STATE OF ILLINOIS

ILLINOIS COMMERCE COMMISSION

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

<u>ORDER</u>

DATED: December 21, 2010

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By the Commission:

I. BACKGROUND

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

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

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

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

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

II. PROCEDURAL HISTORY

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

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

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

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

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

III. OVERVIEW OF THE IPA'S PROPOSED PROCUREMENT PLAN

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

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

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

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

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

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

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

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

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

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

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

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

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

The IPA points out that Section 16-113 of the PUA provides for generation services to be declared competitive for classes of customers when the Commission finds sufficient evidence of competition to meet legal standards and that certain classes have been declared competitive as a matter of law under Section 16-113. The IPA states that all ComEd commercial and industrial customer classes with demand greater than 100 kilowatts ("kW") are deemed competitive, as are AIC customers with demand of at least 400 kW. According to the IPA, the statute allows ComEd customers with demand below 400 kW, and AIC customers with demand between 400 kW and 1 megawatt ("MW"), to continue to purchase power and energy from the utility through May 31, 2010, provided that no customer in a class that has been declared competitive is allowed to return to bundled utility service after having switched to an alternative provider. The IPA states that after that date, ComEd and AIC will procure power for a customer in a class deemed competitive only by purchasing electricity in the hourly spot market and passing through those variable market prices to the competitively declared customers that choose not to select supply service from an alternative retail electric supplier ("ARES").

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

IV. LOAD FORECASTS

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

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

A. ComEd's Load Forecast

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

Section 8-103(c) of the PUA establishes specific requirements for utility company demand response programs. Section 16-111.5(b) of the PUA requires that the Plan shall include an analysis of the impact of demand side initiatives established by Section 8-103(c). The IPA states that those demand side initiatives include the impact of demand response programs (both current and projected) and the impact of energy efficiency programs (both current and projected).

For the purpose of projecting loads for this year’s Plan, the IPA assumes that each utility intends to implement demand response programs sufficient to achieve their targeted peak reductions. Based on ComEd’s analysis, the IPA says the effective aggregated reduction in ComEd’s maximum system load requirements for eligible retail customers due to demand response programs is projected to be 42.0 MW in 2011, 53.1 MW in 2012, 63.6 MW in 2013, 74.2 MW in 2014, and 85.0 MW in 2015. Section 8-103(b) of the PUA also establishes specific requirements for energy efficiency programs that reduce energy consumption of delivery services customers by 0.2% in the 2008 planning year and by an additional 0.2% each year through 2012, growing to a total decrease in energy consumption of 2.0% in 2015 and thereafter. The IPA indicates that the annual aggregate reductions in ComEd’s supply requirements to be acquired through the RFP process (net of customer switching) is projected to be: 599.8 gigawatt-hours ("GWh") in 2011, 931.1 GWh in 2012, 1,307.7 GWh in 2013, and 1,683.9 GWh in 2014, and 2,059.9 GWh in 2015. The IPA anticipates requesting validation of the ability to dispatch the demand response assets included in the forecast in the near future. The IPA also notes that these energy efficiency values are effectively treated as all other legacy supply contracts within the Supply Resources projections for ComEd (as well as AIC).

B. AIC's Load Forecast

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

The IPA says comparisons between predicted and actual consumption volumes are highly correlated and are the best models available for forecasting loads for the eligible retail customers. Forecasted portfolio volumes are generated by altering model variables within expected ranges and examining model outputs. Resulting High, Expected, and Low volume scenarios are generated. The IPA selected the Expected Load Model as the basis of the Plan for the AIC portfolio.

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

V. PORTFOLIO DESIGN

Citing Section 16-111.5(d)(4) of the Act, the IPA contends its priorities for the portfolio design are "to ensure adequate, reliable, affordable, efficient, and environmentally sustainable electric service at the lowest total cost over time, taking into account any benefits of price stability." The IPA indicates that the challenge it faces is to achieve low and stable prices in a market where prices change constantly and sometimes dramatically. In the IPA's view, the task is complicated by variables that may significantly increase or decrease portfolio requirements over the short term (such as weather) or over the longer term (such as customer migration away from the IPA portfolio). The IPA claims that designing the portfolio requires an appreciation of the variables that drive price and load fluctuation, and the extent to which those variables can affect price. For the purposes of the IPA's analysis and planning, risk is defined as any market condition that has the potential of raising or lowering prices relative to the fixed price contracts secured through the IPA process. Risk is also defined as any change in the size of the load of eligible retail customers served through the IPA portfolio.

A. Risk Assessment

According to the IPA, Section 16-111.5(b)(3)(vi) of the PUA identifies the primary categories of risk exposure to the portfolio when it requires the IPA to include in the Plan the following:

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

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

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

The IPA points out that in the Illinois electricity market, the State policy is to support electricity choice and competitive retail markets with the IPA portfolio of fixed price contracts serving as the "default" rate provider. The portfolio is exposed to load uncertainty risk due to inelasticity of demand among many portfolio participants, meaning that consumption does not diminish significantly when prices are high. The IPA observes that consumption by bundled service customers is relatively inelastic. In the IPA's view, this is due in large part to current tariff structures that do not expose customers to price variance. The IPA says inelasticity of demand represents risk insofar as portfolio participants who continue to use large volumes of electricity when prices are high (e.g., running air conditioning units during hot summer afternoons) do not carry the full direct cost of their usage. Instead, the cost of their consumption during high cost periods is averaged across the entire portfolio. The IPA states that inclusion of demand response and energy efficiency as alternative products within the procurement events could serve as effective tools in addressing price responsiveness and load shape.

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

According to the IPA, migration of eligible retail customers to ARES presents risk to the portfolio insofar as migration can cause cost spiraling under certain conditions. The IPA provides an example that assumes that a high percentage of anticipated long-term load requirements for the IPA portfolio were secured with fixed volume contracts. The IPA further assumes that market prices decreased in the future (e.g. our recent market experience in 2008-2009). Finally, the IPA assumes that migration from the IPA portfolio to an ARES was free of barriers. The IPA claims that in such a situation, higher-than-market bundled rates available through the IPA portfolio would motivate switching by those customers who could be profitably served by ARES at the relatively lower market prices. As the number of bundled service customers eroded, the IPA says those remaining on bundled rates would effectively be paying not only for the cost of their consumption, but also the costs of disposing of the volumes secured for customers who have switched to other suppliers. The IPA states that while the purchase of receivables provisions in the PUA are designed to prevent cherry-picking of customers by ARES, there is the potential that those who do migrate will be larger, more creditworthy, and responsive to marketing; leaving behind smaller, relatively poorer, and more remote consumers. For this reason, the IPA believes the laddering-in purchases over time enables the IPA to minimize risk for consumers by allowing it to adjust procurement volumes in response to changing customer needs and market conditions.

According to the IPA, contract terms related to credit requirements for the bidders and the utilities may increase direct and indirect costs due to the premiums associated with providing credit facilities that are ultimately borne by the end-use customer. The IPA maintains, however, that it is necessary to obtain such credit requirements from the bidders in order to protect end-use customers from potentially far higher costs that could be incurred in the event of a supplier default. The IPA believes collateral thresholds should remain at the levels used in the utilities' existing energy contracts unless there is consensus among the utilities, Procurement Administrator, Procurement Monitor, and Staff that a compelling reason warrants new collateral thresholds. The IPA insists that under no circumstances should implementing new collateral thresholds require retroactive changes that lower the collateral thresholds in existing contracts entered into during past or current procurement processes. The IPA recommends that contracts entered into as a result of the procurement process should be executed through one of the following methods:

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

Time frames for securing products and services, the IPA avers, present risk to the portfolio insofar as the underlying volatility in electricity markets places a premium on time. The IPA states that compliance with the PUA leads to procurement events that occur as many as nine months after load projections are made and eight months after the Plan is developed. According to the IPA, changes in load due to retail switching and other factors, and changes in market conditions during that extended period could limit the value of the forecasts and expose customers to unnecessary risk. The IPA notes that in the most recent procurement process, revised load projections from ComEd and AIC were submitted in response to downward projections in load requirements due to economic weakness within the region.

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

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

The IPA asserts that weather patterns present risk to the portfolio because weather-related changes in demand and supply correlate with spot prices. Particular risks, the IPA states, include the possibility of having to sell electricity contracted for at relatively high fixed prices at a time of low spot market prices, or in the opposite case, having to purchase extra volumes at high spot prices. The IPA avers that electricity consumption is highly correlated to weather (e.g. hot summer temperatures drive up summer cooling load). If mild summer weather were to reduce regional cooling loads, the IPA indicates spot prices for electricity would drop. With mild weather effectively reducing demand for electricity, consumption would drop below projections based on average temperatures. The IPA suggests that excess energy procured through block contracts would have to be sold back into the market, likely at a price lower than what was originally paid and the resulting financial losses would be applied against the portfolio.

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

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

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

The IPA contends that it is limited in its ability to mitigate these growing risks outside of factoring them into cost modeling over the longer range horizon and seeking offsetting cost avoidance elsewhere within the portfolio. The IPA observes, however, that transmission cost allocation is a subject of federal regulation and any changes in transmission costs will likely be borne by all customers regardless of supplier. The IPA also states that market conditions generally relate to the drivers of market prices, customer usage, and customer switching levels. The IPA claims that these variables are included in the statistical modeling it conducted relative to the portfolio design. The IPA believes its analysis provides a reasonable representation of the significant risks associated with the June 2011 – May 2016 horizon, and that its Plan provides reasonable protection for customers from likely risk factors. As a result, given the guidance provided under the PUA, the IPA does not offer an alternative to its recommended portfolio.

B. Modeling Approach

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

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

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

Next, the IPA discusses the premises upon which it constructed its portfolio and risk management approach, beginning with physical and financial product parity. According to the IPA, a physical product is one in which the contract requires furnishing of a specified volume of electricity under the terms and conditions of the contract. A financial product, the IPA says, is an agreement to guarantee the price for a specified volume of electricity. The IPA views prices for physical electricity products to be equivalent to financially based electricity products, insofar as suppliers of physical products price offers based on forward price curves determined in futures markets.

The IPA views existing forward markets as providing sufficient liquidity to assure price competition for up to three years. The IPA believes that trading volume in the periods greater than three years into the future are presently insufficient to assure that observed prices are available, reliable, and representative. According to the IPA, past market performance with regard to price volatility, trending, and correlations is the basis of the assumptions incorporated into IPA modeling and evaluations. The IPA indicates that it used three metrics to identify price risk:

- Metric A: Year-over-Year Price Variance – the extent to which prices change from one year to the next,
- Metric B: Mark-to-Market Price Variance – the extent to which prices agreed to in prior years vary from index prices in the current market, and
- Metric C: Longitudinal Variance – the extent to which prices in the latter years of a plan vary from current futures market prices.

To establish a model portfolio for ComEd and AIC, the IPA indicates that a Monte Carlo[2] model using Excel and Crystal Ball software was developed and applied to each utility's respective load projections to illustrate the trade-offs between risks and benefits associated with different procurement approaches and ratios of Forward and Index purchases. The IPA asserts that with efficient market prices, all portfolios should have the same expected value; however, price stability (measured as standard deviation) can vary. The IPA says that to evaluate the price stability of the different portfolios, volatility in the three price metrics was measured and combined to generate a composite risk metric for use in the evaluation. The composite metric that the IPA created is the square root of the average (A) Year-over-Year Price Variance, (B) Mark-to-Market Price Variance, and (C) Longitudinal Variance.

The IPA states that a set of potential portfolios was evaluated with multiple model runs against the risk metric defined above. The IPA says there are three main sections to the model, the first of which is the price section. According to the IPA, the model uses monthly forward peak and off-peak New York Mercantile Exchange ("NYMEX") pricing through 2016 as of August 10, 2010. The IPA views NYMEX as an appropriate indicator of future prices in the nearer term where market liquidity is sufficient to generate pricing competition. The IPA says that for periods after 2013, the monthly prices indicated on the NYMEX for those periods were escalated at 2% per year to account for market unknowns.

To test how each portfolio will perform under various market conditions, the IPA indicates that the forward price curves are assumed to vary over time. Prices for forward energy products are highly volatile, meaning that the price observed today for a product may be quite different than the price of that same product when observed at some point in the future. These volatilities, the IPA states, include changes in prices due to all factors, including fuel price movements. The IPA says market price volatility was selected as the appropriate representative of market price risk because the utilities do not own generation and therefore can not control variables such as fuel expense.

According to the IPA, price movements in delivery periods beyond the first year of the forward curve were modeled to move proportionately to movements of the first year, but with somewhat lower volatility. The magnitude of these proportional movements, the IPA says, is based on an historical analysis of how prices in years 2-6 of the forward curve moved relative to the magnitude in movements in the price of the

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

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

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

The second main section of the model relates to estimated load requirements. The IPA avers that as market prices are uncertain and will deviate from estimates, so too will the actual supply required by eligible customers deviate from even the best forecast. To capture this risk, the IPA indicates that the model starts with the base load estimates for eligible retail customers supplied by ComEd and AIC on July 15, 2011 and then allows the Monte Carlo simulation to vary the loads based on both weather and non-weather (economy and retail switching) factors. The IPA says the model assumes a triangular distribution for the loads based on the high/low load forecasts supplied by ComEd and AIC.

According to the IPA, for each month for both peak and non-peak (wrap) periods, the model takes the included load for the scenario and estimates the net open requirements by subtracting (1) the load previously awarded through the auction process (2) from the amount hedged through the swap arrangements. In addition, the IPA says the model does factor for intentional oversubscription of planned volumes in summer months (July and August) and non-summer periods to investigate whether procuring more or less than 100% of net open requirements would reduce a model portfolio's risk.

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

According to the IPA, a key factor in the analysis is the cost associated with the load shape that results from customers using relatively more energy when prices are high and relatively less energy when prices are low. The IPA says this relationship between expected prices and expected demand generally has the effect of raising the cost to serve load above the level of the straight average price during a delivery period.

Since the procurement Plan is using monthly block products that provide the same amount of energy every hour (i.e. not sculpted to match expected customer demand), the cost difference between supply provided by these block products and actual customer load profile is picked up through a price/load gross-up factor.

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

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

C. Proposed Portfolio Design

The IPA claims that the model was designed to help identify whether some portfolios may be superior to others when looking at specific risk metrics. For conceptual ease, the IPA separated portfolio characteristics into two categories: 1) the composition of the portfolio (i.e. what mix of products) and 2) the scale of the procurement (i.e. the volume purchased relative to the expected future load requirement). The IPA explains that several portfolio structures were tested in the model to help identify whether one was of relatively lower risk than the others when evaluated using the composite risk metric. The portfolio structures analyzed by the IPA ranged from all requirements being purchased in the RFP just prior to the beginning of the delivery period to all requirements being purchased three years in advance (the extent of assumed market price liquidity). The IPA says each of these portfolios was scaled to provide 100% of the expected load requirement so that scale effects could be disassociated from composition effects.

For the portfolio structure analysis, the IPA indicates it focused on the 2013-2014 period. The IPA says it chose to look out this far to get past legacy contracts including the swaps which tend to distort near-term results in an attempt to illustrate the level of risk each portfolio would produce in a "Steady State." According to the IPA, the lowest price risk scenario is achieved when the portfolio is procured relatively evenly over three years, the current period for which there is sufficient liquidity in wholesale energy markets. The IPA states that procurement distributions ranging between 20% and 40% per procurement cycle were determined to be relatively comparable in their capacity to mitigate risk. Because future market conditions are unknown, the IPA proposes to employ a portfolio distribution schedule that allows between 20% and 40% of projected loads to be procured in each of the three years prior to the delivery month.

Within this range, the IPA asserts that acquiring 35% of projected energy needs procured two years in advance of the year of delivery; 35% of projected energy needs procured one year in advance of delivery; and 30% of projected energy needs procured in the year in which power is to be delivered would yield the lowest and most stable prices, based on current market conditions. In the IPA's view, such a laddered procurement strategy provides a reasonable hedge while allowing sufficient flexibility in future procurement cycles to incorporate longer-term contracts for certain products should the planning process find that they are appropriate elements of the portfolio. The IPA suggests this 35/35/30 model portfolio is analogous to dollar cost averaging in investing. The IPA notes that this laddering of energy supply contracts does not apply to the purchase of RECs.

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

In the IPA's view, it is important to remember that quantitative analysis is a modeling exercise based on historical patterns and assumptions about future load requirements. As such, the IPA reports the model can not predict where prices will be in the next three- to five-year period. Instead, the IPA indicates that the model provides indications on how relative price volatility is managed under different portfolio distributions, thus meeting the IPA’s charge to address price stability.

The IPA believes capturing low costs is another issue. Qualitative evaluation of the current markets indicate to the IPA that regulatory compliance may force a fair amount of coal generating assets out of the market within the next decade. Replacement capacity appears to the IPA to be planned, however, many queue applicants are renewable energy generators with little to no baseload capacity value. At this time, the IPA asserts that the market presents the probability of meeting replacement coal capacity, future load growth, and balancing variable output renewable assets with new or converted natural gas assets. While this forecast is not a certainty, the IPA believes it would be imprudent to ignore the cost impacts that such a future would hold for consumers. In this environment, the IPA recommends continued layering of future purchases ahead of the time when economic growth returns and the full impact of coal asset retirement is fully realized.

VI. APPLICATION OF PROPOSED PORTFOLIO DESIGN

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

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

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

Rate Class	Description
• DS-1	Residential
• DS-2	Non residential, less than 150 kW peak demand
• DS-3a	Non residential, between 151 kW and 400 kW peak demand
• DS-5	Lighting service
• QF	Qualified Facilities. The Company must procure energy from any qualifying facility meeting the requirements of Rider QF– Qualifying Facilities. Such qualifying purchases are considered to be preexisting purchases and shall be recovered in Accrued Expenses for the Purchased Electricity Adjustment.

A. Energy Supply Requirements

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

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

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

Given these facts, the IPA plans for the Procurement Administrator to issue solicitations to lock-in fixed prices for fixed quantities of energy supply, using single-month, multi-month, and/or annual contracts for on-peak, off-peak, and/or ATC blocks during the period between June 2011 and May 2014, in whatever combinations are deemed appropriate by the Procurement Administrator, given the objectives described in this Plan. The IPA states that the target procurement quantities are determined by multiplying ComEd's and AIC's average net load obligation (average forecasted load) in each monthly on-peak/off-peak period by the targeted hedge position after the procurement event is completed (i.e. 35% for requirements two years out, 70% for requirements one year out, and 100% for requirements in the year in which power is delivered).

Next, MWs covered by the previous RFPs and ExGen and Ameren Energy Marketing swaps are subtracted from the target requirements. To the extent the calculated procurement quantity for a period is less than zero, the IPA says no energy will be procured for that period and existing positions will be maintained. The IPA also notes that calculations in the model are rounded to the nearest 50 MW. The IPA believes that by procuring a portfolio of the most granular standard wholesale products available and in quantities reflective of forecasted loads, the forecasted net amount of energy transacted in the volatile spot market will be minimized.

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

Based on the current load forecast, the quantities of standard wholesale energy products to be procured through the sealed-bid RFP by the IPA in the current procurement cycle, rounded to the nearest 50 MW, are shown in the tables below. The IPA notes that consistent with past practice, the contract volumes in the schedule include a 10% increased purchase volume for the on-peak periods in the months of July and August. According to the IPA, this increase is included to serve as a hedge against unforeseen increases in weather-related demand during those periods.

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

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

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

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

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

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

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

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

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

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

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

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

The IPA recommends that the contracts to be procured through the RFP be settled physically for ComEd volumes. According to the IPA, physical contracts are lower risk in the event of supplier default. The IPA says exposure of a supplier under a CFD is limited only by the PJM energy price cap of $999/MWh. While it would be very rare for prices for a sustained period to be at or near the energy price cap, the IPA states that a primary value of a hedge is to protect against such occurrences. In the IPA's view, it is not inconceivable that a supplier may in fact be unable to pay the difference between spot and contract prices if there is a sustained price spike. If the contract is physical, the IPA says the supplier will be liable to PJM, and until the supplier's PJM market privileges are revoked, ComEd will receive the energy at the contract price. The IPA adds that any default costs would be spread over PJM. In the event of a default under a CFD, the IPA indicates that ComEd would owe PJM the high spot prices and would bear the cost of the supplier being unable to pay the difference. While increased collateral may reduce this risk, the IPA claims it is not clear that there are adequate credit provisions to equalize this risk; therefore the IPA believes the physical contract is of lower risk for customers.

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

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

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

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

The IPA states that upon Commission approval of the Plan, ComEd will utilize the PJM-administered day-ahead and real-time energy markets to balance its loads. On a daily basis, the IPA says ComEd will report to PJM its estimate of its total load requirements for the following day. ComEd, the IPA reports, will then submit its day-after estimate to PJM via a daily load responsibility schedule and the estimate will in turn be settled by PJM based on the real-time market prices. The IPA indicates that if the delivered physical power exceeds the day-ahead estimate, PJM will credit the difference to ComEd at the day-ahead price; if the delivered physical power is less than the day-ahead estimate, PJM will charge ComEd the difference at the day-ahead price. When ComEd submits its day-after estimate to PJM, the IPA states that PJM will perform a similar settlement function in the PJM real-time market. To the extent the day-ahead estimate reported by ComEd is less than the day-after estimate; the IPA says PJM will charge ComEd the difference at the real-time price. To the extent that the day-ahead estimate reported by ComEd is greater than the day-after estimate, the IPA says PJM will credit ComEd with the difference at the real-time price.

Upon Commission approval of the Plan, the IPA says AIC will enter into financial swap transactions to hedge the energy price risk of the portfolio. The IPA indicates that 100% of the energy required to supply the load included in the Plan will be purchased in the MISO energy markets. According to the IPA, AIC will forecast respective load requirements for each delivery day in accordance with industry standards and practices for each delivery day. These forecasts will be utilized to submit a day-ahead demand bid to the MISO market, which will be settled with the MISO at a price equal to the MISO day-ahead LMPs for each hour. The IPA indicates that hourly balancing will be performed through the MISO real-time energy market, with deviations from the day-ahead demand bid settling at a price equal to the MISO real-time LMP. The IPA states that MISO charges, including Revenue Neutrality Uplift and Revenue Sufficiency Guarantee payments will also apply.

B. Capacity Resources

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

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

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

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

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

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

C. Demand Response Resources

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

D. Renewable Energy Resources

The IPA observes that Section 1-75(c) of the Illinois Power Agency Act ("IPA Act"), 20 ILCS 3855/1-1 et seq., establishes that:

> The procurement plans shall include cost-effective renewable energy resources. A minimum percentage of each utility's total supply to serve the load of eligible retail customers, as defined in Section 16-111.5(a) of the Public Utilities Act, procured for each of the following years shall be generated from cost-effective renewable energy resources . . . .

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

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

The IPA indicates that the statute establishes a methodology for calculating annual volumetric goals for the portfolio as well as establishing a Renewable Energy Resource Budget ("RERB") that serves as a maximum cost cap for meeting those goals. The IPA also indicates that in the event that the cost cap is met, purchases of renewable energy resources in excess of existing contract amounts would be limited or curtailed, leaving the annual volumetric goal unmet. A table summarizing this information is reproduced below.

Delivery period	Minimum Percentage (Annual volume goal)	Maximum Cost Standard
2011-2012	6% of June 1, 2009 through May 31, 2010 eligible retail customer load	The greater of an additional 0.5% of the amount paid per kWh by those customers during the year ending May 31, 2010 or 2% of the amount paid per kWh by those customers during the year ending May 31, 2007
2012-2013	7% of June 1, 2010 through May 31, 2011 eligible retail customer load	No more than the greater of 2.015% of the amount paid per kWh by those customers during the year ending May 31, 2007 or the incremental amount per kWh paid for these resources in 2011
2013-2014	8% of June 1, 2011 through May 31, 2012 eligible retail customer load	No more than the greater of 2.015% of the amount paid per kWh by those customers during the year ending May 31, 2007 or the incremental amount per kWh paid for these resources in 2011
2014-2015	9% of June 1, 2012 through May 31, 2013 eligible retail customer load	No more than the greater of 2.015% of the amount paid per kWh by those customers during the year ending May 31, 2007 or the incremental amount per kWh paid for these resources in 2011
2015-2016	10% of June 1, 2013 through May 31, 2014 eligible retail customer load	No more than the greater of 2.015% of the amount paid per kWh by those customers during the year ending May 31, 2007 or the incremental amount per kWh paid for these resources in 2011

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

Renewable Portfolio Standard Metrics and Targets for 2011-2012

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

The IPA plans to direct the Procurement Administrator to continue to establish benchmark REC prices (as in the two prior Plans), and to reject bids priced above the benchmarks. The IPA states that benchmarks will be set at levels that consider relevant market prices and the economic development benefits of in-state resources. According to the IPA, the benchmark prices shall be confidential, but shall be provided to, and will be subject to, Commission review and approval prior to solicitations of REC bids. The IPA adds that Section 1-75(c)(3) of the IPA Act requires that until June 1, 2011 cost effective renewable energy resources be procured first from facilities within the State of Illinois, then from facilities located in states adjacent to Illinois, then from facilities located elsewhere. The IPA proposes that each agreement for the acquisition of a REC to have a specified term and for all RECs to be retired in compliance with Section 1-75(c)(4) of the IPA Act.

The IPA states that the acquisition of RECs in amounts equal to the statutory requirement ensures compliance with such statutes. The IPA also says that the PJM Environmental Information System's ("EIS") Generation Attribute Tracking System ("GATS"), the Midwest Renewable Energy Tracking System ("M-RETS"), and the North American Renewables Registry ("NARR") will be utilized to independently verify the location of generation, resource type, and month and year of generation. According to the IPA, GATS tracks generation attributes and the ownerships of the attributes as they are traded or used to meet RPS and other programs, typically for generators whose energy is settled in the PJM market or whose facility is located in the PJM footprint. The IPA adds that M-RETS tracks renewable energy generation and assists in verifying compliance with individual state/provincial RPS requirements or voluntary programs, for generators located in South and North Dakota, Minnesota, Wisconsin, Iowa, Illinois, and Ohio. The IPA relates that NARR tracks renewable energy generation from facilities typically outside of the M-RETS and PJM footprints.

E. Incremental Procurement Events

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

F. Transmission Service; Ancillary Services; Auction Revenue Rights

According to the IPA, in addition to the acquisition of power and energy related products, ComEd is obligated by the PJM tariff to acquire certain transmission service related products and services to effectuate delivery of power and energy to the applicable loads. The IPA explains that ancillary services are services that are necessary to support capacity and the transmission of energy from resources to loads while maintaining reliable operation of the transmission system. The IPA indicates that PJM operates an ancillary services market to provide regulation service and operating reserve service (both spinning and supplemental) reserves. ComEd, the IPA says, will secure these required services through the PJM ancillary services market. Additionally, ComEd may be allocated certain financial transmission/auction revenue rights ("ARR"). ARRs are not a power and energy resource. The IPA indicates, however, that the nomination and subsequent allocation of such rights to ComEd generally serves to reduce the cost of congestion borne by ComEd (and, thus, ultimately by its customers). As part of the 2010-11 ARR allocation process at PJM, the IPA says ComEd received a set of ARR entitlements and was awarded ARRs for that planning year.

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

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

For future planning years, the IPA recommends that AIC continue to actively participate in the MISO ARR nomination and allocation process and seek to nominate those ARRs with an expected positive value. Like ComEd, the IPA says AIC recognizes it may not be allocated all of the ARRs requested and it may be required by MISO to accept certain ARRs which do not have an expected positive value. The IPA suggests that AIC retain the allocated ARRs and receive associated credits for its customers. The IPA also believes AIC should make no further changes except to the extent that should the delivery point for one or more of the energy resources be other than within the Ameren Transmission-Illinois balancing authority, AIC may attempt to reallocate the applicable ARRs from its historical resource points to those which align more closely with the designated energy resource delivery point.

G. Portfolio Rebalancing

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

H. Contingencies

The IPA has developed a plan to procure power and energy for ComEd's eligible retail customer load should all or any part of that load not be met due to the advent of: (1) supplier default, (2) insufficient supplier participation, (3) Commission rejection of procurement results, or (4) any other cause. The IPA asserts that the proposed plan is based on the contingency plan as specified in the IPA Act and Section 16-111.5(e)(5)(i) of the Act.

In the event of a supplier default that results in contract termination where the amount of load provided by that supplier is 200 MW or greater and there are more than 60 calendar days remaining on the defaulted contract term, the IPA proposes that ComEd immediately notify it, Staff, and the Procurement Administrator that another procurement event must be administered. The IPA proposes for the Procurement Administrator to execute a procurement event to replace the same products and amounts as that initially approved by the Commission in the Plan. The IPA proposes that Staff and the Procurement Monitor oversee the event. The replacement plan will, to the maximum degree possible, seek to replace the defaulted products with the same or similar products to those that were defaulted on. Under the IPA's proposal, this substitute plan would continue to seek energy-only standard-block products. The IPA says all ancillary services, capacity, and load balancing requirements will continue to be procured through the PJM-administered markets. During the interim time period beginning at time of default and continuing through the contingency procurement process, the IPA plans for all electric power and energy to be procured by ComEd through PJM-administered markets. In the event of a supplier default that results in contract termination where the amount of load provided by that supplier is less than 200 MW or there are less than 60 calendar days remaining on the defaulted contract term, the IPA proposes that ComEd procure the required power and energy directly from the PJM administered markets. The IPA says this procurement would include day ahead and/or real-time energy, capacity, and ancillary services. Regardless of the amount in question, should a required product not be available directly through the PJM administered markets, the IPA says it shall be procured through the wholesale markets.

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

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

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

VII. DISPUTED ISSUES AND COMMISSION CONCLUSIONS

A. Energy Efficiency Measures

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

1. ComEd Position

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

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

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

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

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

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

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

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

In response to the NRDC's support for the IPA's EEAR proposal, ComEd notes that Section 16-111.5(b)(iv) of the PUA requires that the Plan include the proposed mix and selection of standard wholesale products for which contracts will be executed during the next year, separately or in combination, to meet that portion of its load requirements not met through pre-existing contracts. Consistent with these statutory requirements, ComEd also notes that Section 16-111.5(b)(v) requires the Plan to include the proposed term structures for each wholesale product type included in the proposed portfolio of products. ComEd claims that NRDC's argument that the use of standard wholesale products is not required flies in the face of the above-described specific statutory language.

2. AIC Position

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

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

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

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

3. Staff Position

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

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

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

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

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

4. NRDC Position

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

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

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

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

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

5. ELPC Position

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

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

6. IPA Position

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

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

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

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

7. AG Position

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

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

8. Commission Conclusion

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

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

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

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

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

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

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

B. Demand Response

1. ComEd Position

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

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

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

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

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

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

2. AIC Position

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

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

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

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

3. IPA Position

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

4. AG Position

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

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

5. Commission Conclusion

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

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

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

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

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

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

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

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

C. Procurement of Renewable Resources

1. Iberdrola Position

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

2. WOW Position

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

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

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

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

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

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

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

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

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

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

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

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

3. Duke Position

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

4. AIC Position

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

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

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

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

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

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

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

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

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

5. ComEd Position

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

6. ExGen Position

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

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

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

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

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

7. CECG Position

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

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

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

8. Staff Position

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

9. IPA Position

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

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

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

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

10. AG Position

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

11. RESA Position

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

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

12. ICEA Position

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

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

13. TradeWind Position

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

14. Horizon Position

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

15. IWEA Position

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

16. ELPC Position

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

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

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

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

17. Commission Conclusion

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

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

> "Renewable energy resources" includes energy and its associated renewable energy credit or renewable energy credits from wind, solar thermal energy, photovoltaic cells and panels, biodiesel, crops and untreated and unadulterated organic waste biomass, tree waste, hydropower that does not involve new construction or significant expansion of hydropower dams, and other alternative sources of environmentally preferable energy. For purposes of this Act, landfill gas produced in the State is considered a renewable energy resource. "Renewable energy resources" does not include the incineration or burning of tires, garbage, general household, institutional, and commercial waste, industrial lunchroom or office waste, landscape waste other than tree waste, railroad crossties, utility poles, or construction or demolition debris, other than untreated and unadulterated waste wood.

Section 1-10 defines RECs as:

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

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

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

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

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

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

> (c) Renewable portfolio standard.
>
> (1) The procurement plans shall include cost‑effective renewable energy resources. A minimum percentage of each utility's total supply to serve the load of eligible retail customers, as defined in Section 16‑111.5(a) of the Public Utilities Act, procured for each of the following years shall be generated from cost‑effective renewable energy resources: . . . .

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

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

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

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

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

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

D. Supplier Collateral Thresholds

1. ComEd Position

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

> Collateral Thresholds should remain at the levels used in the utilities' existing energy contracts unless there is consensus among the utilities, Procurement Administrators, Procurement Monitor and Staff that a compelling reason warrants new Collateral Thresholds. Under no circumstances should implementing new Collateral Thresholds require retroactive changes that lower the Collateral Thresholds in existing contracts entered into during past or current procurement processes. (Plan at 16)

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

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

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

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

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

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

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

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

2. Staff Position

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

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

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

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

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

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

Staff notes that ComEd also proposes to strike out the sentence on contract terms that states, “[u]nder no circumstances should implementing new Collateral Thresholds require retroactive changes that lower the Collateral Thresholds in existing contracts entered into during past or current procurement processes.” Staff complains that ComEd does not provide a rationale for that deletion. In Staff’s judgment, omitting that language would be unwise given such actions would undoubtedly increase risk to suppliers because suppliers could not rely on the credit terms of the contracts they sign. An increase in supplier risk would lead to an increase in contract prices. Therefore, Staff urges the Commission to reject ComEd’s recommendation to delete the sentence that prohibits making retroactive changes to existing contracts. If, however, the Commission finds merit in ComEd's arguments, Staff recommends that at a minimum the Plan retain the language prohibiting retroactive changes to existing contracts. In Staff’s view, the language prohibiting retroactive changes would eliminate a potential risk factor that could prove very costly to customers.

3. IPA Position

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

4. Commission Conclusion

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

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

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

E. Short-Term REC Collateral Requirements

1. ComEd Position

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

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

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

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

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

ComEd notes that the conclusion that no collateral requirements need be imposed on one year REC contracts is wholly premised on ComEd's understanding that, under the IPA Act, replacement RECs are not required to be procured. If the Commission determines that replacement RECs are required to be procured, then adequate collateral should be required to be posted by the suppliers in order to protect customers.

In its reply to the various responses to the comments, ComEd states that WOW, Staff, and the IPA appear to be willing to discuss this issue further. ComEd agrees that this issue is best left to further discussion among the parties. In order for the parties to discuss this further, however, ComEd asserts that the language in the Plan that seeks Commission approval for specific collateral requirements for short-term RECs needs to be deleted. Otherwise, ComEd reasons, the issue will have been decided and there will be nothing left for the parties to discuss. In addition, in order to enable the parties to properly address the amount of collateral for RECs for the 2011 REC procurement event, ComEd states that the parties need a Commission determination in this docket as to whether or not the procurement of replacement RECs is legally required in the event of a supplier default. Therefore, in its order, ComEd contends that the Commission should explicitly state that the language in the Plan describing the amount of collateral for RECs should be deleted because replacement RECs are not required to be procured and that, during the implementation phase of this procurement, the parties should discuss the appropriate amount of collateral to require in light of that decision.

ComEd notes further in its reply that WOW disagrees with ComEd's proposal that suppliers who default on REC contracts not be allowed by the IPA to participate in future REC procurements. WOW argues that this amounts to a penalty that is unenforceable under Illinois law. ComEd agrees that penalties in contracts may be unenforceable in Illinois. ComEd states, however, that it is not proposing this as a contract remedy. ComEd is recommending that the Commission and the IPA adopt this proposal as a part of their statutory responsibility to design, oversee, and implement a procurement process in Illinois and to establish the criteria and qualifications for bidder participation. Nevertheless, ComEd states that it is willing to discuss the appropriate remedy for supplier defaults on RECs along with other contract terms in the procurement implementation process led by the Procurement Administrator.

2. WOW Position

WOW contends that collateral is not needed for one-year RECs, but for reasons different from those of ComEd. Consequently, WOW reaches a different proposal for ensuring that Illinois utilities actually receive RECs. WOW expects one-year REC prices to be considerably lower in the 2011-2012 procurement than those awarded last year because the pool of potential bidders is expanding to include adjacent state resources as well as in-state resources (see Section 1-75(c)(3)) of the IPA Act). WOW states that average prices last year were in the range of $4 to $5 per REC. WOW claims that the administrative burden of the paperwork associated with collateral and the line of credit usually outweighs the benefit from a product of very low dollar amounts. In addition, WOW suggests that there would be administrative benefits to both sides if the collateral were replaced with something both could agree upon.

WOW understands ComEd's concern to be that given the low prices Illinois utilities will be paying for RECs next year, suppliers may have an incentive to incur the contract damages and sell RECs for a higher price elsewhere. WOW asserts that there is always risk that a contract will not be fulfilled, which is why Illinois courts allow parties to minimize their risk by including liquidated damages or collateral and federal courts have acknowledged the existence of efficient breaches. Regardless of the method used within the contract, WOW claims that the purpose of damages is to encourage/secure performance in a fair and reasonable manner in light of the anticipated or actual loss. ComEd's recommendation to bar a defaulting supplier from participating in future procurements is too extreme, in WOW's opinion; and amounts to a penalty (the death penalty for a supplier in Illinois) rather than a requirement that the REC purchaser be made whole.

Furthermore, WOW argues that ComEd's recommended penalty is unconscionable and unenforceable as a matter of public policy. WOW states that penalty provisions are generally frowned upon and Illinois courts have found them unenforceable. (WOW response to objections at 4-5 citing American Nat. Bank & Trust Co. of Chicago v. Regional Transp. Authority, 125 F.3d 420, 439-40 (7th Cir. 1997) (finding that damages for breach by either party may be liquidated in the agreement but only at an amount that is reasonable in the light of the anticipated or actual loss caused by the breach and the difficulties of proof of loss; a term fixing unreasonably large liquidated damages is unenforceable on grounds of public policy as a penalty.) and Lake River Corp. v. Carborundum Co., 769 F.2d 1284, 1290 (7th Cir. 1985)) WOW suggests the best course of action is to allow the parties to discuss or negotiate a provision that would discourage breach of contract.

WOW therefore recommends that the Commission order the parties to discuss and agree upon mutually acceptable terms which would discourage them from defaulting on the contract. WOW relates that Section 16-111.5(e)(2) of the PUA provides the guidelines and identifies the participants for developing a standard contract form that follows the procurement plan approved by the Commission and meets generally accepted industry practices. Although not supportive of an effort by the Commission to decide contract terms in this context, if the Commission wishes to address this issue at this time, WOW offers an alternative. In the event of a default by the supplier of the RECs, WOW suggests that the supplier pay the utility the higher of (1) the value of that supplier's contracted REC or (2) the load weighted average winning REC price as posted by the Commission pursuant to Section 16-111.5(h), multiplied by the number of RECs that were the subject of the default. WOW asserts that this would be a fair and reasonable damages provision given its relationship to the actual costs incurred by the utility.

WOW also observes that ComEd interprets its responsibilities as not including any obligation to procure replacement RECs following a default. WOW believes this interpretation of the RPS runs headlong into it not being able to enforce a liquidated damages provision, and not being able to comply with the intent of the statute -- that RECs actually be purchased and possession taken by the Illinois utility. WOW suggests that a liquidated damages provision provides certainty and is not uncommon. WOW also believes that its proposal should address ComEd's concern of reducing a supplier's interest in selling RECs to other buyers and give money to the utility so it can purchase replacement RECs.

3. AIC Position

AIC recognizes that default by an energy supplier is a serious matter and that the utilities and their customers need to be protected from the potential for a repeat offense. Nevertheless, AIC contends that a life time ban appears to be extreme. AIC therefore suggests a solution whereby defaulting suppliers would not be allowed to participate in the procurement process for a period of two to three years following the offense.

4. Staff Position

Staff states that while it is true that nothing in the IPA Act requires replacement RECs, it is also true that nothing in the IPA Act prohibits replacement RECs. Regardless, Staff believes ComEd's proposal brings to light an important omission in the IPA Plan. Staff indicates that the IPA Plan does not specify what will occur in the event of a supplier default under short-term REC contracts. Therefore, Staff recommends that the Plan specify a contingency plan in the event there is a supplier default under a short-term REC contract.

Staff suggests that ComEd's proposal may be more appropriate than Staff's recommendation that ComEd REC contracts include the same collateral requirements as AIC REC contracts if the IPA Plan specifies that, following a REC supplier default, utilities are not required to purchase any replacement RECs or utilities are required to purchase replacement RECs in an amount that equals the remaining contract value for the defaulting REC supplier. In contrast, if the IPA Plan requires the utilities either to purchase replacement RECs using collateral on hand or to replace all RECs that were not provided due to a supplier default, then Staff believes its proposal would be more appropriate than ComEd's proposal. In Staff's view, the decision regarding contingency plans in the event of a REC supplier default involves a trade off between lower contract prices for RECs due to eliminating collateral requirements for REC suppliers and lower REC replacement costs should a REC supplier default. Staff recommends the IPA evaluate the costs and benefits associated with the possible outcomes of this tradeoff and provide a contingency plan for the Commission to approve or modify in the Plan.

Staff does not support WOW's primary recommendation that the Commission order the parties to discuss and agree upon mutually acceptable terms to discourage parties from defaulting on a contract. WOW's alternative proposal for substituting collateral requirements with a liquidated damages provision, however, intrigues Staff because it could potentially balance the risk allocation between the utilities and REC suppliers in a manner that minimizes costs incurred by customers. Staff therefore recommends that the Plan be modified to allow stakeholders the opportunity to vet WOW's alternative proposal for liquidated damages as well as other credit requirement proposals that may minimize costs ultimately incurred by customers relating to the utilities' one-year REC contracts. Furthermore, in recognition of the IPA's goal of harmonizing the utilities' one-year REC contracts, Staff states that any alternative credit requirements should be acceptable to both utilities in order to unify the credit requirements for one-year REC contracts to the maximum extent possible. Specifically, Staff recommends adding to page 4 of the Plan, ". . . unless an alternative proposal is acceptable to the procurement administrators, the utilities, the IPA, Commission Staff and the procurement monitor." Even if the Procurement Administrator can not agree on an alternative approach to credit requirements, Staff maintains that this language would require uniform collateral requirements for the utilities that are less costly to suppliers than the collateral requirements included in ComEd's current one-year REC contracts. Moreover, Staff believes that this language would comport with the process described in the IPA response to ComEd's objections.

5. IPA Position

The IPA commits to negotiating short-term REC collateral requirements and other contract provisions as part of the contract terms and conditions negotiations. Such negotiations will include the Procurement Administrator, bidders, utilities, Staff, and the Procurement Monitor. Therefore, the IPA recommends that this aspect of the Plan not be amended as sought by ComEd.

The IPA, however, agrees with Staff that the Plan and the contract terms should incorporate contingencies and terms that will permit ComEd and AIC to satisfy the RPS adopted under prior and future procurement events, where a supplier defaults on a short-term REC contract. In its reply to the various responses to the objections to the Plan, the IPA proposes that in the event of a supplier default, ComEd and AIC purchase replacement RECs using collateral on hand from the defaulting supplier when the defaulted volume represents more than 5% of the total number of RECs that were secured for that compliance year. If the defaulted amount is less than 5% of the total number of RECs that were secured for that compliance year, the IPA proposes that the vendor surrender the collateral, but that the utility need not replace the REC volumes. The IPA also suggests that it conduct any procurement required to replace the short-term RECS.

6. Commission Conclusion

Page 4 of the Plan discusses renewable energy resources. As an initial matter, the Commission disagrees with ComEd's interpretation of the IPA Act that there is no need for a utility to replace short-term RECs in the event that a supplier fails to deliver the contracted amount. Such an interpretation conflicts with the underlying intent of the statute that RECs actually be purchased and possession taken by the Illinois utility. Failure to deliver by a supplier does not absolve a utility of its RPS obligations when alternatives exist.

In addition, the Commission finds ComEd's proposed exile of a supplier to be too extreme in the event of a default. While performance under any contract is to be encouraged, barring a defaulting supplier from providing RECs in the future may cause more harm to customers in the long run than the harm caused to customers by the default . A less extreme but still meaningful alternative must be identified.

Staff recommends that the Plan be modified to allow stakeholders the opportunity to vet WOW's alternative proposal for liquidated damages as well as other credit requirement proposals that may minimize costs ultimately incurred by customers relating to the utilities' one-year REC contracts. Staff further suggests that any alternative credit requirements should be acceptable to both utilities in order to unify the credit requirements for short-term REC contracts to the maximum extent possible. To the extent that any such damages/credit requirements are designed to replace the required missing short-term RECs, the Commission finds this proposal reasonable. The Plan should be modified to provide for the implementation of this solution in accordance with Section 16-111.5(e)(2).

In addition, if a new RFP must be issued, the Commission considers it appropriate for any replacement short-term RECs to be procured by the IPA. The IPA's contingency plan for supplier defaults exceeding 5% of the RECs secured for the Plan year, however, is perhaps too vague. Specifically, the proposal fails to deal with several issues of timing. For instance, at what point in time does the IPA plan to hold these procurement events (multiple times per year, once per year, at the next regularly scheduled REC procurement event)? What vintage RECs would be procured? If the default is not even detected until after the relevant Plan year, will the IPA try to procure RECs under the previous year Plan or the current Plan? Finally, if the contract defaulted upon was for both energy and RECs, should the IPA seek to replace both or just the RECs. To what extent (if any) should options be written into contracts to allow for non-faulting suppliers to make up for defaulting suppliers' quantities? Because the

IPA's contingency plan fails to address these questions (and perhaps others that have not occurred to the Commission), the Commission is reluctant to approve the IPA's contingency plan for replacing RECs. Furthermore, the Commission sees no urgency to deal with this issue. There is no evidence that there have been any REC supply deficiencies due to supplier defaults, to date. Hence, rather than approve the IPA's contingency plan, the Commission suggests that the IPA develop a more detailed proposal and include it with next year's procurement Plan.

F. Oversubscription

1. ComEd Position

Both of the prior Plans included a 10% increased purchase volume for the peak periods in the months of July and August. The pending Plan includes the same requirement. ComEd argues that the continued inclusion of the 10% oversubscription in July and August is unsupportable, risky, and should be removed.

Using the IPA's own methodology, ComEd states that it assessed whether the risk associated with weather driven price spikes in the summer would be reduced by purchasing more than 100% of expected monthly requirements for peak periods in July and August. According to ComEd, the first step in this process was to determine the average portfolio energy cost assuming a high case (spot prices +40%, spot load +10% for July and August) and a low case (spot prices -30%, loads -8% for July and August). ComEd then analyzed three situations where purchases were made at 110%, 120%, and 130% of July and August peak loads. ComEd states that no correlation was assumed between spot prices and gross-up factors consistent with historical monthly data.

ComEd graphically provides the results of this analysis and contends that it shows the weakness of any argument for over-hedging in July and August. According to ComEd, this is due to the fact that market prices are low, and even with 40% price stress, the cost of spot market purchased power will be below the average embedded portfolio cost. ComEd contends that even without the benefit of the extra 10% hedge, the average portfolio cost will drop in the high case. ComEd argues that procuring more energy than is forecast to be needed during summer months, while hedging against higher than expected loads and prices, adds additional risk to the portfolio on balance.

ComEd maintains that historical experience underscores the likelihood that this approach will add cost. ComEd states that while it may pay off in some years, to date the over-hedging gamble has increased consumers' costs by $1.6 million since the 2008 procurement. Reproduced below is a table that ComEd says contains the outcome of each year's over-procurement.

July/August	Excess Purchased (MWh)	Weighted Avg. RFP Price ($/MWh)	Weighted Avg. Peak Price ($/MWh)	Benefit/(Detriment)
2008	96,480	94.79	86.42	($807,538)
2009	316,800	43.3	32.39	($3,456,288)
2010	446,400	49.8	55.68	$2,624,832
Total	859,680			**$ (1,638,994)**

In its consideration of the last procurement plan in Docket No. 09-0373, ComEd observes that the Commission approved 10% oversubscription cautiously, noting both the lack a rigorous analysis supporting it and that the data showing increased costs was still limited. Once again, ComEd argues that there has been no rigorous showing of any benefit for this over-hedging. According to ComEd, both rigorous prospective analysis and the weight of actual data point to the riskiness and expense of this strategy. Given the volatile nature of prices and loads, ComEd continues to recommend that 100% of expected requirements are purchased for all periods of the current plan year. ComEd believes there is no reason to go beyond this.

2. IPA Position

In support of its position, the IPA maintains that the potential for spikes in consumption in the portfolio are greatest during the July and August peak periods. The IPA contends that oversubscription by 10% will mitigate weather risk associated with this period. The IPA concedes that prices in the current market are relatively low, but insists that future spot prices can be far above current future prices due to variables in plant outages, transmission constraints, natural gas prices, and evidence of growing economic recovery. The IPA notes that the Commission approved oversubscription as a hedge to price risk in the prior Plan in Docket No. 09-0373. The IPA urges the Commission to be consistent with its prior Orders.

3. AG Position

In its Brief on Exceptions, the AG argues that the IPA has provided sufficient justification for its 10% oversubscription proposal. The AG contends that ComEd's analysis amounts to simply a few meaningless data points. The AG urges the Commission to defer to the IPA's judgment in the interest of protecting customers.

4. Commission Conclusion

At pages 28 and 45 of the Plan, the IPA references its proposal for AIC and ComEd, respectively, to include a 10% oversubscription for the peak periods in July and August. The Commission appreciates the IPA's effort to ensure that customers will have sufficient power during peak periods. In the last procurement docket, the

Commission deferred to the IPA's judgment on this issue even in the absence of analytical data supporting 10% oversubscription. In that docket, however, the Commission also advised the IPA that quantitative analysis on this issue would be useful if the IPA sought to continue this practice. Specifically, the Commission found that, "performance by the IPA of a quantitative analysis on the hedging issue in preparation of its next filed Plan would be beneficial to the assessment of this issue." (Docket No. 09-0373 at 160) Unfortunately, the IPA did not heed this advice and provided no analysis in support of the 10% oversubscription proposal.

ComEd, on the other hand, has provided an analysis utilizing historic data for the past three years. In 2008, when the utilities developed their own procurement strategy before the IPA was organized, 10% oversubscription unnecessarily cost ComEd customers $807,538. In 2009, 10% oversubscription unnecessarily cost ComEd customers $3,456,288. In 2010, 10% oversubscription saved ComEd customers $2,624,832. Altogether, 10% oversubscription unnecessarily cost ComEd customers $1,638,994. What the Commission gleans from this information is that a 10% oversubscription in the months of July and August does not necessarily benefit customers.

While the possibility of sometimes "winning" and sometimes "losing" is an inherent part of any hedging measure, the Commission is hesitant to continue relying on the IPA's recommendation on this issue without any quantitative analysis demonstrating the likelihood of benefits to customers. Many variables are present in any such analysis, and the Commission recognizes that the results would be far from perfect. But here, the IPA has neglected to provide any quantitative analysis to support its proposal despite being advised to do so in Docket No. 09-0373. In the absence of any such analysis to rely upon, the Commission finds that 10% oversubscription in the peak periods of July and August is unwarranted and directs that the Plan be modified to reflect this conclusion. The IPA is free to make this proposal in future Plans but is again cautioned to provide some quantitative support if it chooses to do so.

G. Energy Hedges - Financial Swaps v. Physical Transactions

1. AIC Position

AIC understands the Plan to state that the IPA will procure physical transactions at least for the 2011 procurement process and will monitor developments and make on-going recommendations in future procurement years. AIC supports the transition from financial swaps to physical transactions (described on page 32 of the Plan) due to uncertainty surrounding the outcome of the Federal rule making process for recently passed derivative legislation. AIC recognizes that the rule making may adversely impact it and/or its customers. On page 27 of the Plan, however, AIC claims that the IPA provides a contradictory proposal by stating that the Procurement Administrator can make a decision during the 2011 procurement process between (1) physical transactions and (2) financial transactions that can be contractually converted from physical transactions. At a minimum, AIC urges the IPA to correct this contradiction.

But if given the choice, AIC prefers the language on page 32 of the Plan because it is the most conservative course of action given uncertainty in the rule making process and it removes any doubt as to what methodology would be used in the 2011 procurement process.

2. IPA Position

The IPA acknowledges AIC's concern that the Plan is contradictory in that it provides that the Procurement Administrator will have the discretion to revert back to financial swap contracts if deemed preferable to physical delivery of energy. The IPA maintains that the option of reverting back to a financial swap contract should be kept open in the event that clarity on the derivatives issue is achieved prior to procurement events. In addition, the IPA recommends the following amendments, which may alleviate some of AIC's concerns:

> On pages 27-28:
>
> Furthermore, if the procurement administrator, <u>after consultation with the IPA, utilities, Commission, and procurement monitor,</u> determines that financial swap contracts are still preferable to contracts for physical delivery of energy, the procurement administrator will be instructed to fashion the swap contract, ...
>
> On page 32:
>
> In summary and in light of the information currently available, the IPA recommends replacing financial swaps for the spring 2011 procurement event with those that settle physically within MISO. This would appear to be the most prudent course of action until the rule making process is better understood. <u>However, if the procurement administrator, after consultation with the IPA, utilities, Commission, and procurement monitor, determines that financial swap contracts are preferable to contracts for physical delivery of energy, the procurement administrator will be instructed to fashion the swap contract, as previously noted in the Plan.</u> The IPA will monitor the rule making process and recommend a course of action for procurement events beyond spring 2011 as the outcome of the current rule making process becomes clearer.

3. Commission Conclusion

The Commission understands that the IPA wants to keep its options open in this context if the forthcoming derivative rule leaves financial swaps as an attractive option. The Commission finds this position reasonable. The language that the IPA proposes for pages 27-28 and 32 of the Plan will help clarify the matter and is approved. If necessary, however, the Commission directs that substantively similar modifications be made to the Plan as it pertains to ComEd.

H. Exchange Traded Contracts

1. AIC Position

AIC understands the Plan to offer three methods by which it could execute contracts: 1) ISDA agreements for financial instruments such as fixed-for-floating swaps, 2) an EEI agreement for physical products and, 3) central counterparty clearing for standardized financial instruments on exchange traded contracts. While the first two methods have been approved in previous Plans, AIC relates that the third method represents a new option. Because AIC does not believe that the IPA has adequately described the process changes necessary to allow for clearing of transactions on exchanges, AIC recommends that the third method be eliminated from the Plan.

Specifically, it is unclear to AIC if the solicitation process would still include an RFP as has been done in past years or whether an exchange clearing represents a process change away from the RFP process. If so, AIC claims such a proposal has major ramifications that should be fully vetted. Assuming the IPA intends to continue to use the RFP process, AIC could envision a scenario where winning suppliers work in concert with the IPA, the Procurement Administrator, AIC, and an exchange to set up a pre-defined transaction for clearing on the exchange. Under such a scenario, AIC states that the non-price contract terms would be defined as part of the IPA RFP process and would be in the form of an ISDA or EEI contract. AIC asserts that a standardized form of an exchange traded contract would not include the product specific contract language that is required for an IPA procurement event. AIC states that the IPA proposal, which AIC supports, is for it to procure physical products during the 2011 procurement cycle. AIC contends that under a scenario where AIC procures physical products, an exchange cleared product adds no value to the process and potentially adds costs to consumers. If, however, the Commission determines that central counterparty clearing should be included in the Plan, AIC indicates that the Plan should specifically state the IPA's intent to only allow the utilization of standardized financial instruments on exchange traded contracts when they meet the specifications, credit, and delivery requirements, which AIC interprets to mean that they will meet all of the non-price terms of the IPA procurement process.

2. Staff Position

In Staff's view, AIC presents a cogent critique of the IPA’s proposal to add central party clearing for standardized financial instruments on exchange traded contracts. Staff understands AIC to argue that the IPA proposal has not been adequately defined, and that on the one hand, it may be inconsistent with the RFP process described in the PUA (which would have major ramifications that should be more fully vetted) while on the other hand, it may add nothing (or only additional costs) relative to AIC’s preferred procurement of physical products during the 2011 procurement cycle. Staff is convinced that AIC's arguments present reasonable grounds for further study of central party clearing for standardized financial instruments on exchange traded contracts, which Staff would urge the IPA to undertake. In particular, Staff states that it is the type of procurement mechanism that might be clarified through discussions with the Procurement Administrator, Staff, the utilities, and the relevant exchanges and clearing houses. Staff urges the IPA to initiate such discussions well in advance of next year's Plan. Afterwards, in 2011, Staff urges the IPA to present its investigative findings and any associated recommendations along with the next procurement Plan.

3. IPA Position

The IPA disagrees with AIC's recommendation to eliminate central counterparty clearing for standardized financial instruments on exchange traded contracts as a method to execute contracts. If central counterparty clearing meet the specifications, credit, and delivery requirements, then the IPA believes those offers should be allowed. Therefore, the IPA recommends that the Plan not be modified as suggested by AIC.

4. Commission Conclusion

Page 16 of the Plan identifies the three methods by which contracts can be entered into as a result of the procurement process. As noted by Staff, AIC raises some legitimate questions regarding the implementation of central counterparty clearing for standardized financial instruments on exchange traded contracts. The comments of AIC and Staff raise concerns for the Commission. The IPA's response to those comments has done little to allay the Commission's concern. Although the IPA's proposal may be a very good one, without more of an explanation of how central counterparty clearing on exchange traded contracts would actually work in conjunction with the various statutory requirements, the Commission is not inclined to approve it. Accordingly, the Commission directs that the Plan be modified to remove this method of contract execution. The IPA is free to renew this proposal in future Plans, but the Commission advises the IPA to provide an explanation of how its proposal would work and what the potential advantages are over the other two methods of executing contracts.

I. Optional Procurement Events

1. ComEd Position

The Plan authorizes the IPA to procure up to an additional 10% of portfolio requirements when market prices fall 10% below the average weighted price of existing supply agreements and below the price of supply from the most recent procurement event. According to ComEd, the IPA presents no analysis or justification in support of this proposal. In ComEd's view, this lack of support contrasts with the well documented analysis supporting the Plan's three-year laddered procurement strategy. ComEd asserts that analysis demonstrates that procuring energy relatively evenly over a three-year period presents the lowest price risk scenario. ComEd contends that the Plan makes no attempt to explain how procuring an additional 10% improves upon it.

Without any such analysis, ComEd fears that procuring an additional 10% of supply will increase price risk and not lower it.

In addition, ComEd claims it is unclear how the proposed additional procurement would work in practice as it takes months to run a fair and transparent RFP process. Furthermore, ComEd observes that the IPA does not explain how the process would react to changing market conditions. For example, if the IPA sees forward prices below its benchmarks and starts the incremental RFP, ComEd wonders if the IPA would then have to cancel the RFP if forward prices then increase above the benchmark. If the RFP is cancelled, ComEd asks who bears the costs of this failed RFP.

2. Staff Position

Staff disagrees with the IPA's proposal to engage in optional procurement events. In Staff's view, the proposal does not mitigate the risk of price decline as the IPA suggests. According to Staff, a price decline only poses a risk if the utility is hedged beyond 100% of its requirements. Staff also contends that it is not entirely clear what is meant by the phrase, “such prices are below the prices for the most recently completed planning year procurement event.” (Plan at 17) Staff finds the phrase ambiguous for two reasons. The first reason is that each procurement event generally results in the purchase of several contracts with a range of prices covering the same delivery period. It is unclear to Staff if the IPA’s proposal that the trigger be when the “market indices” (which are generally considered to be averages of current market prices) are below (1) the minimum, (2) the maximum, or (3) the average contract prices obtained in the most recent procurement event. The second reason that Staff finds the phrase ambiguous is that the plan is generally focused on finding combinations of contracts to cover 24 time periods per year (defined by month and on-peak versus off-peak sub-periods). A given time period may be covered by several different types of contracts. For example, Staff suggests July 2012 on-peak might be covered by a combination of July 2012 on-peak, July-August 2012 on-peak, and July 2012-May 2013 on-peak contracts. Staff says it could also include July 2012 ATC, July-August 2012 ATC, and July 2012-May 2013 ATC contracts. Staff claims each of these contracts can have very different market values.

To the extent that the proposal would lead to more than the otherwise planned additional 35% of expected load being hedged for each of the last two years covered by the Plan, Staff suggests that the planned hedging levels may already be too high if the contracts entail substantial risk premiums. In this regard, Staff notes that NYMEX futures prices for latter-year electricity contracts have been considerably higher than for early-year contracts. Whether this is evidence of substantially higher risk premiums for latter years may be difficult to assess, but Staff believes that such should be considered by the IPA, and should lead to more caution about expanding the degree of long-term hedges.

While it is unclear to Staff just how many of these incremental procurement events might be held under the IPA’s proposal, Staff believes that each such event would add considerable costs to the entire procurement process. Such costs are in the form of time and money spent for a Procurement Administrator and Procurement Monitor and by the Commission, Staff, and utilities. Staff is particularly concerned that the IPA itself does not have the time and resources available to pursue "optional" activities. For reasons that continue to elude Staff, the IPA generally hires Procurement Administrators several months beyond the planned dates presented in the procurement plans. This past performance raises doubts in Staff's mind about the IPA's ability to handle the additional responsibilities associated with this and other new proposals. Staff recommends that the IPA remove all the above-cited portions of the Plan dealing with optional procurements and incremental procurement events.

3. IPA Position

In response to the objections of both ComEd and Staff, the IPA asserts that neither cites to a provision of a statute that limits procurement cycles to once a year. While its proposed optional incremental events may not be frequently used, the IPA believes eligible retail customers may benefit where more frequent procurements result in a lower price for energy. In the IPA's view, this option should also remain open should future procurement plans move towards a multiple or continuous procurement cycle – an issue that the IPA sought additional comment on for future consideration. Therefore, the IPA recommends that no changes be made to this aspect of the Plan. The IPA does not specifically address Staff's concerns about the IPA's ability to manage such optional activities.

4. AG Position

In its Brief on Exceptions, the AG asserts that given the recent market price decreases and the General Assembly's goal that the IPA obtain electricity supply at the lowest cost over time, it is reasonable for the IPA to include optional procurement events in its Plan so it might capture declining prices. The AG states that the Plan calls for the "authorization of the Commission" for such procurements to occur and limits participation to bidders qualified in, and the terms and conditions agreed to in, the Spring 2011 solicitation. (See Plan at 17) The AG contends further that how the optional procurements would work is clear from the Plan. The AG also argues that the IPA is capable of conducting such optional procurements along with its other responsibilities.

5. Commission Conclusion

Page 17 of the Plan describes the IPA's proposal for optional energy procurement. The Commission appreciates the IPA's interest in keeping costs low for customers, but has some concerns with this specific proposal. As ComEd notes, it is unclear how the proposed additional procurement would work in practice as it takes months to run a fair and transparent RFP process. Furthermore, if the IPA sees forward prices below its benchmarks and starts the incremental RFP, the Commission wonders if the IPA would then have to cancel the RFP if forward prices then increase above the benchmark. If the RFP is cancelled, the Commission also wonders who bears the costs of this failed RFP.

Additionally, the Commission questions the IPA's wisdom of taking on additional responsibility at this time. Organizing and implementing procurement events require many resources and a great deal of attention. As is clear from the record, the Plan approved in Docket No. 09-0373 has not yet been fully implemented. Given this fact and the many concerns about the process for securing renewable energy under the prior Plan, the Commission is hesitant to authorize the IPA to take on additional work. The Commission agrees with the IPA that nothing in neither the IPA Act nor the PUA limit or restrict the type of optional procurement events described in the Plan, but the Commission is not prepared to agree to a Plan that would divert the IPA's attention from the main task at hand at this time. The IPA is welcome to propose such optional procurement events in future Plans that clearly set forth the potential benefits to be derived there from and demonstrate that the IPA has sufficient resources to undertake such efforts. Accordingly, the Commission directs that the Plan be modified to remove those portions addressing the optional procurement events.

J. Multiple Procurement Cycles

1. RESA Position

RESA supports the concept of introducing more frequent procurement events as one of several possible procurement approach modifications that can result in more market responsive and market reflective default service. Although the Plan discusses the possible value of moving toward multiple procurement cycles, RESA complains that the Plan makes no real progress toward doing so. RESA nevertheless commends the IPA for requesting comments from other parties in response to RESA's comments, which RESA interprets as the IPA's intention to address this matter in this proceeding.

According to RESA, generally, utility default service procurement should result in market reflective price signals. RESA asserts that continued progress toward a competitive electric market is the best way to help all consumers balance price risk and budget certainty while also providing innovative and customer-driven value-added services. RESA contends that successful retail competition will produce downward pressure on price, offer a variety of product options for end-use customers, increase conservation incentives, enhance customer service, improve environmental management, and hasten the introduction of new, innovative products. RESA argues that retail energy competition requires that default service pricing be properly structured; consumers must see a default price for electricity that reflects the actual market price of the electricity they consume.

RESA contends that the failure of long-term procurement contracts to reflect current wholesale market prices create inefficiencies in either direction. In the event that a utility's procurement costs are higher than those available in the wholesale market, then RESA says customers are harmed by having to pay higher prices. RESA asserts that in the event that wholesale market prices rise above the locked in utility costs, customers will receive the incorrect price signal that energy is less expensive than reality and potentially over-consume and face the risk of rate shock as those contracts end. In either case, RESA believes customers will be harmed.

RESA argues that the use of more frequent procurement events would enable the procurement of shorter-term contracts which could be procured closer in time to actual delivery of the supply. According to RESA, the use of such contracts will enable customers to see a default price that better reflects market prices and will minimize long-term contract hedging premiums that are associated with longer-term contracts procured far in advance of delivery. In RESA's view, better price signals will spur more thoughtful efficiency investments, wise energy usage, and spur development of the competitive market. Better accuracy reduces customer costs over the long-term. RESA believes a major benefit of having default prices reflect the market is that consumers who are on those default rates will be sent clearer price signals that, in turn, will cause more efficient energy usage.

In an effort to facilitate discussion of this matter, RESA provided PPL Corporation's ("PPL") Modified DS Program Product Procurement Schedules for the Residential Customer Class and the Small Commercial and Industrial Class. According to RESA, these schedules depict a laddered procurement approach that PPL is using for its default service solicitations in Pennsylvania. Rather than procure a large amount of supply all at once, far in advance of the actual delivery term for the contract, RESA explains that the PPL procurement approach relies on quarterly procurement of varying term contracts. In RESA's view, this approach results in a significant percentage of supply "refreshing" with market prices each quarter as the underlying contracts expire and are replaced with new contracts. While RESA would ultimately support a procurement plan that relies on predominantly shorter-term procurement instruments such as fixed priced contracts less than one year in duration and spot market purchases, RESA believes the PPL approach provides an example of a procurement plan that produces a laddered, stabilizing effect on prices, while also resulting in default service prices that track changes in the market.

In the event that more frequent procurement events are not adopted in this proceeding, RESA suggests that a definite structure and timeline be put in place toward that goal. In addition to soliciting written input from parties, RESA suggest that Staff conduct workshops, beginning in January 2011, after the close of this proceeding, on the subject of multiple procurement events. If consensus can not be reached, RESA states that Staff should make a recommendation to the IPA well in advance of the IPA's submission of next year's Draft Plan so that the IPA can give timely consideration to the inclusion of multiple procurement events in that Plan.

2. ComEd Position

ComEd does not believe that having many or continuous procurements would enhance the procurement process as RESA suggests. ComEd notes that there are costs to holding procurement events and it is doubtful that these costs would be offset by consumer benefits when holding numerous such events in a year. In addition, given the existing significant duties of the IPA in relation to the annual energy procurement event, the annual renewables procurement event, the long-term renewables procurement event, the numerous requests for workshops to be hosted by the IPA, and the very limited resources currently at the IPA's disposal, ComEd can not support the IPA taking on additional procurement events at this time.

ComEd claims further that RESA's objection lacks the specificity required to understand how its proposal for more frequent procurement events might be incorporated into the Plan. To properly assess such a proposal, ComEd contends more information is needed regarding such issues as the frequency of the proposed procurement events and lengths of contracts, along with how the costs associated with more frequent events could be mitigated. Even then, ComEd does not see how moving to continuous procurement with the resulting volatility in energy prices benefits customers or is consistent with the direction in Section 16-111.5(d)(4) of the PUA to seek price stability.

3. Staff Position

Staff does not necessarily oppose the concept of introducing more frequent procurement events or reducing how far into the future energy price hedges are established. Before doing so, however, Staff believes that the IPA should investigate any disadvantages that might accompany such action. Staff suggests that holding more frequent events could reduce the amount of supplier participation and the degree of competition per procurement event. Additionally, Staff is concerned that more frequent procurement events would increase administrative costs and burdens. Staff believes that the latter problem is exacerbated by the PUA's requirements that each procurement event utilize an RFP, a Procurement Administrator and a Procurement Monitor (each of whom are required to submit reports to the Commission), utility and Staff involvement, and specific Commission approval following each event.

Additionally, Staff fears that RESA's proposal to reduce how far into the future energy price hedges are established would expose customers to greater risk of price volatility, since nearer-term forward prices are more volatile than more distant-term forward prices. Staff adds that while, as RESA claims, contracts that extend out only a few months may result in tariffed prices that are more reflective of market prices, that same benefit could be produced by reducing the hedge ratio below the IPA-proposed 1.0 (and 1.1 for July/August on-peak). Alternatively, Staff claims it could be obtained simply through changes in rate design. Finally, if, as RESA claims, contracts that extend out only a few months would reduce premiums associated with longer-term contracts, Staff suggests even more significant savings could be obtained by reducing or eliminating the procurement of contracts that extend one and two years beyond the plan year (as well as by reducing the hedge ratios for the plan year), without altering the number of procurement events per year.

Staff asserts that current electricity future contract prices increase in relation to the immediacy of their delivery periods and that this potential evidence of risk premiums should be investigated by the IPA and considered when it proposes hedging levels. Staff maintains that while it is not necessarily opposed to procurement plans that would be more sensitive to short-term price fluctuations and less heavily hedged, Staff finds RESA's proposal in this regard too complex and costly to administer. Hence, Staff recommends that the Commission reject RESA's recommendations for inclusion in the instant Plan.

Staff says it is willing to work with the IPA, RESA, and other interested parties in developing other proposals for potential inclusion in future procurement plans. In particular, Staff suggests that the Commission's ORMD solicit written input on this matter, and Staff will prepare a report to be provided to the IPA prior to the publication of the IPA's next draft procurement plan. Staff states that this report will include explicit recommendations on how, if at all, Staff would propose to "enable customers to see a default price that better reflects market prices and will minimize long term contract hedging premiums that are associated with longer term contracts procured far in advance of delivery," as RESA put it.

4. Commission Conclusion

Providing customers with more accurate information regarding the actual cost of electricity is certainly a reasonable goal, but the Commission is concerned that using multiple procurement events to achieve this and other goals described by RESA is not appropriate at this time. As it stands, the record lacks any analysis of the disadvantages versus advantages of multiple procurement events. Staff raises legitimate concerns about whether holding more frequent events could reduce the amount of supplier participation and the degree of competition per procurement event. Administrative costs and burdens may increase as well. Therefore, until a proper analysis of advantages and disadvantages is complete, the Commission is reluctant to support multiple procurement events.

The Commission is also troubled by this proposal for an additional reason. As discussed elsewhere in this Order, the IPA is still attempting to complete the procurement set forth in Docket No. 09-0373. The Commission is not inclined to direct the IPA to conduct additional procurement events beyond what is necessary when it would appear be having difficulty (for whatever reason) implementing the last Plan. Moreover, it would be premature to require workshops in January 2011 to discuss multiple procurement events in light of the difficulties with the last Plan. Staff, including the ORMD, and others are free, however, to meet without being directed to do so by the Commission to discuss proposals for multiple procurement events in future Plans.

K. Full Requirements Products

1. CECG Position

In order to procure supply required to meet the needs of eligible retail customers, CECG believes that the Plan should be modified to use full requirements products. CECG states that the IPA is given discretion to procure products individually, or in combination. Because the shape and quantity of the load is not known, CECG points out that customers bear greater risk with separate block products--a fact that the IPA should consider, according to CECG. CECG also opines that the benefits offered by a full requirements approach have never been greater than they are apt to be in this upcoming procurement cycle due to the likelihood that the number of utilities' bundled customers and underlying load will be reduced, potentially dramatically. CECG claims that the advent of purchase of receivables/utility consolidated billing, an increasing number of ARES indicating an interest in serving residential and small commercial customers, and the development of various websites and referral programs support the notion that competitive electricity markets will continue and strengthen, and that eligible retail consumers currently served through the IPA portfolio may migrate towards ARES options. CECG also agrees with the IPA that these recent developments indicate that significant reductions to the barriers to retail competition in residential markets are on the near-term horizon and that the portfolio is exposed to load uncertainty risk.

In terms of risk, CECG contends that it is important to keep in mind that costs to customers may include not only the prices paid by customers for IPA-procured supply, but the risks and lost opportunities they may face under a particular IPA plan. CECG argues that a full requirements approach will limit risk to customers by shifting risk from the IPA, ComEd, and AIC to wholesale suppliers, while promoting opportunities for customers by providing well-defined, competitively-procured default service supply that provides appropriate benchmarks for comparisons to RES product offerings. CECG indicates that risks to ComEd and AIC are essentially risks to their customers since the utilities pass the risks that they face onto their customers.

To demonstrate the value of shifting risk to the supplier, CECG offers an example concerning the Wellsboro Electric Company ("Wellsboro"), a Pennsylvania utility procuring its default service requirements through a managed portfolio approach. CECG relates that Wellsboro faced a market "surprise" and sought permission from the Pennsylvania Public Utility Commission on January 30, 2008 to recover more than $2 million in additional congestion costs from its customers because of an unexpected congestion event. CECG states that Wellsboro's customers did not have the "insurance" provided by a full requirements supplier for such an event and, as a result, had to bear the burden themselves for the rise in costs, as the Pennsylvania Public Utility Commission approved the pass through of such costs on February 28, 2008.

CECG contends that an IPA plan relying on full requirements products provides a proper balance by obtaining the most competitive prices for consumers, while appropriately placing risks such as volume risk on wholesale suppliers. In support of its position, CECG relies on a study of Pennsylvania's energy future by Dr. Susan Tierney, an energy policy expert, former Assistant Secretary for Policy at the U.S. Department of Energy, and former Commissioner at the Massachusetts Department of Public Utilities. CECG asserts further that through competitive full requirements procurements, wholesale suppliers bring many benefits because of their abilities and skills. Such abilities and skills, CECG points out, include expertise and ability to appropriately utilize load data to manage portfolios of supply at the least possible cost. CECG adds that suppliers are able to draw from their substantial experience throughout PJM, MISO, and other jurisdictions to develop proprietary models of customer behavior and switching patterns, to refine these models, and to better analyze the local data provided by utilities. CECG states that these wholesale suppliers pass on the efficiencies they achieve due to their sophisticated risk management skills and experience in the form of more competitive bids for full requirements products in competitive procurements. CECG claims that wholesale suppliers have already invested in, and continue to make significant investment in acquiring, experts in each specific type of market which makes up full requirements supply.

Speaking of its own experience and abilities, CECG states that it has hundreds of employees involved in the process of providing full requirements service to utilities and customers around the country, serving tens of thousands of MW of various types of full requirements load from coast to coast. CECG asserts that it employs a team of seasoned portfolio managers for large regional portfolios that serve its customers' full requirements loads. CECG says that it must ensure that any transaction that goes into its entire portfolio of obligations is accounted for at the end of each day, and that requirements for the entire load are met continuously for every hour of every day of every week. CECG further claims that a team of strategists continuously develops and improves computer models to keep track of all of the variable inputs that go into providing full requirements service; these strategists provide and analyze various scenarios that CECG's portfolio managers may face. In addition, CECG says a fundamentals group constantly researches basic supply and demand in fuel and power markets in order to monitor macroeconomic trends that affect the costs of serving load. CECG adds that a 24-hour power trading desk trades power in the hour-ahead, day-ahead, and week-ahead markets each day of the week, in order to help manage CECG's supply portfolio. CECG reports that power managers and traders monitor and trade in not only the PJM and MISO markets, but also those in New York, New England, and other markets throughout the U.S.; fuel managers do the same as fuel markets have direct effects on power markets. CECG claims that similar resources focus on fuel oil, natural gas, coal, currency, emissions, and renewable energy markets. CECG asserts that full-time meteorologists on its team continually monitor and predict the weather, so that its team can plan for weather effects on load requirements, and adjust supply accordingly. CECG states that the task of meeting full requirements load supply additionally requires controllers, schedulers, and dispatchers. CECG claims that supporting all of these operations is a team of regulatory specialists and attorneys that monitor and participate in regulatory and legal activities which affect energy markets.

CECG asserts that it is important to point out certain significant results from a recent analysis ("2010 Procurement Structure Analysis") conducted on behalf of Narragansett Electric Company d/b/a National Grid ("National Grid"), and filed in the Rhode Island Public Utilities Commission's proceeding to consider National Grid's procurement structure for Standard Offer Service, Rhode Island's equivalent of utility supply service to eligible retail customers. CECG contends that the 2010 Procurement Structure Analysis provides an important and unique technical assessment based on advanced modeling, to compare and contrast the relative costs and risks of different approaches to serve mass market customers, and how different approaches could impact customers' supply rates. CECG states that while the analysis suggests that a managed portfolio approach may, in fact, generally be cheaper than a full requirements structure, it is cheaper only by the narrowest of margins – roughly only $0.72/MWh. According to CECG, for this very limited benefit in cost due exclusively to the price for supply, consumers will be faced with considerably more costs due to increased risks.

CECG recognizes that wholesale suppliers bidding on full requirements products may place a certain value on the risk that they assume, for instance, for customer migration. CECG explains that the calculation for this monetization will depend on an individual wholesale supplier's perception of the level of such risk, its ability to manage the risk, and its appetite for assuming the risk. CECG claims that by removing the potential for monetization and management of this risk by suppliers, a managed portfolio approach takes the actual risk and places it on consumers. In other words, it is a zero sum game. CECG believes that this type of shifting of risks directly to consumers fundamentally alters the nature of the product being provided.

According to CECG, proponents of a managed portfolio approach often make claims that these monetizations and costs are exclusive to full requirements products. CECG asserts that this claim represents the false assumption that products such as block products in a managed portfolio approach will avoid (or else place on customers) most of the risks that are monetized in a full requirements product. CECG asserts that block products include all of the same risks – and, in turn, monetization of risks – as full requirements products for items including, but not limited to, rising fuel costs, inflation, new energy taxes, market rule changes, market price changes prior to bid acceptance, and changes in credit standing. CECG contends that it follows that the only risk that may not be priced into the costs for block products is that of load variation, including variation due to customer migration.

CECG observes that detractors of full requirements structures also often suggest that a profit is added into a bid which is otherwise avoided when purchasing other products that may be procured under a managed portfolio approach. CECG argues that any product that is purchased in the wholesale markets – e.g., whether a full requirements product, a block product, or a spot market purchase – will include in its price some level of profit that the supplier is willing and able to receive. CECG asserts that basic economic principles suggest that the price that a seller is "willing" to sell his product for will be constrained by the price he is "able" to sell his product for, so that in a competitive procurement, where only the lowest price from a pool of sellers is accepted, each seller will have an incentive to drive down the price at which he is "willing" to sell his product. CECG believes this competitively constrained price for a full requirements product will include a seller's perceived monetizations of risk as well as a profit on the overall full requirements product. CECG suggests that depending on a supplier's perception of the level of risks, its ability to manage risks, and its appetite for assuming risks, a supplier may have an ability to drive down further its underlying costs and overall prices. CECG claims that this especially is true for suppliers that are able to spread their costs across a large portfolio of supply obligations – if a supplier experiences lower revenue or a loss due to one of its obligations, for example, it is able to offset it against earnings across its entire portfolio of obligations. According to CECG, a utility relying on a managed portfolio approach has neither the competitive incentives to drive down its costs for managing risks nor the ability to hedge its obligations and costs across a broad, multi-regional portfolio.

CECG recognizes that a transition to a full requirements product can not occur overnight. CECG recommends that a full requirements product be used for 25% of that which is to be procured in the current procurement cycle, which will allow Illinois to achieve some of the benefits associated with a full requirements product while permitting an orderly transition under the current laddered approach.

2. IPA Position

The IPA opposes CECG's proposal at this time. The IPA states that Section 1-5 of the IPA Act provides that it is required to develop "procurement plans to ensure adequate, reliable, affordable, efficient, and environmentally sustainable electric service at the lowest total cost over time, taking into account any benefits of price stability . . . ." Bearing in mind its obligation under the IPA Act, the IPA questions CECG's assertion that full requirements products entail less risk for customers than block contracts.

While it is willing to discuss the use of full requirements products in future Plans, the IPA continues to believe that its current approach is preferable to full requirements contracts. At the conclusion of the 2009 procurement cycle, the IPA states that it commissioned a study on the 2009 AIC procurement against another procurement in the MISO footprint. The IPA states that AIC's procurements used three separate sealed-bid, pay-as-bid auctions to purchase standard energy products, capacity, and RECs, whereas FirstEnergy Corporation solicited full requirements service bids, which included energy, capacity, transmission, and ancillary services, among other components, in a single, consolidated product. According to the IPA, the analysis showed that under the market conditions that existed at the time of the auction bidding, the AIC procurement approach produced lower energy prices for ratepayers.

3. Commission Conclusion

Although CECG raises interesting points in support of full requirements products, the Commission is reluctant to adopt such an approach to procuring power at this time. Among the Commission's concerns is the simple fact that it is not entirely clear how

CECG's proposal would be implemented. It is particularly unclear how to translate CECG's recommendation that full requirements product be used for "25% of that which is to be procured in the current procurement cycle," into targets for the Procurement Administrator. A comparison of the load forecasts and the pre-existing contracts shown in the Plan reveals widely varying needs for additional electricity, depending on the month and time period. In this regard, CECG is not clear on what it expects the IPA to seek in full requirements RFPs. Perhaps after discussions with the IPA and other stakeholders, CECG would be able to offer a more specific proposal pertaining to a future Plan. Any future proposal, however, should also clearly address another of the Commission's concerns, which is whether a full requirements product satisfies the statutory requirement for standard wholesale products. Finally, while CECG seems to be correct that full requirements contracts eliminate risks which the IPA Plan leaves unhedged, the Commission is not convinced that eligible retail customers are in urgent need of eliminating such risk. Accordingly, the Commission will not adopt CECG's proposal in this Plan.

L. Application, Credit, and Contracting Process

CECG recognizes and appreciates the improvements that have been made in the two prior procurement cycles in standardizing products and contracts. CECG recommends that the Commission take this opportunity to make further refinements in this year's Plan. CECG states that currently, each product (energy, capacity, and renewable energy) has a separate comment process and application process, and the process is different for ComEd and for AIC. CECG believes that standardization of the procurement applications themselves would decrease the administrative burden on all parties. Ideally, CECG believes this would take the form of a single application and guarantee for all products, with bidders indicating for what products they are applying and in what service territory(ies). According to CECG, relieving the administrative burden on prospective bidders permits those entities to focus more time and resources on the bid itself, which is where consumers realize the benefits of competition. CECG believes that standardization mitigates the administrative burden on the Procurement Administrator, the Procurement Monitor, and the Commission. CECG contends that it would be less cumbersome and less expensive for bidders to use a single guarantee for all products and a single credit line to manage under a master agreement, thus potentially leading to an increase in the number of potential bidders and a decrease in the cost for the product.

CECG adds that the process could also benefit from streamlining and standardizing contracts. CECG states that previously, the three products were procured under three distinct contracts - one for energy, one for capacity, and a third for RECs. CECG adds that new agreements are entered into each year for each product, with language in the agreements inserted to try to tie them together, both across products and across years. CECG believes that entering into new contracts for each product each year is inefficient. At a minimum, CECG claims power and capacity should be procured under the same agreement, as is standard market practice, either through an EEI Agreement or ISDA Agreement with a Power Annex. CECG asserts that ideally

RECs could also be procured under the same EEI or ISDA Agreement, as well. According to CECG, the master agreement could and should be used for procurements in multiple years, updating as necessary through the annual process, rather than utilities modifying the contracts year to year unilaterally.

In response to CECG, the IPA states that it recognizes the value of standardization and is seeking to unify product requirements, such as the move towards unifying the REC procurements. The IPA indicates that it will continue to work towards this goal with the utilities, wholesalers, Procurement Administrators, and Staff.

The Commission supports efforts to standardize the procurement process as much as possible. For this reason, the Commission encourages the IPA, Procurement Administrator(s), and other stakeholders to work together toward that end. The IPA should consider using an RFP calling for a single application and guarantee for all products, with bidders indicating for what products they are applying and in what service territory(ies). Efforts to streamline and standardize contracts should also be seriously undertaken during the contract development stage of the process.

M. Regulatory Uncertainty

While CECG commends the IPA and the Commission for reducing the time period between submission of bids and contract execution, CECG contends that the time period between the submission of bids and the notification of potentially winning suppliers should be shortened, to the extent possible. CECG observes that previous IPA Plans resulted in submission of potentially winning bids in a shorter time frame than the outside limits established under the law, and the Commission likewise expeditiously evaluated and approved the results of the procurement events. CECG, however, believes further improvements can be made in shortening the time period for “informal” notification to potentially winning bidders for the AIC competitive procurements.

According to CECG, the longer that bids must remain open, and be subject to the possibility that bids will be renegotiated or rejected during a review process that does not define the criteria for such renegotiation or rejection, the greater the likelihood that consumers will ultimately be economically harmed. CECG states that while bids are held open during the review process, bidders retain the risk that market prices will change suddenly or unexpectedly. CECG insists that this risk is particularly important in procurement events involving block energy products, given the volatility in today’s market. CECG asserts that potential suppliers have to incorporate such risks in their bids to account for this time lag. CECG claims these risks will necessarily translate into higher bid prices.

CECG believes that decreasing the length of time between submission of the bid and notification of likely bid award decreases the risk that suppliers bear, which would likely lead to lower overall bid prices and would be consistent with the statute. Given that the block energy products are standard wholesale energy products, CECG claims that the review of these bids should be relatively straightforward, and should not require negotiation or additional review time. CECG appreciates the efforts by the Procurement Administrators to convey their recommendations to the Commission expeditiously, and the Commission's prompt action in reviewing those recommendations. CECG claims that any time that can be shaved off of the current process is of benefit to suppliers, and therefore ultimately will inure to the benefit of ratepayers.

CECG suggests that a potential solution to the above concern can be addressed by requiring the Procurement Administrators to notify likely winning and losing bidders (e.g., whether or not the bidder's name is being submitted to the Commission as one of the group of qualified bidders with the lowest overall prices), subject to Commission approval, as soon as possible on the same calendar day that bids are submitted. CECG reiterates its belief that the review of bids for standard block energy products should be relatively straightforward, and should not require additional time. CECG suggests that at a minimum, bidders should receive notification of the Procurement Administrator's recommendation to the Commission at substantially the same time that the recommendation is delivered to the Commission. CECG points out that this process was followed throughout the ComEd procurement processes, but was not followed in the AIC procurement processes, despite requests over the course of several years. CECG contends that this is of particular importance for the energy procurement, in which there is the greatest price volatility.

The Commission understands CECG's concerns. At a minimum, the ComEd and AIC procurement processes should be handled similarly. No party has offered any, and the Commission is not otherwise aware of any reason why the Procurement Administrator could notify bidders in the ComEd procurement whether their bids were being submitted to the Commission at substantially the same time of the submission to the Commission, but not be able to do so for bidders in the AIC procurement. The Commission directs that bidders in both the ComEd and AIC procurements be treated the same consistent with the applicable law.

N. Technical and Miscellaneous Corrections

1. Capacity Resources

The Plan provides that ComEd will continue to procure capacity from PJM under PJM's RPM program. At the end of the section on capacity resources, however, ComEd claims that the Plan contains a puzzling paragraph that states that the Procurement Administrator shall procure capacity resources for ComEd. ComEd asserts that this is inconsistent both with the rest of the capacity resource section of the Plan and with how ComEd has historically procured capacity. ComEd believes that this is an inadvertent mistake. ComEd adds that any capacity acquired by the Procurement Administrator for ComEd would be unnecessary and will simply increase customers' costs. ComEd notes that the language in this section appears to be taken verbatim from the section in the AIC portion of the Plan discussing capacity resources. ComEd understands that the Procurement Administrator procures capacity for AIC. ComEd recommends that the paragraph in question be stricken. The IPA agrees with ComEd's objection and recommends that the paragraph on page 52 beginning with “The IPA’s procurement administrator will issue solicitations . . .” be removed from the Plan. The Commission concurs that this correction should be made and directs that it be done.

2. Illinois Preference for Renewable Resources

Section 1-75(c)(3) of the IPA Act provides that “After June 1, 2011, cost-effective renewable resources located in Illinois and in states that adjoin Illinois may be counted towards compliance with the standards set forth in paragraph (1) of this subsection (c).” Given that the pending Plan involves the procurement of renewable energy resources for the period of June 2011 to May 2012, the IPA will no longer be limited to Illinois-based renewables and may look to adjacent states to acquire renewable energy resources. AIC, CECG, and Staff note, however, that the Plan appears to inadvertently limit the IPA to procuring only Illinois-based renewable energy resources for AIC even after June 1, 2011. That portion of the Plan concerning ComEd is consistent with Section 1-75(c)(3). AIC, CECG, and Staff recommend revising the Plan to make it clear that the evaluation methodology will change for the upcoming procurement cycle and will no longer include a preference for Illinois resources after June 1, 2011. The IPA recommends incorporating AIC's suggested language to accurately reflect Section 1-75. The Commission concurs that this correction should be made and directs that it be done.

3. Updated Load Forecast

ComEd notes that the Plan relies upon the data contained in the forecast that it provided to the IPA on July 13, 2010. ComEd observes, however, that the IPA attached to the Plan the forecast that ComEd provided to the IPA on July 15, 2009. In addition, ComEd claims it has been the practice in past procurement cycles for ComEd to update some information in its forecast, based on data that was not available in July, and to present the updated forecast in the procurement proceeding. ComEd continued that practice in this proceeding via its November 16, 2010 "Motion for Leave to File Updated Load Forecast." The updated load forecast is approximately 460 GWh lower because of lower load growth. ComEd recommends that the Plan be revised to incorporate the updated forecast. As with previous Plans, the IPA agrees that the Plan should be revised to incorporate ComEd’s updated forecast. The IPA states that it will modify the Plan accordingly should the Commission agree with this recommendation. The Commission agrees with this recommendation and directs that the Plan be modified accordingly.

4. Other Corrections

On page 24 of its objections, ComEd identifies several alleged technical corrections. Staff identifies what it identifies as Clerical/Typographical corrections at page 12 of its objections. On page 7 of its objections, AIC identifies what it describes as "Data Corrections."

The IPA agrees with the following corrections offered by ComEd and recommends their inclusion into the Plan:

- The 2011 demand response amount shown on page 41 as 42.0MW should be 42.9MW in accordance with the IPA filing dated July 15th.
- Table Q on page 43 should show average load in MWs rather than MWhs.
- In Attachment F to the Plan, the September 11 SF should be 1,829 not 2,615 and the Total should be 3,005 not 3,791.
- In Attachment F to the Plan, the October 11 SF should be 1,568 not 1,829.
- In Attachment F to the Plan, the column headings should refer to GWh not MW.
- In Attachment G to the Plan, the table heading for Average Load should be MWs and not MWhs.

AIC proposes to adjust Attachment D by correcting the quantity for January 2014 in the on-peak table. The IPA indicates that the correct values should be 750 MW for the 2011 IPA procurement (as opposed to 0 MW) and 650 MW for the 2012 IPA procurement (as opposed to 400 MW). The IPA recommends accepting the proposed amendments.

The IPA recommends accepting the correction that Staff identifies on page 3 of Attachment D to the Plan. Staff explains that there is a difference between the January 2013 row of Table I on page 30 of the Plan and January 2013 row of the otherwise identical Attachment D, page 3. The correct values can be found in the January 2013 row of Table I on page 30 of the Plan. AIC recommends making the same correction.

The Commission agrees that the corrections identified in this subsection should be made and directs that it be done.

VIII. FINDINGS AND ORDERING PARAGRAPHS

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

(1) ComEd and AIC are Illinois corporations engaged in the retail sale and delivery of electricity to the public in Illinois, and each is a "public utility" as defined in Section 3-105 of the PUA and an "electric utility" as defined in Section 16-102 of the PUA;

(2) the Commission has jurisdiction over the parties hereto and the subject matter hereof;

(3) the recitals of fact and conclusions reached in the prefatory portion of this Order are supported by the record and are hereby adopted as findings of fact;

(4) the load forecast for AIC attached to the IPA's September 29, 2010 petition should be approved; the load forecast for ComEd attached to the

IPA's September 29, 2010 petition, as modified to incorporate the update in ComEd's November 16, 2010 "Motion for Leave to File Updated Load Forecast" should be approved;

(5) the load balancing procedures which the IPA proposes for ComEd and AIC, including the proposal for modifying its portfolio for ComEd and AIC in the event of a significant shift in load as laid out in its September 29, 2010 Plan (See Plan at 33 and 49-50), are reasonable and should be approved;

(6) subject to the modifications explicitly adopted in the prefatory portion of this Order, the Plan filed by the IPA pursuant to Section 16-111.5 of the PUA should be approved; as modified, the Plan, and load forecasts found appropriate above, will ensure adequate, reliable, affordable, efficient, and environmentally sustainable electric service at the lowest total cost over time, taking into account any benefits of price stability; in making this finding, the Commission is not expressing its concurrence in every statement or opinion contained in the Plan and no presumptions are created with respect thereto;

(7) to facilitate the review process and to continue movement toward uniformity between AIC and ComEd Plans, in future Plans, the IPA is encouraged to include only once discussions that are identical for AIC and ComEd; to the extent Plans differ for AIC and ComEd, the IPA should highlight those differences or distinctions.

IT IS THEREFORE ORDERED by the Illinois Commerce Commission that subject to the modifications explicitly adopted in the prefatory portion of this Order, the Plan filed by the Illinois Power Agency pursuant to Section 16-111.5 of the Public Utilities Act is hereby approved.

IT IS FURTHER ORDERED that all motions, petitions, objections, and other matters in this proceeding which remain unresolved are disposed of consistent with the conclusions herein.

IT IS FURTHER ORDERED that, subject to the provisions of Section 10-113 of the Public Utilities Act and 83 Ill. Adm. Code 200.880, this Order is final; it is not subject to the Administrative Review Law.

By order of the Commission this 21st day of December, 2010.

(SIGNED) MANUEL FLORES

Acting Chairman