-3)

Wind for Illinois (“WFI”) also circulated, but has not yet formally filed, a reply to the IPA’s response. It is noted that WFI did not file objections to the plan, or responses to objections. On the issue of benchmarks, the opportunity to file replies to responses was limited to the following argument appearing on page 8 of IPA’s response to objections: “… Section 16-111.5(e)(3) of the PUA states specifically that all contracts for the products procured through the procurement process, including renewable energy, shall be evaluated according to benchmarks established by the Procurement Administrator, in consult with the Commission, Agency Staff, and the Procurement Monitor.”

In its Reply to the IPA's Response to Objections, WFI takes no position on the question of whether the PUA gives the IPA the statutory authority to establish benchmarks for prices of RECs.

Nevertheless, WFI offers comments, to which no other parties had an opportunity to respond, cautioning the Commission that if REC benchmarks are not designed to allow for adjustments that provide consideration of the economic development benefits of in-state projects, as well as accounting for the economics of developing wind and other renewable projects in Illinois, benchmarks could unintentionally hinder the objectives intended by the General Assembly. (WFI Reply to Objections at 1-3) According to WFI, the IPA should not set a uniform benchmark that compares multiple forms of renewable energy evenly, or compares projects sited in Illinois to those sited in Iowa or another state.

2. Exceptions and Replies

In its BOE, the **AG** continues to argue that the Commission should permit the Procurement Administrator to use benchmarks to screen bids for renewable energy resources. The AG states that that the General Assembly recently passed and sent to the Governor legislation which amends Section 1-75(c)(1) of the IPA Act to expressly require the use of benchmarks in connection with the procurement of renewable energy resources. The AG requests that the Commission take administrative notice of the General Assembly’s action and, in light of this development, authorize the Procurement Administrator to use benchmarks to screen bids for renewable resources during the 2009 procurement. (AG BOE at 1-2, citing Senate Bill 1987 or “SB 1987)

The AG suggests that in light of the General Assembly's action, and to recognize that existing law does not preclude the use of benchmarks, the Commission should not disturb the IPA's proposal for the Procurement Administrator to establish benchmark REC prices, and to reject bids priced above the benchmarks. (AG BOE at 3)

Among numerous other things, SB 1987 would modify Section 1-75(c)(1) of the IPA Act as follows:

> 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: at least 2% by June 1, 2008; at least 4% by June 1, 2009; at least 5% by June 1, 2010; at least 6% by June 1, 2011; at least 7% by June 1, 2012; at least 8% by June 1, 2013; at least 9% by June 1, 2014; at least 10% by June 1, 2015; and increasing by at least 1.5% each year thereafter to at least 25% by June 1, 2025. To the extent that it is available, at least 75% of the renewable energy resources used to meet these standards shall come from wind generation. For purposes of this **subsection (c)** ~~**Section**~~ "cost-effective" means that the costs of procuring renewable energy resources do not cause the limit stated in paragraph (2) of this subsection (c) to be exceeded **and do not exceed benchmarks based on market prices for renewable energy resources in the region, which shall be developed by the procurement administrator, in consultation with the Commission staff, Agency staff, and the procurement monitor and shall be subject to Commission review and approval**.

In its RBOE, **Staff** points out that SB 1987 has not been signed by the Governor and is, therefore, not currently effective. (Staff RBOE at 1-2) Staff also asserts that even if SB 1987 were to be signed into law, it would not become effective until June 1, 2009. In Staff's view, SB 1987 will, therefore, not be directly applicable to the 2009 procurement events which are scheduled to occur prior to June 1, 2009. Staff states that while SB 1987 does not require modification of the proposed order, and Staff continues to support the proposed order's analysis and conclusions on the renewable resource benchmark issue, Staff, in its RBOE, proposed alternative language that would effectively accept the use of benchmarks for renewable resources during the 2009 procurement subject to certain conditions.

The language in Staff's RBOE would accept the IPA's proposal whereby the Procurement Administrator would establish benchmark REC prices, and reject bids priced above the benchmarks, subject to the Commission's authority to reject the REC benchmarks presented for approval and direct the REC procurement to proceed without benchmarks if it is determined that adequate data is not available to create such benchmarks at the time they are presented for approval.

In its RBOE, **ComEd** also observes that SB 1987 has not been signed by the Governor and is, therefore, not currently effective. ComEd continues to oppose the use of benchmarks in the Plan currently before the Commission. (ComEd RBOE at 1)

3. Commission's Conclusions

The Plan sets forth guidelines for using benchmarks to measure whether to accept or reject Renewable Energy Credit bids. (IPA Response to Objections at 7; IPA Plan at 41)

The IPA believes that so long as market prices can be verified, the PUA requires benchmarks be used in association with the acquisition of renewable resources. Staff, the AG, and ComEd disagree, arguing that the PUA has no such requirement associated with renewable resources.

Staff also expresses concerns about the use of benchmarks related to the acquisition of renewable resources. Staff is concerned that use of benchmarks in the acquisition process could interfere with or impede the accomplishment of other statutory goals related to the acquisition of renewable resources. While both the AG and ComEd share at least some of Staff's concerns regarding potential practical problems with the use of benchmarks, ComEd does not object to the specific language in the IPA's Plan and the AG believes benchmarks should be used during the 2009 procurement of renewable resources.

Preliminarily, the Commission notes that for the 2008 procurement event, as laid out in the Commission's Orders in Docket Nos. 07-0527 and 07-0528/07-0531(Cons.), no benchmarking was undertaken with regard to renewable resources.

As indicated above, the initial question in this proceeding is whether Section 16-111.5(e)(3) of the PUA requires that benchmarking be utilized with respect to renewable resources. On this issue, the Commission agrees with Staff, ComEd and the AG that the statute, when read in its entirety, currently contains no such requirement. However, if Senate Bill 1987 is signed into law, use of benchmarks will be required in development of the procurement plan for the June 2010 to May 2011 procurement period. As explained by Staff, SB 1987 would not take effect until June 1, 2009, and thus would not require benchmarking to be used in procurement events which must occur prior to that date.

The above conclusion, however, does not mean the use of benchmarks in association with the acquisition of renewable resources is prohibited by the statute -- it is not. Thus, the relevant question in this proceeding is whether the IPA should be permitted to use benchmarks in association with the acquisition of renewable resources.

On this difficult question there is no agreement. While the use of benchmarks offers potential benefits as outlined by the IPA, the AG and others, there are drawbacks. As observed by Staff, the potential adverse effects on other renewable/REC requirements in the law remain unresolved, as do concerns about the availability of adequate market price data.

All things considered, the Commission finds that the use of benchmarks associated with the acquisition of renewable resources for the 2009 procurement event should not be required. However, the IPA and Procurement Administrator will be permitted to develop benchmarks for the 2009 procurement event, in consultation with the Commission Staff and the procurement monitor, provided that adequate market price data is available and further provided that adverse effects on other renewable requirements in the law are avoided or resolved, and to utilize such benchmarks upon receipt of prior Commission approval of them. The Commission reserves the authority to reject such benchmarks, and to direct REC procurement without them, if it is determined that adequate data is not available or for other appropriate reasons.

E. Load Forecasts and Portfolio Rebalancing

Pursuant to Section 16-111.5(d)(1) of the PUA, utilities provide a range of load forecasts to the IPA by July 15, or such other date as may be required by the Commission or the IPA. The forecasts include hourly data representing a high-load, low-load and expected load scenarios for eligible retail customers.

1. Parties' Positions

ComEd states that it issues load forecasts for internal planning purposes twice a year, once in the Spring and once in the Fall. ComEd says the load forecast that it provided to the IPA in July 2008 was based on its Spring 2008 load forecast. ComEd claims that due largely to unexpected changes in economic conditions since the Spring, but including other changes as well, ComEd's most current forecast, in aggregate, shows lower expected loads. (ComEd Objections at 5-7)

In its Objections, ComEd presents an updated load forecast, not because it objects to the Plan, but in the interest of providing full information to the IPA and the Commission. ComEd also suggests that, similar to the IPA's recommendation for future procurement events, a shorter process with some flexibility for the utilities, the IPA, Commission Staff, and procurement administrator to consider updated information and make appropriate changes in the Plan, if all parties are in agreement, would improve the procurement process.

According to ComEd, because of the unusual economic changes, the IPA and the Commission may want to consider taking this information into account in this instance. Should the Commission decide to take this data into account in these unique circumstances, ComEd claims it would not be necessary to provide a completely updated forecast, or for the IPA to rewrite its entire Plan. ComEd asserts that the Commission can simply require that the amount of standard wholesale product that the IPA has proposed to be procured be revised to reflect the numbers presented in ComEd's Objections. In its Objections, ComEd provides tables that compare the old and new forecast data. ComEd also attached to its Objections revised Tables Q-a and Q-b, as well as Attachments I and J to the Plan, which its says all reflect the updated forecast data.

In its Response to Objections, **the IPA** states that the Plan currently contemplates that there may be changes to the load forecast during the procurement period, and permits the Procurement Administrator, Procurement Monitor, the IPA and the Commission to adjust the procurement activities as necessary given the changes to the load forecast. The IPA agrees that using the most recent information would be useful for this and future Plans. To address this issue, the IPA agrees that ComEd's revised forecast should be incorporated into the Plan. The IPA recommends that ComEd's revised Tables Q-a and Q-b, as well as Attachments I and J, be incorporated into the Plan, and that the Plan be modified accordingly. (IPA Response to Objections at 4)

On page 3 of its Response to Objections, the IPA also states that ComEd has no objection to the IPA's Plan in regard to portfolio rebalancing, and provides no redline changes or recommended alternatives. As a result, the IPA recommends that no modifications be made to the Plan as it believes they are not necessary in order to address ComEd's comments.

On page 14 of its Response to Objections, **Staff** expresses concern that if ComEd's revised forecast is not relied upon for setting procurement quantities, then the hedge ratios actually achieved may deviate from those recommended in the plan. In that response, and on pages 4-5 of Staff's Reply to the IPA's Response to Objections, Staff "recommends that the Commission direct ComEd to provide the Procurement Administrator any updated forecasts that are or become available, and allow the Procurement Administrator to adjust the amounts procured with the concurrence of Staff, ComEd and the Procurement Monitor, rather than accept and incorporate the revised forecast at this time without further review."

Staff also raises a concern of whether AIU or the IPA has produced a similar revision of AIU's loads, because Staff thinks that AIU may be as likely to be affected by the economic downturn as ComEd. If a similar revised forecast is not relied upon for setting procurement quantities for AIU, Staff expresses concern that the hedge ratios actually achieved may deviate from those recommended in the plan. Staff recommends that the Commission direct AIU to provide the Procurement Administrator any updated forecasts that are available, and allow the Procurement Administrator to adjust the amounts procured with the concurrence of Staff, AIU and the Procurement Monitor. (Staff Response to Objections at 7-8)

In its Response to Objections, Staff also states that it takes no position on whether two official forecasts per year is an appropriate schedule for purposes of procurement planning.

In its Reply to Staff's Response to Objections, **ComEd** insists that the Commission should approve the Plan as modified, and not order ComEd to provide available updated forecast data, so that the Procurement Administrator may adjust the forecast, even after Commission approval, with the concurrence of Staff, ComEd, and the Procurement Monitor. ComEd believes Staff's recommendation is unnecessary and unlawful. (ComEd Reply to Responses at 1-2)

According to ComEd, Section 16.111.5(d)(3) of the PUA requires the Commission to enter an Order confirming or modifying the Plan, including its load forecast, on a specified schedule. ComEd indicates that the statute requires that “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.” 220 ILCS 5/16-111.5(d)(4). ComEd states that deviations from forecast loads are inevitable and, up until the last day of the Plan’s implementation, there could always be a “newer” forecast. ComEd maintains that these inevitable changes are to be addressed in the Plan itself, as the proposed Plan does, not through post-approval modifications.

According to ComEd, if the Plan is to form a foundation for Commission-approved procurement, it should not be able to be modified by parties without Commission approval. In this case, ComEd says the original forecast was proper and the updated forecast data – which ComEd was not required to provide – is accepted by the IPA as a beneficial adjustment to the Plan. In ComEd's view, the Commission should, therefore, approve the Plan and forecast, including the updated forecast data, and not allow subsequent modifications to it by agreement of the parties.

ComEd states that in the event its annual forecast increases above the High Forecast or decreases below the Low Forecast, the IPA plans to convene the relevant parties to determine whether and how to rebalance the portfolio. ComEd indicates that it does not issue annual forecasts on an ongoing or even monthly or quarterly basis. ComEd says it issues an official forecast only twice a year: once in the Spring and once in the Fall. If either of those forecasts rises above the High Forecast or decreases below the Low Forecast, ComEd says it has no objection to taking the action outlined by the IPA.

In its Reply to Responses, the **Ameren Illinois Utilities** state that they have not and have no immediate plans to prepare an update to the hourly load forecast that was previously submitted to the IPA. AIU indicates that it has recently revised the monthly energy forecast that is one component that drives the hourly load forecast. In doing so, AIU claims to have found that on average the economic downturn has resulted in a reduction in the monthly energy forecast of approximately 1.0% to 1.5%, depending on the rate class. AIU says this forecast includes monthly energy values only and does not include a revised hourly forecast or a revised peak demand forecast. (AIU Reply to Responses at 1-3)

AIU alleges that it would be a substantial undertaking to revise the hourly forecast that was included in the procurement plan. AIU believes the benefit of such an undertaking is questionable, particularly when considering the relatively small quantity of the change. AIU states that the 1% to 1.5% downward energy revision is less than the typical Mean Expected Forecasting Error of approximately 3%. According to AIU, the 1% to 1.5% change is also smaller than the error created by rounding the actual purchase quantities to the nearest 50 MW which for the first planning year of the plan are in the plus or minus 2.5 % range in the On-Peak periods and minus 3% to plus 6% range in the Off-Peak periods.

AIU also suggests that updating the forecast in the procurement planning period, where a different procurement strategy might be considered or implemented, could be contrary to the law. AIU states that Section 16-111.5(d)(4) of the PUA, provides that when the Commission approves the procurement plan, such approval incorporates "expressly the forecast used in the procurement plan . . . ." In AIU's view, it would seem that when the Commission approves the procurement plan, and expressly approves the forecast used in the procurement plan, there is no other meaningful opportunity for the Commission or any other party to revisit the forecast until the start of the next procurement planning cycle.

AIU contends that based on the relatively small change in the monthly forecast relative to the other potential errors embedded in the forecast and procurement planning process, and AIU's view that the forecast must be expressly approved as part of the approval of the procurement plan, Staff's recommendation should be rejected by the Commission. However, if the Commission is concerned that not updating AIU's hourly load forecast places undue market risk on the end use customers of AIU, AIU suggests that a more efficient solution would be to simply reduce the Residual Volumes included in tables I-a and I-b of the IPA Procurement Plan by 1% and then recalculating the 2009 IPA Procurement quantities.

2. Exceptions and Replies

In its BOE, **ComEd** observes that the proposed order accepts the IPA's proposal for modifying its portfolio for ComEd and AIU in the event of a "significant shift" in load, as laid out in the October 21, 2008 Plan. ComEd expresses concern that the Order should make clear that if any such portfolio modifications occur, they must either: (1) occur under the rebalancing mechanisms included in the Plan itself as approved by the Commission; or (2) be submitted for approval by the Commission. According to ComEd, the PUA requires that the Commission review and approve the Plan and parties may not unilaterally modify it. To address this concern, ComEd proposes that if the IPA, after consulting the Procurement Administrator, Staff, the Procurement Monitor, and either ComEd or AIU, determines that the portfolio must be modified in a manner other than allowed under the specifically approved Portfolio Rebalancing procedures, the revised forecast and proposed revisions should be submitted to the Commission for review, investigation, and approval. (ComEd BOE at 2-3)

The Commission notes that with regard to portfolio rebalancing in the event of significant shifts in load, the IPA's Plan provides as follows:

> The PUA requires that the IPA provide the criteria for portfolio rebalancing in the event of significant shifts in load. 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 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.
> (IPA Plan at 39; see also IPA Plan at 52)

In its RBOE, **Staff** indicates that it does not disagree with certain statements made in ComEd's BOE; however, Staff expressed concern that ComEd's proposed language could cause some confusion about whether any rebalancing is allowed without Commission approval. Staff offers alternative language in its RBOE. Under Staff's RBOE language, if a "significant shift" in load occurs as described in the October 21, 2008 Plan, a rebalancing is authorized, without further Commission approval, if the IPA, the Procurement Administrator, Commission Staff, and either ComEd or AIU, as applicable, all concur to the need, extent and manner of achieving a proposed rebalancing. Also, under the Staff proposal, if the portfolio requires modification in a manner other than as allowed under Staff's interpretation of the Portfolio Rebalancing procedures in the Plan, the revised forecast and proposed revisions would be submitted to the Commission for review, investigation, and approval.

3. Commission's Conclusions

Section 16-111.5(b) of the PUA states in part:

> 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.

Additionally, Section 16-111.5(b)(4) of the PUA states:

> 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. (emphasis added)

Finally, Section 16-111.5(d)(4) states:

> 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.

As the Commission understands the statutory scheme, in this proceeding load forecasts are approved for ComEd and AIU. Based upon the approved load forecasts, the IPA undertakes procurement activities and develops a portfolio consistent with the requirements of Illinois law. The statute also requires that the approved plan include criteria to determine if there is a “significant shift in load” and a process whereby the portfolio is revised in the event of a significant shift in load.

Having reviewed the filings of the parties, the Commission finds that the load forecast for ComEd attached to the IPA's October 21, 2008 Plan (Attachment C), as modified to incorporate the update contained in ComEd's October 27, 2008 Objections and its attachments to those Objections, should be approved. The record indicates that this approved load forecast represents the best estimate of residual load requirements of ComEd for which the IPA must develop a supply portfolio. The Commission also finds that the load forecast for AIU attached to the IPA's October 21, 2008 Plan (Attachments A and B) should be approved. The record indicates that this load forecast is reasonable and the most current estimate of the residual load requirements of AIU for which the IPA must develop a supply portfolio. The Commission appreciates the comments of Staff; however, the statute requires that the Commission approve a load forecast for ComEd and AIU in this Order.

The IPA's proposal for modifying its portfolio for ComEd and AIU in the event of a “significant shift” in load, as laid out in its October 21, 2008 Plan (See IPA Plan at 39 and 52, and Section VII.E.2 of this order immediately above), is deemed to be reasonable and is hereby approved. In order to determine whether it is necessary for the IPA to modify the portfolio in the event of a significant shift in load, however, the Commission believes it would be appropriate for ComEd and AIU to provide the IPA with updated load forecasts, in addition to the notifications required by the Plan.

Therefore, the Commission directs ComEd and AIU to provide the IPA with updated load forecasts by April 15, 2009 or such other date as may be established by the mutual agreement of the Procurement Administrator, Staff, the Procurement Monitor and either ComEd or AIU, as appropriate. Thus, upon receipt of each such notification and updated forecast, the IPA shall utilize the process described on pages 39 and 52 of the Plan. Among other things, this process calls for the IPA to "convene a meeting with [the utility], 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"; it also identifies customer switching as a significant driver of load shifting levels.

If the portfolio must be modified in a manner other than as allowed under the Portfolio Rebalancing procedures described and approved above, the revised forecast and proposed revisions should be submitted to the Commission for review and approval. A petition seeking such approval shall be filed at least 21 days prior to the date by which such approval is requested.

F. Capacity

According to **AIU**, the IPA has included several discrepancies that relate to the current and pending Resource Adequacy rules required by the MISO. AIU asserts that the IPA does not correctly reflect MISO's rules regarding capacity obligations and resource adequacy. In particular, AIU states that there is the need for capacity in an amount equal to the expected peak load plus planning reserves. AIU indicates that the minimum planning reserve for 2008 planning year is 14.3% and that there is no dispute about this fact. (AIU Objections at 1-3)

AIU insists that the planning reserve is a not a static amount, and what will be required by MISO in terms of planning reserves cannot be known with exact precision at this time. AIU claims that MISO is in the process of completing a technical analysis to determine the actual planning reserve percentage for the 2009 planning year. AIU says the results of this technical analysis are not expected to be available until sometime in early 2009. In AIU's view, failure to account for some variation in the planning reserves over the planning period could result in either too much capacity, thus potentially driving up costs to customers if excess capacity is stranded or sold at a price less than purchased, or too little capacity, thus also potentially driving up costs to customers because of MISO's proposed penalties for capacity deficiency.

AIU believes the prudent course of action would be to allow the IPA to modify the planning reserve percentage and the amount of capacity to be purchased based on the actual planning reserve percentage once it is known. AIU recommends that Section IV.C.2 ii of the Plan filed by the IPA be deleted in its entirety and replaced with language as developed by it and Staff as identified on 2-3 of the AIU Objections.

In its Response to Objections, pages 4-5, **the IPA** indicates that it agrees with AIU's recommendation that the Plan be modified as laid out in AIU's Objections.

Similarly, on page 7 of its Response to Objections, **Staff** indicates it has no objections to AIU's proposal.

The **Commission** has reviewed the filings made by the parties, and it appears that the issue is no longer contested. The Commission finds that the modifications to the Capacity portion of the IPA's proposed Plan, as set forth in AIU's Objections, are reasonable and they are hereby approved.

G. Ancillary Services

AIU believes the IPA mistakenly replaced the section titled "Ancillary Services" with language pertaining to Resource Adequacy. AIU suggests that the section should be deleted in its entirety and replaced with the language included in the IPA's initial Plan filed with the Commission on September 3, 2008. AIU also provided its proposed language on page 4 of its Objections.

On page 6 of its Response to Objections, **the IPA** indicates that AIU has identified an inadvertent error and agrees with AIU's recommendation. Similarly, in its Response to Objections, **Staff** indicates it has no objections to AIU's proposal.

The **Commission** has reviewed the filings made by the parties and it appears that the issue is no longer contested. The Commission finds that the modifications to the Ancillary Services portion of the IPA's proposed Plan, as set forth in AIU's Objections, are reasonable and they are hereby approved.

H. Contingency Procurement Plan

Generally speaking, contingency plans provide procedures for obtaining electric power and energy in the event of contingencies such as a supplier default.

According to **AIU**, the procedures related to Contingency Procurement Plans for AIU are currently set forth in Rider PER – Purchased Electricity Recovery. AIU says this rider was approved by the Commission and became effective on March 3, 2008. AIU indicates that the IPA advocates a contingency plan that is different than what was approved by the Commission as it relates to the Auction Supplier Forward Contracts and the swap agreements that were required by virtue of the 2007 Rate Relief Legislation. (AIU Objections at 4-6)

AIU asserts that Rider PER and its contingency plan requirements are appropriate for the auction products procured in 2006 for delivery January 1, 2007, as well as the swap agreements that were required by virtue of the 2007 Rate Relief Legislation. According to AIU, Rider PER makes specific provision for contingent events surrounding the 2006 auction products and 2007 swap agreements. AIU suggests that perhaps the contingency plan requirements set forth by the IPA are appropriate for the standard wholesale products to be procured in 2009-2010. AIU states that nonetheless, Rider PER also takes into account contingency provisions surrounding the IPA procurement event, making specific references to Section 16-111.5(e)(5) of the PUA.

AIU believes that having potentially conflicting contingency purchase plans included in both the IPA procurement plan and the Rider PER will, at a minimum, result in confusion should any contingency procurement plan be necessitated. AIU recommends that the Commission modify the Plan such that current Rider PER and its provisions apply to the 2006 auction products and the swap agreements. AIU suggests that it will consider whether Rider PER terms need to be modified to accommodate the initial Plan and future plan requirements as it relates to contingency planning, although AIU suggests Rider PER is currently sufficient.

According to AIU, the contingency plan section of the IPA procurement plan also appears to suggest that any default of Supplier Forward Contracts (full requirements contracts resulting from the 2006 Illinois Auction) would be remedied by replacing the defaulting contracts with a new full requirements contract. AIU states that Rider PER requires, in the instance of a default of the 2006 supplier contract, that the supply be acquired in the manner consistent with the Portfolio Re-Balancing in the Event of Significant Shifts in Load section of the procurement plan then in effect. AIU desires clarity and submits that in the event of supplier default of the 2006 contracts, that the IPA should be obligated to procure those products in the wholesale market as is contemplated by Rider PER, which refers back to Section 16-111.5(e)(5).

In AIU's view, two conflicting sets of procedures related to Contingency Procurement Plans should not be in place in Rider PER and in the Commission approved procurement plan. AIU recommends that the section titled “Contingency Procurement Plan” be deleted in its entirety and replaced with a reference to the “Contingency Obligations” section in AIU's Rider PER (Electric Service Schedule Ill.CC. No. 18).

On pages 6-7 of its Response to Objections, **the IPA** agrees with AIU that changes to the contingency procurement plan would be appropriate, and the IPA proposes language for that purpose. Similarly, in its Response to Objections, **Staff** states that unless the IPA can provide convincing arguments why the language of Rider PER is deficient or otherwise inappropriate, Staff recommends that AIU's proposed change to the plan be accepted. In its Reply to the IPA's Response to Objections, Staff indicates that it concurs with the IPA recommendation.

The **Commission** has reviewed the proposals and positions filed by the parties and it appears that the issue is no longer contested. The Commission finds that the modifications to the Contingency Procurement Plan portion of the IPA's proposed Plan, as contained on page 7 of the IPA’s Response to Objections, are reasonable and they are hereby approved.

I. Demand Response Values

According to the **IPA**, the demand response requirement in the statute is "to reduce peak demand by 0.1% over the prior year." (IPA Response to Objections at 7, citing 220 ILCS 5/12-103(c); IPA Plan at 12) The Plan states in part, on page 12:

> Because the requirement appears to be cumulative, the peak to be served will shrink by 0.1% each year, eventually becoming 1.0% lower than it would otherwise be absent the demand-response measures. However, there is a difference of opinion as to the appropriate interpretation of the statute, with ComEd asserting that the requirement is not cumulative. Ameren, however, calculates this requirement as cumulative, and other parties may have differing views.

In its Objections, page 8, **ComEd** recommends, "On page 13 [of the Plan], in the last paragraph, delete the second and third sentences as they are incorrect since ComEd and Ameren calculate the demand-response requirement in the same manner." To further clarify this, ComEd proposes that the following change also needs to be made: On page 14, in the eighth line from the top, insert "incremental" between "effective" and "reduction."

In its Response to Objections, ComEd agrees with the Staff comments, discussed below, that the only difference between ComEd and AIU on the determination of the demand response values is in the manner in which they were presented. ComEd says it presented the demand response values as incremental, while AIU presented them as cumulative.

In its Objections, pages 10-12, **Staff** asserts that contrary to the IPA's suggestion, there may not be a difference of opinion regarding the amounts by which a utility is required to reduce peak demand through demand response efforts. Instead, Staff suggests there is merely a difference in presentation by ComEd and AIU. Staff states that ComEd may be presenting its demand response value for a given year as a percentage of the previous year's forecast of usage with the previous years' accumulated effects of demand response built into the forecast, while AIU may be showing the cumulative effect of demand response relative to a baseline forecast which includes no demand response programs in any of the previous years. Staff believes this is likely given the different forecasting procedures used by ComEd and AIU.

Staff presents a table, reproduced below, intended to show the effect of this difference, where, for explanatory purposes, both the ComEd and AIU load is assumed to be equal and to remain constant over time, if there are no demand response programs placed into effect. Staff states that this hypothetical constant load is shown in the first column. Staff indicates that the actual baseline forecasts of these two utilities (assuming no load response) do not project zero growth, but does not alter the principle of Staff's illustration.

	Forecast with no Demand Response	Forecast with 0.1% Reduction from Previous Year	Incremental Reduction as Presented by ComEd	Incremental Reduction as Presented by AIU
2007	100	100.0000		
2008	100	99.9000	0.1000	0.1000
2009	100	99.8001	0.0999	0.1999
2010	100	99.7003	0.0998	0.2997
2011	100	99.6006	0.0997	0.3994
2012	100	99.5010	0.0996	0.4990

Staff states that the demand response requirement in the statute is to reduce peak demand by 0.1% over the prior year. Staff says the effect of which on a hypothetical load is shown in the second column of the table and is identical for both utilities in this simple example. According to Staff, the third and fourth columns show how ComEd and AIU, respectively, may be presenting these demand response values to the IPA. Staff says they differ in that ComEd appears to be presenting incremental reductions while AIU appears to be representing cumulative reductions.

In its Response to Objections, page 12, **the IPA** suggests that the Commission accept ComEd's proposed modifications, shown on page 8 of ComEd's Objections and identified above, intended to clarify this matter.

In its Response to Objections, **the AG** states that setting aside the question of whether ComEd and AIU disagree with each other, the Commission should confirm that the IPA has accurately characterized the statutory demand-response requirement. To eliminate any possibility of confusion on this point in the future, the AG asks that the Commission's order approving the Plan specifically confirm the IPA's clear articulation of the demand-response requirement in Section 12-103(c) of the PUA.

The **Commission** has reviewed the filings by the parties and it appears that the issue is not in dispute. As explained by ComEd and Staff, AIU and ComEd calculate the demand-response requirement in the same manner; the difference is in the manner of presentation. The Commission finds that the modifications to the Demand Response Values portion of the IPA's proposed Plan, as set forth on page 8 of ComEd's Objections and page 12 of the IPA's Response, are reasonable and they are hereby approved. As for the AG's recommendation, the Commission notes that the particular language cited by the AG has not been deleted from the Plan; the Commission finds it unnecessary to make any other findings with respect thereto.

J. Residual Demand for AIU July and August 2009 On-Peak Energy

According to **Staff**, the residual demands for AIU in the July and August 2009 On-Peak periods are incorrect. (Staff Objections at 21-22) Specifically, Staff says that in table I-a on page 33 of the Plan, several values for July and August 2009 are incorrect because they fail to take into account the 10% addition to the hedge ratio in amount of electricity that already would be hedged through the 2006 Auction contracts: “2006 Auction Volumes (MW),” “Residual Volumes (MW),” and “2009 IPA Procurement (MW).”

Staff states that as written, the IPA's proposed Plan would lead to the procurement of an additional 100 MW of July and August 2009 energy hedges for AIU, adding about 3% to the IPA’s proposed hedge ratio of 110%. In Staff’s view, this is not a significant difference, and, for practical purposes, 113% and 110% hedge ratios are indistinguishable from one another.

In its Response, page 9, **the IPA** agrees with the Staff objection. The IPA recommends that Table 1-a be modified accordingly.

Having reviewed the filings, the **Commission** agrees that Table 1-a of the Plan shall be modified in the manner shown on page 9 of the IPA’s Response to Objections.

K. Release of Information to the Public

1. Parties' Positions

Staff states that Section 16-111.5 of the PUA identifies certain information and documents as confidential. According to Staff, the market-based price benchmarks to be developed by the procurement administrator for evaluating the final prices in the contracts for each of the products that will be procured through the procurement process are required to be confidential (220 ILCS 5/16-111.5(e)(3)), and are to be “submitted to the Commission for review and approval on a confidential basis.” Similarly, Staff says the reports for each procurement event to be prepared by the procurement administrator and the procurement monitor are required to be confidential. (220 ILCS 5/16-111.5(c)(1)(ix), (c)(2)(iii)(f) and (h)) Staff indicates that Section 16-111.5(h) identifies supplier and bidding information, other than certain limited information on successful bids, as a general category of information to be provided confidential treatment. (Staff Objections at 22-23)

According to Staff, under Section 16-111.5 of the PUA, the benchmarks, the reports by the procurement administrator and procurement monitor, and supplier and bidding information (other then certain information on successful bids) are to be afforded confidential treatment. However, it appears to Staff that other information related to the procurement process or procurement events is not statutorily cloaked with confidentiality under the PUA and may be publicly disclosed. In addition, Staff says the statute requires that confidential information, such as the procurement administrator’s and the procurement monitor’s reports to the Commission, remain confidential, even following the conclusion of a procurement event. Staff indicates an exception may be made, and otherwise confidential information may be released publicly, when there is “a compelling demonstration of need.”

Staff believes it would be beneficial to specify the information to be disclosed and the timing for disclosure in the next procurement plan. Staff states that if and to the extent that such information would otherwise be subject to confidential treatment under Illinois Law, a rule, regulation or tariff authorizing its disclosure would need to be approved. Staff notes, however, that the benefits of public disclosure must be weighed and balanced against the risk that public disclosure of certain information could discourage or have a negative impact on supplier and bidder participation in the procurements.

Staff says the Plan did not specify any additional information to be disclosed beyond the statutorily mandated "names of the successful bidders and the load weighted average of the winning bid prices for each contract type and for each contract term." (Staff Objections at 24)

Nevertheless, in Staff's view, the number of megawatts awarded for each contract type and for each contract term could generally be provided to the public following each procurement event. In Staff's view, such aggregate data would not constitute "confidential" information if it does not disclose information about individual bidders or about their bids. Staff submits that the number of megawatts awarded for each contract type and for each contract term would not disclose protected individual "supplier and bidding information" if there were at least three winning bidders in the entire procurement event. It also seems unlikely to Staff that release of such information would discourage or have a negative impact on supplier and bidder participation in the procurements.

Thus, Staff recommends that the Commission order approving the Plan explicitly provide that the number of megawatts awarded for each contract type and for each contract term will be publicly disclosed after a Commission vote accepting a procurement administrator recommendation to accept certain bids for future procurement events, provided there are at least three winning bidders in the entire procurement event. Staff claims its proposal would protect commercially sensitive information since a bidder could not determine the identity of any other winning bidder of any specific product from the information provided to the public. Staff believes its proposal would provide information to the public without providing to bidders commercially sensitive information about the bids of other individual bidders.

Staff also recommends addressing an issue of granularity, as it relates to the release of quantity and average price information. As previous quoted, the PUA requires the release of the "weighted average of the winning bid prices for each contract type and for each contract term." However, it is unclear to Staff whether "each contract term" refers to the 12 on-peak and 12 off-peak basic building blocks that make up any given plan year, or if "each contract term" refers to each combination of these building blocks that are included in the procurement. For instance, in the spring 2008 energy procurement, in addition to the 12 on-peak and 12 off-peak monthly products, ComEd sought bids for 10 combination-month products. Staff states that winning quantities and average prices could have been computed for all 34 products or just the 24 basic building block products. Staff recommends that the Commission order approving the Plan explicitly provide that the winning quantities and average prices for all products, rather than just the basic building block products, will be released to the public.

To summarize, Staff recommends that the Commission order approving the Plan explicitly provide: (1) that the number of megawatts awarded for each contract type and for each contract term will be publicly disclosed after a Commission vote accepting a procurement administrator recommendation to accept certain bids for future procurement events, provided there are at least three winning bidders in the entire procurement event, and (2) that the winning quantities and average prices for all products, and not just the 24 basic building block products, will be publicly released. Staff suggests that the order approving the plan could either direct that the plan be modified in this regard, or these determinations could simply be made in the order approving the plan. (Staff Objections at 25)

On pages 10-11 of its Response to Objections, **the IPA** indicates its opposition to Staff's recommendations. According to the IPA, Staff's proposal ignores the strict terms of Section 16-111.5(h), and would create a presumption of disclosing information that is required to be maintained as confidential under Section 16-111.5(h), without any party having to demonstrate the need to have this information disclosed. The IPA asserts that even Staff, in its comments, does not demonstrate why the aggregate number of megawatts would need to be disclosed; Staff simply argues that the information would not be confidential if there are more than three successful bidders. The IPA claims Staff's recommendation is barred by the plain language of Section 16-111.5.

The IPA believes that there might be an opportunity after the bids are awarded for a party or participant to petition the Commission or the IPA to disclose the aggregate number of megawatts. The IPA suggests that then the Commission or the IPA can, at that time, determine whether a participant has demonstrated a compelling need to have the information disclosed. At that time, the IPA says it or the Commission can evaluate whether disclosure would be appropriate under the circumstances that exist at the time, rather than speculate now whether the aggregate data could inadvertently disclose confidential information. Given the foregoing, the IPA opposes Staff's recommendation and recommends that no modifications be made to the Plan at this time.

In its Reply to the IPA's Response to Objections, **Staff** disputes the IPA's assertion that the information Staff recommends for disclosure is required to be treated as confidential and cannot be disclosed absent a demonstration of need. (Staff Reply to Responses at 10-14) Staff recognizes that benchmarks, the reports by the procurement administrator and procurement monitor, and supplier and bidding information (other then certain information on successful bids) are to be afforded confidential treatment under Section 16-111.5 of the PUA. However, Staff insists that the general requirement for confidential treatment is limited to supplier and bidding information; and other information related to the procurement process or procurement events is not statutorily cloaked with confidentiality under the PUA and may be publicly disclosed. Staff claims the IPA does not specifically address this argument or otherwise explain why the data proposed to be disclosed is or should be considered supplier and bidding information.

Staff says that contrary to the IPA's suggestion, it is not arguing that the standard is whether someone would consider this information confidential. Staff claims the relevant statutory standard for confidential treatment under Section 16-111.5(h) is whether the information constitutes supplier and bidding information, and insists the information it proposes to disclose does not. Staff has proposed disclosing the number of megawatts awarded for each contract type and for each contract term. Staff maintains that in and of itself, this data does not disclose information about any particular supplier or bid and, thus, is not supplier and bidding information afforded confidential treatment under the PUA. Staff argues that its proposal to limit disclosure to events with three or more successful bidders was intended to provide additional protection against the possibility of one bidder somehow “reverse engineering” specific supplier and bidding information from the sum of all information available to that bidder – including its own successful and unsuccessful bids.

According to Staff, the IPA’s criticism of Staff’s proposal to limit disclosure to situations where there are at least three successful bidders is inconsistent with longstanding Commission precedent recognizing that disclosure of aggregate data does not violate the duty to maintain the confidentiality of specific underlying data. Staff asserts that in general, the policy reason for maintaining the confidentiality of business or commercial information is to protect the proprietary information of individual companies from disclosure to competitors. (Staff Reply at 12, citing Illinois Commerce Comm’n v. Illinois Bell Tel. Co., Docket No. 06-0027, Order at 1 (May 3, 2006) (“The policy reason for keeping [the number of lines provisioned by competitive carriers] confidential is to protect the proprietary information of individual companies from disclosure to competitors.”)

Staff claims that in this context, the Commission has previously found that the disclosure of “aggregate” data “from which specific company information can not be discerned would not conflict with this policy.” According to Staff, in the Illinois Bell case, the Attorney General noted that the public release of “aggregate data” was a practice consistent with the Commission’s telecommunications market reports to the General Assembly. Staff says the Commission has taken this same approach in monitoring competitive electric supply switching for three megawatt-and-larger customers.

It is Staff's position that the analysis and reasoning applied to “aggregate data” in the telecommunications and electric monitoring cases discussed above are equally applicable to the directive to maintain the confidentiality of “supplier and bidding information.” Staff claims the disclosure of aggregate “supplier and bidding information” from which specific supplier or bidder information can not be discerned does not conflict with or violate the requirement to maintain the confidentiality of supplier and bidding information.

Staff takes issue with the IPA's recommendation that the Commission make the determination to disclose this information after bids are awarded if a party petitions the Commission to disclose the information. Staff believes this process is improper because the information proposed for disclosure is not entitled to confidential treatment in the first instance, as explained above, and thus does not require a showing of need. Further, Staff claims the IPA fails to recognize that there is a significant benefit to making a determination now, rather than later, regarding the public disclosure of this information. According to Staff, bidders should generally know '"up front" what information will be treated as confidential and what information will be considered public. Staff believes that making a habit of after-the-fact determinations could lead potential bidders to believe that there is significant uncertainty regarding what will and will not be publicly disclosed, and could have potential negative impacts on bidder participation in this and all future procurement events.

Staff asserts that after-the-fact determinations of whether certain data is entitled to confidential treatment could also give rise to arguments that bidders had an expectation of confidential treatment for all information not specifically identified as public, potentially creating unnecessary litigation under the IPA's proposed process. Staff states that if the Commission makes a determination now in this proceeding for the specific limited information identified by Staff, such concerns and arguments would not exist for that information. Staff maintains that the information to be disclosed is not subject to confidential treatment and therefore there is no need to prevent its disclosure to the public or delay a determination of its non-confidential status.

On page 8 of its Response to Objections, **the AG** urges the Commission to adopt Staff's recommendations regarding public disclosure of bid data.

Similarly, in its Response to Objections, **ComEd** supports Staff's proposal. (ComEd Response to Objections at 2) ComEd agrees that the primary purposes of the confidentiality provisions in Section 16-111.5 of the PUA are to protect individual, competitively sensitive bidder information, as well as the integrity of the bidding process. In ComEd's view, the aggregate data that Staff requests be made public does not implicate either of these concerns.

In its Reply to the IPA's Response to Objections, ComEd maintains that it does not oppose Staff's recommendation to release anonymous aggregate data. (ComEd Reply to Responses at 3) ComEd does not believe that such aggregate data from which no individual bid information can be derived is the type of "supplier" and "bid" information that cannot be disclosed. Moreover, ComEd believes that the procurement process can be enhanced by increased transparency where, as here, the information will not increase the risk or cost of participating suppliers and, thus, customers.

2. Commission's Conclusion

Section 16-111.5(h) of the PUA states in part:

> (h) The 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. The Commission, the procurement monitor, the procurement administrator, the Illinois Power Agency, and all participants in the procurement process **shall maintain the confidentiality of all other supplier and bidding information in a manner consistent with all applicable laws, rules, regulations, and tariffs**. Confidential information, including the confidential reports submitted by the procurement administrator and procurement monitor pursuant to subsection (f) of this Section, shall not be made publicly available and shall not be discoverable by any party in any proceeding, absent a compelling demonstration of need, nor shall those reports be admissible in any proceeding other than one for law enforcement purposes. (emphasis added)

Staff recommends that the Commission order approving the Plan explicitly provide: (1) that the number of megawatts awarded for each contract type and for each contract term will be publicly disclosed after a Commission vote accepting a procurement administrator recommendation to accept certain bids for future procurement events, provided there are at least three winning bidders in the entire procurement event, and (2) that the winning quantities and average prices for all products, and not just the 24 basic building block products, will be publicly released. This proposal is supported by ComEd and the AG. The IPA opposes Staff's proposal arguing that it is in violation of the statute cited above.

The Commission concurs in Staff's, ComEd's, and the AG's reading of the statute. Aggregated numbers of megawatts awarded by contract type and term do not constitute "supplier and bidder information," particularly with the restriction on public disclosure articulated by Staff. The Commission appreciates the IPA's concern but finds that its reading of the statute is simply too narrow. Additionally, the Commission agrees that by releasing or disclosing the two specific types of information identified by Staff, the procurement process will be enhanced by improved transparency where, as here, the information will not increase the risk or cost of participating suppliers and, thus, customers. In summary, Staff's recommendation on this issue is hereby approved.

L. Technical Corrections Proposed by ComEd

On page 8 of its Objections, **ComEd** states that the Plan contains several inadvertent errors and inaccuracies that should be corrected and provides specific proposed changes to the Plan.

In its Response to Objections, **the IPA** indicates that it agrees with ComEd's suggested corrections. Similarly, in its Response to Objections, **Staff** indicates it has no objections to the proposed changes at page 8 of ComEd's Objections.

The **Commission** has reviewed the filings by the parties regarding ComEd's numerous "technical corrections" to the IPA's Plan. The **Commission** finds that the modifications to the IPA's Plan contained on page 8 of ComEd's Objections, and page 12 of the IPA's Response, are reasonable and they are hereby approved.

VIII. FINDINGS AND ORDERING PARAGRAPHS

The Commission, having reviewed the entire record, is of the opinion and finds that:

(1) Commonwealth Edison Company, Central Illinois Light Company d/b/a AmerenCILCO, Central Illinois Public Service Company d/b/a AmerenCIPS, and Illinois Power Company d/b/a AmerenIP 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 Public Utilities Act and an "electric utility" as defined in Section 16-102 of the Public Utilities Act;

(2) the Commission has jurisdiction of 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) subject to the modifications explicitly adopted in the prefatory portion of this order, including recommendations and objections approved above, the Plan filed by the Illinois Power Agency 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.

IT IS THEREFORE ORDERED by the Illinois Commerce Commission that subject to the modifications, recommendations and objections 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 PUA is hereby approved.

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 7th day of January, 2009.

(SIGNED) CHARLES E. BOX

Chairman