STATE OF ILLINOIS

ILLINOIS COMMERCE COMMISSION

Illinois Power Agency	**:**	
	:	**11-0660**
Petition for Approval of the 220 ILCS 5/16-111.5(d) Procurement Plan.	**:**	

ORDER

DATED: December 21, 2011

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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 d/b/a Ameren Illinois ("AIC"). 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 28, 2011, the IPA filed with the Commission its fourth 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 28, 2011; thus, the deadline is December 27, 2011. 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 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 28, 2011, 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. ("CCG") and Constellation NewEnergy, Inc. ("CNE") (collectively "Constellation"), Environmental Law and Policy Center ("ELPC"), Exelon Generation Company, LLC ("Exelon"), Illinois Competitive Energy Association ("ICEA"), Retail Energy Supply Association ("RESA"), the Solar Alliance, Comverge, Inc. ("Comverge"), FutureGen Industrial Alliance, Inc. ("FutureGen"), BlueStar Energy Services, Inc. ("BlueStar"), Ameren Energy Resources Company, LLC ("AERC"), the Interstate Renewable Energy Council, the Illinois Solar Energy Association, Wind on the Wires ("WoW"), the Vote Solar Initiative ("Vote Solar"), the Illinois Solar Energy Association ("ISEA"), the Interstate Renewable Energy Council ("IREC"), and Ameren Energy Resources Company, LLC ("AER"). The Administrative Law Judge granted each petition for leave to intervene. The City of Chicago (the "City") filed an appearance in the proceeding. Of those that intervened, AIC, ComEd, RESA, ICEA, the Solar Alliance, FutureGen, Exelon, Comverge, Constellation, and WoW each filed objections to the plan. Commission Staff ("Staff") filed objections as well.

At its October 5, 2011 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. Responses to Objections were filed by AIC, ComEd, RESA, ICEA, the Solar Alliance, FutureGen, Exelon, WoW, AER, the AG, IREC, ELPC, Vote Solar, and ISEA. Replies to Responses to Objections were filed by Staff, the City, the IPA, ComEd, AIC, the Solar Alliance, Comverge, FutureGen, WoW, ICEA, Constellation, RESA, IREC, and ELPC jointly with Vote Solar.

On November 15, and November 17, 2011, AIC and ComEd, respectively, filed a motion seeking leave to update its load forecast. Both indicated that the IPA Plan filed in this proceeding contemplated such filings to reflect ongoing increases in residential switching. In addition, a new statutory mandate requires the utilities to submit to the IPA an updated load forecast to the IPA. Section 16-111.5(k-5) of the PUA, which was added by Public Act 97-0616, requires that "[w]ithin 30 days of the effective date . . . each such utility shall submit to the [Illinois Power] Agency updated load forecasts for the period June 1, 2013 through December 31, 2017." No party opposed either motion and they were granted by the Administrative Law Judge.

A Proposed Order was served on the parties. Briefs on exception to the Proposed Order were filed by RESA, FutureGen, AIC, Staff, ComEd, WoW, and Comverge. Replies to briefs on exceptions were filed by Staff, RESA, AIC, WoW, ICEA, ComEd, and the IPA. The Commission has fully considered the briefs on exception and replies thereto in preparing 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 28, 2011, after receipt by the IPA of comments from others. Objections to and 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.

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

Subject to approval of the Commission, the IPA is required by statute to meet the electricity supply needs of the bundled rate customers of ComEd and AIC. It does so by developing and implementing electricity procurement plans designed to "ensure adequate, reliable, affordable, efficient and environmentally sustainable" electric service at the “total lowest cost over time,” while taking into account “any benefits of price stability.” In the 2012-2013 planning year, the IPA says its portfolios will supply approximately 40 million megawatt-hours ("MWh") to almost 4.5 million eligible customers of ComEd and AIC.

The Plan outlines a procurement strategy for the period of June 2012 through May 2017 based on detailed five-year demand forecasts provided by AIC and ComEd. Because existing contracts are in place for a 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. The RFPs will request bids for fixed price and fixed volume contract offers. The IPA proposes to hold the procurement events during the early spring of 2012 to secure the volumes of wholesale products identified in this Plan. The IPA proposes to extend the contracts of the current procurement administrators: National Economic Research Associates to administer the ComEd solicitations, and Levitan and Associates to administer the AIC solicitations.

The IPA plans to seek energy supply resources for the AIC and ComEd loads on a laddered three-year forward basis in volumes. The IPA indicates that capacity resources for ComEd will be delivered primarily through the PJM Interconnection ("PJM") capacity markets. For AIC, the IPA says capacity resources that are qualified by the Midwest Independent System Operator (“MISO”) to issue Planning Resource Credits (“PRC”) will be sought for the AIC load.

With regard to renewable energy resources the IPA states that renewable energy credits (“REC”) for multiple compliance years will be sought. Due to potential customer migration and the structure of the long-term power purchase agreements ("PPAs") for renewable energy in effect for the 2012-2013 through 2032-2033 compliance periods, the IPA says specific annual Renewable Resource Budgets are variable. The proposed process will establish a confidential budget threshold for a 12 year budget horizon, and utilize those budgets to structure REC contracts consistent with the solar and wind carve-outs specified in the Renewable Portfolio Standard ("RPS"). The IPA plans to seek to establish common REC contract terms including (1) collateral requirements that equal 10% of remaining contract value, and (2) unsecured credit limits for creditworthy REC suppliers, unless an alternative proposal is acceptable to the procurement administrators, the utilities, the IPA, Staff and the procurement monitor.

The IPA states that federal incentives to support the repowering of an existing power plant in Illinois as a Clean Coal Generation facility are available. The IPA proposes to solicit proposals from developers of such a plant to meet the state Clean Coal Portfolio Standard.

As prescribed in the prior 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 cannot be known, the IPA proposes to employ a portfolio distribution schedule that allows between 20% and 40% of projected loads to be procured in each of the three years prior to the delivery month. Within this range, 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.

According to the IPA, Illinois is in transition from an industry dominated by vertically integrated public utilities to one that relies on deregulated generation and wholesale commodity markets. To optimize portfolio design, the IPA believes it must closely monitor wholesale electricity markets, particularly the PJM, in which ComEd participates, and the MISO, in which AIC participates. In addition, the IPA must also closely monitor the retail markets in Illinois to understand the scale and scope of its tasks. In the IPA's view, the dynamic nature of these unique and evolving wholesale and retail markets poses challenges to efficient and effective procurement planning.

The IPA believes 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 notes that the Commission's Office of Retail Market Development ("ORMD") continues to pursue its mission to actively seek input from all interested parties and to develop a thorough understanding and critical analyses of the tools and techniques used to promote retail competition in other states. The IPA says the ORMD monitors existing competitive conditions in Illinois, identifies barriers to retail competition for all customer classes, and actively explores and proposes to the Commission and to the General Assembly solutions to overcome identified barriers.

The IPA also indicates that local communities are moving forward with municipal aggregation plans. According to the IPA, municipal aggregation occurs when local communities select an ARES for the eligible retail customers that reside within their municipal boundaries. Based on these factors and other indicators, such as the number of ARES registered with the Commission and the number of ARES registering with intent to sell into the residential sector, the IPA anticipates that the policy supporting competitive electricity markets will continue and strengthen, and that a portion of the eligible retail consumers currently served through the IPA portfolio will migrate towards ARES options.

IV. LOAD FORECASTS

Among the areas covered in the Plan are the ComEd and AIC load forecasts. The IPA states that pursuant to Section 16-111.5(d)(1) of the PUA, on July 13 and July 15, 2011, ComEd and AIC, respectively, submitted to the IPA separate load forecasts. Copies of ComEd's and AIC's load forecast submittals are included in Attachments B and A to the Plan.

The IPA indicates that it relies on load forecasts from ComEd and AIC as the best estimates for future consumption factored for the largely unknown variable of retail switching. Since the data projections are updated annually, the IPA readjusts load projections to account for the current view on retail switching and other factors affecting load size and shape. Given the increase in residential switching in the past year, the IPA seeks updated forecasts from ComEd and AIC in early November 2011 so as to improve the accuracy of purchase quantities resulting from the Plan. According to the IPA, such forecasts will be submitted to the Commission and to the IPA.

According to the IPA, the ultimate goal of the load forecast is not to identify the combined load of all customers of the utility. Rather, the 5-year hourly load forecast identifies load projections for “eligible retail customers” as defined above. The IPA states that ComEd and AIC apply statistically adjusted end use models as the basis of their load forecasting process. After adjusting consumption, data, weather, seasonal variables, and economic conditions, the IPA says detailed core consumption models are developed.

The IPA says the econometric models produce monthly sales forecasts for primary customer classes. Those base monthly forecasts are normalized for primary load variables (weather, economic growth, population, etc.) and combined with the hourly models to obtain on-peak and off-peak quantities for each month and each delivery service class. According to the IPA, the statistical models are measured for accuracy against past period consumption volumes for each customer class. The IPA claims that 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. The IPA says resulting high, expected, and low volume scenarios are generated.

A. ComEd's Load Forecast

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

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 for 2012 (756 gigawatt-hours ("GWh")), for 2013 (934 GWh), for 2014 (1,117 GWh), for 2015 (1,288 GWh), and for 2016 (1,471 GWh).

The IPA says it anticipates requesting validation of the ability to dispatch the Demand Response assets included in the forecast in the near future. The IPA also notes that these energy efficiency values are effectively treated as all other legacy supply contracts within the supply resources projections for the utility.

B. AIC's Load Forecast

As indicated above, Section 16-111.5(b) of the PUA requires that the procurement plan shall include an analysis of the impact of demand side initiatives established by Section 8-103(c) of the PUA. Those demand side initiatives include the impact of demand response programs and the impact of energy efficiency programs (both current and projected). The IPA indicates that recent activity in Docket No. 10-0568 leads the IPA to conclude that AIC does not have a valid demand response program. Specifically, the IPA notes that the Commission rejected AIC's request for a proposed Voltage Optimization program, stating it was "not convinced" that by implementing energy efficiency measures AIC would meet the Section 8-103(c) demand response requirements. For the purpose of projecting loads for this year's Plan, the IPA assumes that AIC will not deliver the required demand response reductions to the portfolio as in the 2009, 2010, and 2011 Plan years.

The IPA has included the impacts of the AIC energy efficiency programs based on its 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 for 2012 (159,162 MWh) for 2013 (134,341 MWh), for 2014 (130,399 MWh) for 2015 (127,850 MWh), and for 2016 (124,204 MWh).

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

V. PORTFOLIO DESIGN

Citing Section 16-111.5(d)(4) of the PUA, the IPA contends its priorities for the portfolio design are "to ensure adequate, reliable, affordable, efficient, and environmentally sustainable electric service at the lowest total cost over time, taking into account any benefits of price stability." The IPA indicates 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 elevating or lowering prices relative to the fixed price contracts secured through the IPA process. Risk is also defined as any change in the size of the load of eligible retail customers served through the IPA portfolio.

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 and distributed solar 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.

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., the 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.

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 for the purpose of protecting against price escalation.

Fuel costs, the IPA states, present risk to the portfolio insofar as fuel costs are the primary drivers of generation costs except for renewable resources like solar and wind. 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. Fortunately for consumers, the IPA says natural gas prices have been low and subdued over the past few years, resulting in lower marginal (and thereby futures) prices for electricity.

According to the IPA, part of the natural gas equation is the development of natural gas fracking methods. The IPA avers that potential regulation of the process may change the price dynamic for natural gas, and thereby electricity within the region. In September of 2010, the IPA reports that the Environmental Protection Agency ("EPA") took the first step in regulating natural gas hydraulic fracturing (“fracking”) by issuing a voluntary information request to fracking firms which requested disclosure of chemicals used in the fracking process. Although compliance is voluntary, the IPA says the EPA expects to use any information provided in its ongoing effort to study fracking by publishing a comprehensive study by late 2012.

The IPA reports that generally, the EPA has authority under the Safe Drinking Water Act (“SDWA”) to protect underground drinking wells; however, the Energy Policy Act of 2005 specifically exempted “the underground injection of fluids or propping agents (other than diesel fuels) pursuant to hydraulic fracturing operation related to oil, gas, or geothermal production activities” from regulation. The IPA says the proposed “Fracturing Responsibility and Awareness of Chemicals Act of 2011” attempts to remove this exemption, but it is currently receiving Committee attention in the House of Representatives. The IPA says that meanwhile, some states have attempted to limit the location of fracking operations through zoning regulations. However, state regulation of the ability of fracking operations to use undisclosed chemicals is specifically preempted by the SDWA. The IPA states that therefore, permits to start and maintain fracking operations continue to be approved by state regulators.

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

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, tariff rules, and the potential for cost sharing on super-regional transmission lines. The IPA says 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, for example, through investments in distributed resources. The IPA says, however, transmission cost allocation is a subject of federal regulation and any changes in transmission costs will likely be borne by all customers regardless of supplier.

The IPA goes on to discuss extensively, some of the issues under consideration by PJM, MISO, and the Federal Energy Regulatory Commission ("FERC"). These issues include the MISO Resource Adequacy Construct, the MISO proposal for dispatchable intermittent resources, and rules related to demand response compensation. Ultimately, the IPA concludes that it should continue to monitor the effect on prices for wholesale electricity in both interconnections, anticipating a slight increase in the PJM interconnection's price for demand response resources.

According to the IPA, market conditions generally relate to the drivers of market prices, customer usage, and customer switching levels. These variables are included in the statistical modeling conducted by the IPA relative to the portfolio design. The IPA says the current supply mix in Illinois has remained largely unchanged over the last decade, with the majority of the state's electricity generated by nuclear and coal fired plants located within the State. The IPA indicates that coal is the marginal fuel for most hours in the year, with wind depressing prices during some nighttime hours and natural gas setting prices during system peaks. Specific issues identified by the IPA that could impact market conditions include possible greenhouse gas regulations, clean air mercury rules, and carbon capture and sequestration regulations. The IPA suggests that it plans to continue monitoring potential rules and regulations that could have an impact on market conditions.

The IPA states that while no analysis can cover every possible risk, the IPA believes its analysis provides a reasonable representation of the significant risks associated with the June 2012 to May 2017 horizon. The IPA believes its Plan provides reasonable protection for customers from likely risk factors. As a result, given the guidance provided under the PUA, the IPA does not recommend an alternative to its recommended portfolio.

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.

The IPA says a model portfolio for each utility was developed and applied to each utility's respective load projections to illustrate the trade-offs between risks and benefits associated with different procurement approaches and ratios of forward and index purchases. 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 2014 as of August 12, 2011. The IPA views NYMEX as an appropriate indicator of future prices in the nearer term where market liquidity is sufficient to generate pricing competition. The IPA says that for periods after 2014, the monthly prices indicated on the NYMEX for those periods were escalated at 2% per year to account for market unknowns.

To test how each portfolio will perform under various market conditions, the 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 cannot 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 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 curve 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 in July 2011 and then manipulates 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, and (2) the amount hedged through the swap arrangements.

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 cannot 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, 2012 through May 31, 2015 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. Under Rider QF, 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

The IPA notes that ComEd and AIC entered into 20-year supply contracts with approved renewable energy generators in December 2010. The IPA indicates that the vast majority of these contracts were for wind generation assets. According to the IPA, those contracts secured energy supply as well as associated RECs with deliveries to commence on June 1, 2012. The IPA says the contract volumes in these contracts are arranged around an annual delivery volume with a plus or minus 10% volume allowance. The IPA further indicates that the contracts do not require minimum monthly deliveries, or peak and off-peak schedules.

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

1. Establishing reasonable monthly delivery volume projections based on historical regional averages.
2. Factoring those monthly delivery volume projections into peak and off-peak monthly delivery schedules.
3. Adjusting the peak and off-peak monthly delivery schedules into average MW contract volumes.
4. Including those averaged MW contract volumes into the utilities' procurement schedules.

The IPA accessed data from PJM that reported the wind generated power outputs in the ComEd region for the May 2009 through April 2011 period. The IPA says the monthly capacity factors were averaged to generate a generic May through April capacity factor schedule. From that schedule, the IPA indicates a generalized monthly volume allocation for wind outputs was established (in % of annual load). Then the IPA says ComEd's and AIC's long-term power purchase volumes were factored by the monthly percentages to establish a monthly renewable energy delivery volume. The IPA indicates those monthly renewable energy delivery volumes were then separated into peak and off-peak monthly allocations according to the averaged monthly peak and off peak allocations.

According to the IPA, the monthly peak and off-peak allocations (in megawatt-hours) were then divided by the number of peak and off-peak hours expected for each of the months included in this Plan to calculate a megawatt volume. These megawatt volumes will be deducted from the targeted contract volumes for each peak and off-peak period in each month between June 2012 and May 2017. In the Plan, the IPA provided tables intended to demonstrate the calculations described therein.

According to the IPA, energy required by ComEd's eligible retail customers comes from several sources. First, the swap contract with Exelon provides a financial hedge on 3,000 MW of around-the-clock ("ATC") energy during the June 2012 – May 2013 period. Second, certain fixed price physical supply contracts were secured through the 2010 procurement process. Third, as discussed above, the long-term renewable contracts that were entered into in December 2010 provide a financial hedge on 1,261,725 MWh a year for the period June 2012 through May 2032. Fourth, the IPA says it will solicit standard wholesale products through a sealed-bid RFP pursuant to the Plan approved in this proceeding. Fifth, the IPA states that balancing energy will be procured from the PJM-administered day-ahead and real-time energy markets.

With regard to the requirements of AIC's eligible retail customers, the IPA says energy and financial hedges come from six sources. First, the swap contract with

Ameren Energy Marketing provides a financial hedge on 1,000 MW of ATC energy during the June 2012 through December 2012 period. Second, financial hedges are in place for the period June 2012 through May 2013 with such hedges resulting from the 2010 procurement processes. Third, fixed price physical supply contracts for the period June 2012 through May 2014 resulted from the 2011 procurement process. Fourth, AIC will hedge price exposure for Residual Volumes (IPA will solicit standard wholesale products through a sealed-bid RFP per this Plan) using fixed price physical supply contracts. Fifth, long-term renewable contracts resulting from the 2010 procurement process are in place for both energy and RECs (20-year term). The volume associated with long-term renewable contracts are estimated and subtracted from the projections as discussed above. Sixth, AIC will procure the physical energy necessary to meet its combined load requirements via the MISO day ahead and real-time energy markets.

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

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

In determining the granularity of the standard wholesale products to be procured through the RFP, the IPA 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 2012 and May 2015, in whatever combinations are deemed appropriate by the Procurement Administrator, given the objectives described in the 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, megawatts covered by the previous RFPs and Exelon 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.

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.

ComEd Peak Load Volumes to be Secured in 2012 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	2012	1000	2013	650	2014	1200
July	2012	850	2013	900	2014	1550
August	2012	400	2013	750	2014	1400
September	2012	-50	2013	750	2014	1000
October	2012	0	2013	350	2014	750
November	2012	0	2013	450	2014	850

December	2012	300	2013	500	2014	1000
January	2013	450	2014	800	2015	1050
February	2013	-150	2014	550	2015	1000
March	2013	0	2014	500	2015	850
April	2013	0	2014	350	2015	700
May	2013	0	2014	400	2015	750

<u>ComEd Off-Peak Load Volumes to be Secured in 2012 Procurement Cycle by the IPA</u>

Month	Year	Amount to be Procured (MW)	Year	Amount to be Procured (MW)	Year	Amount to be Procured (MW)
June	2012	800	2013	850	2014	1050
July	2012	750	2013	750	2014	1300
August	2012	400	2013	700	2014	1200
September	2012	0	2013	750	2014	900
October	2012	0	2013	450	2014	750
November	2012	0	2013	550	2014	900
December	2012	100	2013	900	2014	1050
January	2013	200	2014	900	2015	1100
February	2013	0	2014	650	2015	1000
March	2013	0	2014	550	2015	950
April	2013	0	2014	500	2015	800
May	2013	0	2014	500	2015	800

<u>AIC Peak Load Volumes to be Secured in 2012 Procurement Cycle by the IPA</u>

Month	Year	Amount to be Procured (MW)	Year	Amount to be Procured (MW)	Year	Amount to be Procured (MW)
June	2012	550	2013	650	2013	650
July	2012	750	2013	900	2014	850
August	2012	650	2013	850	2014	800
September	2012	500	2013	600	2014	600
October	2012	350	2013	450	2014	450
November	2012	400	2013	550	2014	450
December	2012	600	2013	700	2014	650
January	2013	550	2014	700	2015	650
February	2013	500	2014	650	2015	600
March	2013	400	2014	500	2015	500
April	2013	250	2014	400	2015	400
May	2013	250	2014	350	2015	400

AIC Off-Peak Load Volumes to be Secured in 2012 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	2012	350	2013	550	2014	500
July	2012	500	2013	650	2014	650
August	2012	500	2013	600	2014	650
September	2012	250	2013	450	2014	500
October	2012	150	2013	350	2014	350
November	2012	250	2013	450	2014	400
December	2012	450	2013	600	2014	550
January	2013	900	2014	600	2015	600
February	2013	750	2014	550	2015	550
March	2013	350	2014	450	2015	400
April	2013	150	2014	300	2015	300
May	2013	200	2014	350	2015	350

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 Exelon 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 that the spring 2012 procurement event continue the process established in the spring 2011 procurement event whereby financial swaps were replaced with those that settle physically within MISO. The IPA believes this would appear to be the most prudent course of action until the rule making process is better understood. However, if the Procurement Administrator, after consultation with the IPA, utilities, Commission, and Procurement Monitor, determines that financial swap contracts are preferable to contracts for physical delivery of energy, the Procurement Administrator will be instructed to fashion the swap contract, as previously discussed. The IPA says it will monitor the rule making process and recommend a course of action for procurement events beyond spring 2012 as the outcome of the current rule making process becomes clearer.

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

The IPA 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 fixed price transactions that settle physically within MISO to balance its loads. The IPA claims this will act as a hedge for the energy price risk of the portfolio since 100% of the actual energy required to supply the load included in this Plan will be purchased in the MISO energy markets with such pricing varying from hour to hour. 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 adds that MISO charges, including Revenue Neutrality Uplift and Revenue Sufficiency Guarantee payments, will also apply.

B. Capacity Resources

According to the IPA, AIC and ComEd acquire capacity resources to meet MISO and PJM requirements tied to reliability. AIC and ComEd, the IPA states, are obligated by the MISO and PJM Tariffs to secure specific capacity resource volumes. The IPA indicates that PJM has created and maintains a forward market to set prices for capacity; securing capacity resources for ComEd load via this market tool is a means by which the resources can be secured at a competitive rate. The IPA indicates that MISO operates primarily on a bi-lateral contracting basis; therefore, the only option for AIC to purchase more than prompt monthly capacity is to conduct a procurement event.

Module E of MISO's Open Access Transmission, Energy and Operating Reserve Markets Tariff addresses resource adequacy, according to the IPA. 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. The IPA says 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 Planning Reserve Credits to meet or exceed its Resource Adequacy Requirement, the monthly peak load forecast plus its planning reserve margin.

The IPA indicates that in 2009, MISO implemented significant penalties associated with a capacity deficiency event based on the Cost of New Entry ("CONE"). For the 2009 planning year, the deficiency penalty was determined by MISO to be $80/kW-month, $90/kW-month for 2010 and $95/kW-month for 2011.

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

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

The tables below illustrate the IPA's proposal for AIC and were produced using information contained in the IPA's Plan. The capacity requirement values shown in the tables are the sum of peak load, transmission losses, and planning reserves, net of prior purchases.

Contract Month	Peak Load	Capacity Requirement	Proposed 2012 Purchases	Percentage Hedged
June 2012	3,675	2,461	2,470	100%
July 2012	4,139	2,823	2,830	100%
Aug 2012	4,181	2,908	2,910	100%
Sept 2012	3,573	2,382	2,390	100%
Oct 2012	2,490	1,723	1,730	100%
Nov 2012	2,314	1,556	1,560	100%
Dec 2012	2,781	1,752	1,760	100%
Jan 2013	2,949	1,950	1,950	100%
Feb 2013	2,702	1,788	1,790	100%
Mar 2013	2,225	1,412	1,420	101%
April 2013	2,056	1,372	1,380	101%
May 2013	2,619	1,840	1,840	100%

Contract Month	Peak Load	Capacity Requirement	Proposed 2012 Purchases	Percentage Hedged
June 2013	3,679	3,905	2,230	57%
July 2013	4,130	4,384	2,230	51%
Aug 2013	4,189	4,446	2,230	50%
Sept 2013	3,567	3,786	2,230	59%
Oct 2013	2,497	2,650	2,230	84%
Nov 2013	2,341	2,485	2,230	90%
Dec 2013	2,799	2,971	2,230	75%
Jan 2014	2,954	3,135	2,230	71%
Feb 2014	2,718	2,885	2,230	77%
Mar 2014	2,229	2,366	2,230	94%
April 2014	2,052	2,178	2,230	102%
May 2014	2,571	2,729	2,230	82%
June 2014	3,557	3,776	2,230	59%

July 2014	4,004	4,250	1,520	36%
Aug 2014	4,071	4,322	1,520	35%
Sept 2014	3,454	3,667	1,520	41%
Oct 2014	2,390	2,537	1,520	60%
Nov 2014	2,242	2,379	1,520	64%
Dec 2014	2,695	2,861	1,520	53%
Jan 2015	2,822	2,995	1,520	51%
Feb 2015	2,588	2,747	1,520	55%
Mar 2015	2,122	2,253	1,520	67%
April 2015	1,957	2,077	1,520	73%
May 2015	2,514	2,669	1,520	57%

The IPA indicates that ComEd will continue to procure the capacity and ancillary services required by the eligible retail customers directly from PJM-administered markets. Under the Reliability Pricing Model ("RPM") program approved by the FERC and administered by PJM, the IPA indicates ComEd is able to purchase capacity directly from PJM-administered markets. The IPA says the RPM capacity prices for the June 2012 to May 2015 period have already been determined through a competitive bid process administered by PJM, so direct procurement from PJM results in a reasonable approach to procuring capacity for these customers. Furthermore, the IPA believes the PJM-administered markets for ancillary services are the most visible and easily accessible markets for these services so direct procurement from these markets is a reasonable approach for providing these services to customers.

From time to time, the IPA says PJM may determine that the amount of capacity it procured three years prior to the delivery year exceeds the amount actually needed in the delivery year when adjusted for updated load forecasts. In such cases, PJM may return excess capacity credits to the utility. According to the IPA, these credits represent megawatt units of capacity and are not in the form of cash or cash equivalents. While these credits cannot be used to offset capacity payments to PJM, 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 indicates PJM has a bulletin board where such excess capacity credits can be made available for sale.

As discussed elsewhere in this Order, both AIC and ComEd filed motions to update their load forecasts which were granted. Additionally, as discussed later in this Order, the IPA has agreed and this Order requires the IPA to circulate its final Plan reflecting the conclusions in this Order to Staff within 30 days for its comments, and then file the Plan on e-Docket under Docket No. 11-0660 within 60 days, as well as on the IPA website. When those filings are made, the Commission directs the IPA to update the energy charts and capacity values for both AIC and ComEd.

C. Demand Response and Energy Efficiency

Section 8-103(c) of the PUA directs:

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

Additionally, the IPA notes that Section 16-111.5(b) of the PUA requires that the procurement plan shall include an analysis of the impact of demand side initiatives established by Section 8-103(b) and (c) of the PUA. The IPA says 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).

According to the IPA, ComEd's expected load model volumes are adjusted to account for energy efficiency program and demand response results. Additionally, the IPA says contract volumes attributable to long-term PPAs entered into by ComEd in December 2010 are factored out of the projection.

For the purpose of projecting loads for this year's Plan, the IPA assumes that ComEd intends to implement demand response programs sufficient to achieve its targeted peak reductions. Based on ComEd's analysis, and as discussed under the load forecast discussion in this Order, the effective aggregated reduction in ComEd's maximum system load requirements for eligible retail customers due to demand response programs is projected to be for 2012 (10.7 MW), for 2013 (10.8 MW), for 2014 (7.0 MW), for 2015 (7.0 MW), and for 2016 (7.1 MW).

Also discussed above in the load forecast portion of this Order, for the purpose of projecting loads for this year's Plan, the IPA assumes that AIC will not deliver the required demand response reductions to the portfolio as in the 2009, 2010, and 2011 plan years. The IPA has included the impacts of the AIC energy efficiency programs based on its 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 for 2012 (159,162 MWh), for 2013 (134,341 MWh), for 2014 (130,399 MWh) for 2015 (127,850 MWh), and for 2016 (124,204 MWh).

As discussed above in the capacity resource section of this Order, MISO operates primarily on a bi-lateral contracting basis and does not have a working capacity market. The Plan discusses at length, activities at FERC and MISO intended to develop a working capacity market. In the IPA's view, if MISO does establish a working capacity market, the resulting financial incentives to invest in demand response resources should create new products and increasing amounts of demand response activities aimed at lowering peak demand.

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 Resources 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 the information provided by the IPA is reproduced below.

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

In the IPA's view, it is important to note that the volume goals and cost caps for the IPA are variable. As retail competition develops in Illinois, the IPA expects that the RPS volume goals as the available budgets will diminish over time. In prior years, the RPS obligation was met through the purchase of RECs only. This approach proved sufficient to meet RPS volume goals while observing the statutory budget constraints.

The IPA notes that in December 2010, a series of 20-year Long-Term Power Purchase Agreements ("LTPPA") were entered. The LTPPAs specified a bundled purchase of energy plus RECs from renewable resources. Under these contracts, the IPA says a single price was set for the bundled product (energy plus REC) with a 2% per annum cost escalator over the term of the contracts. The cost of the energy included in the product was to be paid as a standard index energy contract, with the unit price set at variable market index. The cost of the REC was to be paid out of the Renewable Resources Budget ("RRB"), with the unit price set at the contract cost minus the variable market index energy cost.

Lastly, the IPA Act requires that 75% of the RPS be met with wind resources and eventually 6% by solar resources. The IPA says that recent solicitations for short-term wind RECs within the region indicate that market prices for those assets range around $1/REC. According to the IPA, solar RECs are less plentiful and thus more expensive than wind RECs; however, the costs of solar RECs in other states appear to be dropping.

The IPA asserts that meeting the RPS obligation is growing more complicated over time with volume requirements, budgets, and the costs of pre-existing contract obligations all operating in a variable manner. Additionally, because the forward cost curve governing the applied costs for RECs delivered under the LTPPAs is confidential, a final RRB for each utility cannot be presented. The IPA says the confidential forward price curve for energy is a critical component to establishing annual RRBs developed by the IPA, Procurement Administrators, Staff, and the Procurement Monitor to aid in establishing which portion of the annual RRB is to be allocated to the LTPPA contract costs. Therefore, the cost of the long-term obligations is not a known variable and is subject to change over time. The IPA observes that a comprehensive procurement system for renewables is necessary. The IPA claims the presence of the competing solar and wind carve-outs and their wide cost differences coupled with revenue variance increases the risk of the IPA portfolio not meeting its procurement goals in future years.

The IPA recommends the following method to be used to meet the RPS obligations for the 2012-2013 compliance year and beyond:

Establish a conservative Renewable Resources Budget for 20 years:

- Estimate the annual portfolio requirements for the next 20 years. Utilize forecasted sales for eligible retail customers consistent with the current utility low scenario projections to establish portfolio volumes for the first five years, then continue the average trend line for the first five years for all future years that are required. The result will be a portfolio volume that represents a high level of estimated consumer switching away from the IPA portfolio;
- Consistent with the PUA, apply the Rate Cap to the 20 year volumes calculated as above to establish annual RRBs for each year in the series;
- Apply the confidential future price curve generated by the IPA and submitted to the Commission to back out LTPPA cost obligations from the RRB to yield a Net Renewable Resources Budget ("NRRB") for each of the future years;
- Factor each annual NRRB by 50% and solicit RECs bids for up to the 20 years using the factored NRRB as a hard budget limit for all long-term renewable contracts.

Conduct procurements that yield carve-out consistent contracts for solar and wind:

- Invite bids for periods of up to 20 years from renewable generators (allow single year as well as multi-year bids for resources);
- Select only those bids such that all renewable contract volumes fit beneath the factored NRBB;
- Sort bids according to price and source (solar, wind, etc.);
- Select the lowest bid combination that yields at least the minimum carve out requirements when the LTPPA volumes are added to the new REC volumes;
- Conduct a procurement of distributed solar renewable energy credits ("SRECs") for no less than 25% of the solar renewable energy procurement obligation.

The IPA believes its proposed approach would facilitate offers from short-term REC bidders seeking contracts for low price RECs who would be more likely to bid into the near years of the 20 year period. The IPA suggests that longer term offers would be possible insofar as the costs of those bids coupled with existing LTPPAs do not over-obligate the RRB. The IPA suggests that bids would be evaluated and ranked according to Net Present Value ("NPV") with the IPA, the Procurement Administrators, Staff and the Procurement Monitor deriving an appropriate discount rate.

With regard to distributed SRECs, the IPA plans to design the procurement program for distributed SRECs between January and May 2012, announce the program in June 2012, and initiate the first procurement event by December 2012. The IPA says the procurement program will be designed to enable the utilities to sign long-term (at least 10-year) contracts for SRECs from distributed solar systems ("DG Solar") in Illinois at prices that are competitive with the average SREC clearing price from the procurement process described above.

The IPA plans to consider the following broad program types:

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

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

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

The IPA states that for purposes of the Plan, "distributed SREC" is intended to mean the renewable energy credit associated with the output of a solar photovoltaic system interconnected to the electric distribution system in Illinois and located on the customer's side of the electric meter.

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

The IPA notes 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 in the State of Illinois, then from facilities located in states adjacent to Illinois, then from facilities located elsewhere. Because renewable energy resources are being procured for a period after June 1, 2011, the State of Illinois preference no longer applies.

The IPA proposes that ComEd and AIC meet the renewable energy resource portfolio standard for the Plan year through the acquisition of qualifying RECs as defined in Section 1-10 of the IPA Act. The IPA believes the acquisition of RECs for this period meets the requirements of the IPA Act and is preferable to the direct acquisition of energy from qualifying renewable resources at this time.

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

The statute requires the higher of two separate calculations to establish each planning year's RERB. The IPA notes that certain renewable resources are already purchased under 20-year contracts and therefore the planning year RPS volume targets will be reduced and the result will be the quantity of one year RECs solicited in the Spring of 2012. The IPA also notes a change to the Procurement Plan for this year in that AIC and ComEd began collecting money from customers on their real time pricing tariffs starting June 1, 2010, pursuant to the legislative requirement. The legislation requires the IPA to increase its spending on the purchase of renewable energy resources to be procured by the electric utility for the next plan year by an amount equal to the amounts collected by the utility under the alternative compliance payment ("ACP") rate or rates in the prior year ending May 31. The IPA has therefore added this quantity to its RRB calculations. Additionally, the IPA also indicates that the Planning Year Projected Total Delivery Volumes reflect the aggregate projected portfolio minus losses.

The table below produced from information contained in the IPA Plan shows the renewable resource target volumes and the RRB limits under the two statutory calculations.

Renewable Resource Targets for 2012-2013
Annual Volume Targets and RRB Limits

	Planning Year RPS Volume Target (MWh)	Annual RRB Calculation Option A	Annual RRB Calculation Option B
ComEd	2,597,398	$ 2,988,205	$ 50,918,675
AIC	1,123,376	$ 1,263,352	$ 26,403,382

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

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.

The IPA also addresses the issue of material instances of supplier default on renewable energy contracts. The IPA proposes the following in the event that a utility's counterparty to a contract defaults and the default results in a reduction in the number of RECs retired on the utility's behalf for any given plan year ending May 31.

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

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

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

E. 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 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. According to the IPA, effective January 2009, MISO implemented an Ancillary Services market to provide regulation service and operating reserve service, both spinning and supplemental, reserves. The IPA says AIC procures these required services through the MISO Ancillary Services market.

With regard to 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 2011 ARR allocation process at MISO, AIC received a set of ARR entitlements and was awarded ARRs for the 2011 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.

F. 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. The IPA asserts that over the term of this Plan, the most significant driver of load shifting levels is customer switching. Prior to the procurement event, the IPA proposes for AIC and ComEd to true-up their forecasted amount of customer switching that is expected due to municipal aggregation programs. The IPA also proposes for AIC and ComEd to survey the actual number and size of the municipalities that have at that time filed with the relevant election authority to hold, or have already passed referenda, approving “opt out” aggregation. The IPA plans for AIC and ComEd to report the results to the IPA who will work with AIC, ComEd, Staff and the Procurement Administrator and Monitor to rebalance the portfolio commensurate with the change in forecasted customer switching due to municipal aggregation programs.

G. 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 PUA.

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. During the interim time period beginning at time of default and continuing through the contingency procurement process, all electric power and energy will be procured by the utility through PJM-administered markets. Notwithstanding, if a particular required product is not available through PJM, it shall be purchased in the wholesale market.

In the event of a supplier default that results in contract termination where the amount of load provided by that supplier is less than 200 MW or there are less than 60 calendar days remaining on the defaulted contract term, 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.

Should a procurement event be required subsequent to the initial event, the IPA intends for the Procurement Administrator and the Procurement Monitor to separately submit a confidential report to the Commission within two business days after opening the sealed bids. The IPA plans for the Procurement Administrator's report to put forth a recommendation for acceptance or rejection of bids based on the established benchmarks, as well as other observed factors, to include any modifications necessary to run a subsequent procurement event if necessary.

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

H. Clean Coal Resources

Section 1-75 of the IPA Act includes a requirement that annual procurement plans shall consider sourcing agreements covering electricity generated by power plants that were previously owned by Illinois utilities that have been or will be converted into clean coal facilities. Moreover, the IPA says it is the goal of the State that by January 1, 2025, 25% of the electricity used in the State shall be generated by cost-effective clean coal facilities. Further, under the IPA Act, the IPA's "procurement planning process" may propose to the IPA sourcing agreements "with utilities" required to comply with" 220 ILCS 5/16-115(5)(d).

Consistent with the statute, and to further demonstrate the viability of coal and advance environmental protection goals, the IPA indicates that it plans to seek proposals for both ComEd and AIC for up to 250 MW of electricity generated by advanced clean coal technologies that capture and sequester carbon dioxide emissions. The IPA says it will accept proposals from existing clean coal facilities, clean coal facilities that are under development, and qualifying coal-fired power plants previously owned by Illinois utilities that have been converted or will be converted into clean coal facilities. The IPA states that if a proposal is accepted and approved by the

Commission, the project sponsor and both ComEd and AIC will enter into long-term (20 years or greater) sourcing agreements. The IPA plans to seek proposals from entities that demonstrate that they have made significant progress to meeting a commercial in-service date of December 31, 2017. The IPA says that it and the Procurement Administrator will develop and apply benchmarks to evaluate any bid submission. The IPA identifies the criteria it plans to utilize to evaluate clean coal candidates prior to proposal submission.

I. Senate Bill 1652

The IPA notes that the Illinois General Assembly passed SB 1652 on August 26, 2011, and sent it to the Governor on August 29, 2011. Although the Governor vetoed that Bill on September 12, the IPA says legislative efforts to override that veto have been announced. If that bill becomes law, the IPA believes it could impact the amount of energy and RECs that is proposed to be procured in the Plan. The IPA says SB 1652 amends the PUA by adding subsection k-5 to Section 16-111.5. The IPA indicates that subsection requires the IPA to conduct a separate procurement event within 120 days of the effective date of the new law to procure both energy and RECs for the period June 1, 2013, through December 31, 2017.

The IPA states that the amount of energy that is to be procured is to be based upon an updated forecast of the minimum monthly load requirements shown in the forecasts. The amount of RECs that is to be procured is to be based on the amount of RECs that would satisfy the requirements set out in Section 1-75(c) of the IPA Act. According to the IPA, the exact timing of this separate procurement event is unknown, but should it occur prior to the procurement event implementing the Plan, the volumes of energy and RECs to be procured pursuant to the Plan would need to be revised downward in proportion to the amount of energy and RECs procured in the new procurement event. The IPA plans to work with Staff, the Procurement Administrator, the Procurement Monitor, and the utilities to revise the portfolio volumes if SB 1652 becomes law.

VII. DISPUTED ISSUES AND COMMISSION CONCLUSIONS

A. Clean Coal

1. ComEd's Position

ComEd supports the development of cost-effective renewables and clean coal technologies. ComEd does not, however, believe that promoting clean coal means committing significant amounts of customers’ money to proposals that are uneconomic. In ComEd's view, by pushing to acquire clean coal through an incomplete proposal that omits critical terms and lacks safeguards assuring customers of least-cost energy over time, the Plan will not support the development of clean coal in a legal, appropriate, and efficient manner.

ComEd argues that the IPA Act and PUA correctly recognize the importance of protecting customers by requiring the Plan to procure energy at the "lowest total cost over time." ComEd says in the case of future clean coal technology, the IPA Act also recognizes it by requiring the IPA to include electricity generated from clean coal facilities in a procurement plan only at such time as the utilities are required to enter into sourcing agreements with the initial clean coal facility. According to ComEd, because no such entity or agreements exist at this time, it is neither necessary nor appropriate to include this proposal in the current Plan.

ComEd believes the IPA can propose a procurement plan that includes the purchase of electricity from clean coal facilities other than the initial clean coal facility, but only where that purchase meets the law's other requirements. In ComEd's view, such a proposal is also subject to Commission approval under the PUA's standards and customer protections. Here, however, ComEd claims the IPA provides no discussion, nor the evidence, that is required demonstrating how purchasing capacity from a hypothetical clean coal facility in 2012 meets the PUA's "lowest total cost over time" standard. ComEd believes this is understandable given that, at present, such facilities are among the most expensive sources of energy and the recent analysis and report sponsored by the Commission regarding Tenaska's proposed Taylorville Energy Center ("TEC").

Finally, ComEd contends the Plan's proposal is unreasonable because it would impose the cost of clean coal solely on the utilities' eligible retail customers. In ComEd's view, this is highly unfair and inconsistent with the IPA Act, which provides for any such costs to be borne by all customers, including ARES' customers. In addition, given the extreme uncertainty of ComEd's future load, ComEd claims the procurement of additional resources on a long-term basis is not a prudent proposal at this time.

In its Response to Objections, ComEd describes FutureGen's statement that "Section 75 of the Illinois Power Agency Act includes a requirement that annual procurement plans include electricity generated by clean coal facilities" as overbroad and claims it mischaracterizes the law. ComEd maintains that while the IPA Act calls on a procurement plan to include electricity generated by a clean coal facility, it does so only in the context of requiring utilities to acquire energy through a sourcing agreement with an initial clean coal facility in specific limited circumstances and subject to consumer protections. ComEd insists that since the statutory conditions triggering the obligation to enter into a sourcing agreement with an initial clean coal facility have not occurred, there is no current "requirement" to include electricity generated by clean coal facilities in the Plan. According to ComEd, FutureGen also fails to take into account that previous procurement plans did not provide for procurement of electricity generated by clean coal, confirming that the IPA, the Commission and all parties have not interpreted the IPA Act's provisions to require the procurement of clean coal electricity at this time.

ComEd contends that FutureGen fails to mention that no sourcing agreements were provided by qualifying clean coal facilities during the procurement planning process. In ComEd's view, the clean coal proposal is premature at best and the statutory references to the IPA Act's retrofit clean coal provisions do not provide support for the instant proposal.

ComEd argues that the interest of a single bidder does nothing to meet the requirements under the IPA Act. ComEd maintains that this proposal is not consistent with Section 1-75(d)(5) of the IPA Act which requires clean coal facilities to present sourcing agreements for consideration during the procurement planning process. ComEd claims this has not occurred and the absence at this time of other interested projects cautions against the clean coal proposal because the benefits and protections of a competitive procurement process would be at risk under a single-bidder procurement. According to ComEd, this concern underscores the IPA Act's requirement that the IPA and the Commission consider the procurement of energy from a retrofitted clean coal facility only at such time as they are presented with sourcing agreements specifying all the proposed terms and conditions of service. ComEd also asserts that the IPA's discretionary authority to include the procurement of electricity generated by clean coal facilities must meet other applicable requirements, including the requirement to ensure adequate, reliable, affordable, efficient, and environmentally sustainable electric service at the lowest total cost over time. ComEd insists there has been no showing that this standard is likely to be met, and available data indicates otherwise.

On the first point, while a FutureGen plant may provide capacity in the market, ComEd contends that so will any generation plant or demand response initiative. ComEd maintains that when using its discretionary authority to include a clean coal provision, the IPA must select a portfolio that achieves the lowest total cost over time. Referring to Dr. Tolley's Affidavit, ComEd insists there are far less expensive forms of capacity and energy which preclude clean coal from meeting this criterion. As to the argument regarding the Clean Coal Portfolio Standard, ComEd asserts there is no current clean coal requirement and the clean coal energy "goal" is just that, a discretionary goal. Finally, ComEd claims FutureGen has misstated the law regarding price stability. ComEd says the reference in Section 1-5(1) of the IPA Act, repeated in Section 16-111.5(d)(4) of the PUA as a substantive requirement for approval of a procurement plan, is to "adequate, reliable, affordable, efficient, and environmentally sustainable electric service at the lowest total cost over time, taking into account any benefits of price stability." According to ComEd, there is no specific directive in the IPA Act or PUA to administer power procurements "so as to best achieve price stability." Rather, price stability is to be taken into account when applying the "adequate, reliable, affordable, efficient, and environmentally sustainable electric service at the lowest total cost over time" standard.

In its Reply to Responses, ComEd notes the only party filing a response supporting the now-superseded original clean coal proposal was FutureGen. ComEd asserts that response lacks merit. ComEd explains why it believes there is no current requirement for the Plan to include electricity generated by clean coal. ComEd also explains its view that the IPA's original clean coal proposal was required to meet the lowest total cost over time requirement. ComEd also maintains that the IPA's original clean coal proposal did not include sufficient details.

2. Staff's Position

While Section 1-75(d)(1) of the IPA Act provides that “procurement plans shall include electricity generated using clean coal,” and proclaims the State's goal that “by January 1, 2025, 25% of the electricity used in the State shall be generated by cost-effective clean coal facilities,” Staff believes the Commission is not obligated to approve any purchases from clean coal facilities other than those associated with the “initial clean coal facility,” as defined in Section 1-75(d)(3). Staff also asserts that while Section 1-75(d)(2) of the IPA Act prohibits purchases of clean coal facility output beyond a level at which rates for eligible retail customers increase by more than certain prescribed percentages (similar to purchases of renewable energy resources), this does not mean that the Commission cannot set a more stringent standard (except in the case of the “initial clean coal facility”). Given the expense of generating electricity with clean coal technologies relative to that of natural gas technologies, Staff believes it is unlikely that a solicitation of proposals for 20-year contracts with a clean coal facility will be in the financial interest of Illinois consumers.

Staff says that although the Plan is unclear on this point, Staff is concerned that the IPA intends to charge the utilities (and hence ratepayers) for the expenses associated with its solicitation of proposals for 20-year contracts with a clean coal facility. Staff is concerned because such a solicitation could be extremely costly as well as unlikely to result in a contract beneficial for Illinois consumers.

Staff is also concerned that the IPA will be over-extending itself by engaging in another potentially complicated procurement process at the same time that it is proposing to conduct both workshops and two other new procurement processes for SREC from owners and aggregators of distributed solar photo-voltaic resources, and at the same time it is being required by law to expand its activities into arranging contracts between the State's gas utilities and both a "clean coal SNG [substitute natural gas] brownfield facility" and a “clean coal SNG facility.”

Staff opposes the IPA's proposal to solicit clean coal facility proposals, with the intent of requiring ComEd and AIC to enter into long-term contracts with one or more suppliers. Staff recommends that the Clean Coal Energy proposal be deleted from the Plan.

In its Response to Replies, Staff says there is no indication that the contract terms specified in Appendix K would satisfy clean coal resource suppliers or adequately protect ratepayers, let alone balance those competing interests in a manner that minimizes costs for ratepayers. Staff also believes there is no indication Appendix K is the “gold standard” for long-term renewable procurements. Staff asserts that to the contrary, the procurement process described in Appendix K required further workshops after posting the “final” contracts in order to address numerous concerns relating to the pre-bid security, collateral requirements, and various other long-term renewable contract terms that Appendix K specified, but which suppliers found objectionable. According to Staff, if the Commission were to desire workshops to be held on a clean coal procurement process, Staff would favor a more organic approach to this novel procurement, meaning one in which stakeholders could identify the issues and vet their concerns with a clean coal resources procurement, without any of Appendix K's constraints. Staff still opposes the inclusion in the Plan of clean coal procurement.

3. RESA's Position

RESA notes that the 2012 Plan includes a proposal to procure up to 250 MW of electricity generated by a clean coal facility, on the basis that this is required by the IPA Act. According to RESA, the basis for the IPA's proposal is incorrect because the procurement of clean coal is not required by the IPA Act. RESA contends that the requirement in the IPA Act exists only at the time when the utilities enter into sourcing agreements with the initial clean coal facility. RESA says no party asserts that such a clean coal facility exists. In RESA's view, the IPA has no basis to subject the utilities' eligible customers to exorbitant increased costs, and even greater costs risks for the customers of RESs.

Because there is no requirement to include clean coal in the 2012 Plan, RESA claims the IPA can only do so if the clean coal procurement 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." RESA believes the IPA's proposal to procure energy on a long-term basis from clean coal facilities would not result in the lowest cost over time for electric service. RESA asserts that the cost of such energy is higher than the cost of energy generated from other types of generation facilities. RESA says the cost study filed by the Commission related to the Taylorville Facility showed costs more than $8 billion above market over the next 30 years. RESA also contends there are many issues associated with long-term contracts, in general, which involve costs and risks to customers, which the IPA has not addressed. RESA says long-term contracts pose challenges in today's wholesale markets. RESA suggests that wholesale markets for electricity products with longer delivery periods are less liquid, and the lack of transparent market prices at this time for longer-term delivery periods adds additional uncertainty for bidders in developing bids, for regulators in evaluating bids, and for default service providers in developing collateral requirements to protect customers from financial exposure associated with supplier default. RESA also complains that the 2012 Plan leaves many important details relating to clean coal procurement unstated and related issues unresolved.

In its Reply to Responses, RESA says that while FutureGen's position is understandable from the perspective of a company that desires to be the initial clean coal facility, RESA agrees with the IPA that it is best to defer this issue until a future Plan and that it makes sense for the IPA to work through clean coal procurement issues with interested parties through a workshop process when the time is appropriate.

4. Constellation's Position

In Constellation's view, there is little justification for a clean coal component of this year's Plan, which constitutes a major change from prior Plans. Constellation also complains that few details are provided for the planned solicitation itself, or what is to occur after the solicitation.

Constellation argues that a thorough reading of Section 1-75 of the IPA Act reveals no such requirement; rather, the IPA Act's directive that the IPA encourage the development of coal resources and is limited to the issuance of bonds financed by the Illinois Finance Authority, not with regard to procurement plans.

In Constellation's view it is unclear why it is necessary or prudent to seek solicitations for long-term contracts more than a decade earlier than any such requirement. Constellation suggests that when federal funding is so readily available, whether or not long-term contracts such as contemplated under the Plan exist is irrelevant to whether or not such facilities will ultimately be built. According to Constellation, the Plan implicitly recognizes that long-term contracts under the Plan are not necessary for the development of “clean coal” facilities. Constellation suggests this can be seen from the fact that the Plan requires that, as a condition of eligibility, the project sponsors “[d]emonstrate a viable plan for securing all of the necessary capital required to support the development, engineering, construction and startup and commissioning of the clean coal facility.” Constellation claims the benefits and realities of “clean coal” have yet to be thoroughly explored. Constellation asserts that cost estimates for these technologies have skyrocketed, even before construction. According to Constellation, whether such facilities will even be built remains to be seen. Constellation believes it would be prudent to hold off on any solicitation for the procurement period being contemplated under this Plan.

Constellation complains that it is not clear how or why the IPA arrived at a desired amount of 250 MW. Nor is it clear to Constellation whether the 250 MW is per utility or in the aggregate and, if the latter, what the allocation of the megawatts procured would be between the utilities.

Constellation says it is also not clear what the planned procurement period would be, though one may assume that the requirement for a commercial in-service date of December 31, 2017, contemplates a delivery period beginning in 2018, at the earliest. Constellation also claims there are (and may likely be) few qualifying facilities. According to Constellation, the Plan does not provide any indication that one may expect any qualifying bidders. Given the dearth of such facilities, not to mention the lack of any organized markets with meaningful long-range forecasts to support this portion of the Plan, Constellation claims it may be impossible to determine what constitutes a cost-effective resource. Constellation claims there is no objective criteria identified in the Plan, nor even a methodology and process by which any responses to the solicitation are to be weighed. In Constellation's view, there is simply not enough information included in the Plan to be able to meaningfully consider such a product, even if the underlying assumptions of the Plan were correct.

5. AIC's Position

AIC indicates that it supports continued discussions of clean coal purchases among various parties; however, AIC believes the IPA proposal is deficient in a number of respects. The recommendation lacks detail regarding the quantity, associated term and type of products sought. AIC says it is unclear if we are to assume that the solicitation will be for energy only, energy and capacity, or energy, capacity and associated environmental credits. AIC claims it is also unclear if we should assume that the solicitation will be for block purchases or a quantity tied to the output of the facility and if tied to the output of the facility, the minimum output is not defined. AIC believes this lack of detail conflicts with Section 16-111.5(b)(3)(iv) of the PUA which requires that specific terms and quantities be provided in the Plan.

AIC says the Clean Coal Portfolio Standard assumes that each utility would purchase supply from the initial clean coal facility by 2015. AIC notes sourcing agreements associated with the initial clean coal facility have not been executed and therefore it assumes that the IPA is proposing purchases other than the initial clean coal facility.

According to AIC, the Clean Coal Portfolio Standard further states a goal that 25% of the electricity used in Illinois shall be generated by cost-effective clean coal facilities by 2025. AIC states that while the Clean Coal Portfolio Standard appears to allow the IPA to propose solicitations other than the initial clean coal facility, such solicitations are arguably optional. AIC suggests the Commission could apply more stringent criteria for its benchmarks, up to and including evaluation using least cost principles.

AIC recommends that if the IPA desires to pursue a solicitation for clean coal facilities in its Plan, the IPA should be directed to provide specifics regarding which products will be solicited, for what term, in what quantity, how the cap and other cost benchmarks apply and what role the Commission has in reviewing and approving the results of such a solicitation. AIC believes that without these specifics, the IPA proposal for clean coal facilities should be removed from the Plan.

6. ICEA's Position

ICEA argues that contrary to the IPA's assertions, the procurement of clean coal is not required by the IPA Act. ICEA says the requirement exists only when and at such time as the utilities enter into sourcing agreements with the “initial clean coal facility,” which is a defined term under the IPA Act. According to ICEA, this conclusion is supported by the fact the IPA did not include clean coal in its two prior procurement plans, despite the fact that the clean coal portfolio standard provisions in the IPA Act were effective at those times. ICEA notes that no parties in those earlier procurement plan proceedings before the Commission raised any clean coal issues, nor did the Commission itself raise or address the same issues in its Orders approving the plans. ICEA claims no party does or can assert that such an “initial clean coal facility” exists. Without any such facility or a resulting statutory obligation to include clean coal in the procurement Plan, ICEA believes the IPA has no basis to subject eligible customers to the exorbitant increased costs, and impose even greater cost risk on ARES’ customers.

ICEA contends that since there is no requirement to include clean coal in the procurement, the IPA can only do so provided 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.” In ICEA's view there can be no credible argument made by any party that electricity from a clean coal facility meets the “lowest total cost” requirement of the PUA, and indeed, in its draft plan, the IPA did not even try. Because no clean coal facility currently exists, ICEA believes it is unclear how the IPA would even establish the required benchmark. ICEA says the cost study filed at the Commission by the Taylorville Facility showed costs more than $8 billion above market over the next 30 years and serves as proof that the “lowest cost over time” requirement cannot be met by any plan that proposes to include the procurement of power from clean coal facilities.

According to ICEA, because the clean coal portfolio standard applies a cost cap for clean coal procurement on the eligible customers, but applies none for the ARES’ customers, the IPA’s proposal places even greater risk on the latter. ICEA claims it is unlikely that 250 MW of electricity from clean coal – because of its significantly above-market costs – could be procured over the next 20 years by eligible customers alone because of the statutory cost cap. ICEA says this is especially true given the recent positive developments in retail competition and potential for significantly increased shopping by residential customers over those years. Given the existing language of the clean coal portfolio standard and failure of the legislation to provide any protection to ARES’ customers, ICEA insists there is a significant risk that ARES’ customers will be called upon to help fund the clean coal contracts that the eligible customers cannot. Accordingly, ICEA urges the IPA to eliminate the costly, unnecessary, and unsupported proposal to procure electricity from a clean coal facility.

In its Response to Objections, ICEA states that since there is no requirement to include clean coal in the procurement, the IPA can only do so provided 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.” ICEA claims there has been no credible argument made by any party that electricity from a clean coal facility meets the “lowest total cost” requirement of the PUA, and indeed, in its draft Plan, the IPA did not even try. ICEA claims the only party who supported the clean coal procurement in its Objections likewise was unable to provide any evidence to support this requirement.

7. Exelon's Position

Exelon states that the Clean Coal Portfolio Standards were added to the IPA Act by Public Act 95-102 in 2009. The IPA Act does state that "procurement plans shall include electricity generated using clean coal." According to Exelon, context indicates that the Illinois General Assembly intended to make this requirement contingent upon a utility entering into a sourcing agreement with the "initial clean coal facility," which is why the General Assembly also required the sourcing agreement to be included in the procurement Plan. Exelon notes that there is no existing initial clean coal facility. Exelon argues that without an existing initial clean coal facility, the IPA is not required to include the requirement to procure electricity generated by a clean coal facility. Exelon says this conclusion has been reached by all parties, including the IPA and the Commission, in the previous two procurement Plans since the amendments became effective. Exelon notes that in its previous Plans, the IPA has not interpreted the IPA Act to require similar clean coal provisions, nor did the Commission itself address clean coal issues in the previous proceedings.

According to Exelon, in the Plan, the IPA merely proposes clean coal procurement but provides no evidence to demonstrate how the proposal meets the PUA's requirements. Exelon insists that because no clean coal facility currently exists, and the technology itself is unproven, there has been no showing that the costs to retail customers will meet the "lowest total cost over time" standard. Exelon claims the Commission's recent analysis of the Tenaska Clean Coal Facility strongly supports the conclusion that the least cost standard cannot be satisfied, finding the costs of such a facility to be "substantially higher" than for other types of generation facilities.

8. FutureGen's Position

FutureGen supports the Plan's provisions pertaining to clean coal resources, which FutureGen supports; however, FutureGen offers what it describes as some minor objections and recommendations designed to improve the efficacy of the clean coal procurement.

FutureGen recommends the Commission revise Section 4.1 of the Plan to clarify the reference to clean coal projects proposed from power plants previously owned by Illinois utilities to the following:

> Section 1-75(d) of the IPA Act includes a requirement that annual procurement plans shall consider sourcing agreements covering electricity generated by power plans that were previously owned by Illinois utilities and that have been or will be converted into clean coal facilities (referred to as "Retrofitted Clean Coal Sourcing Agreements") <u>and that the contract price for electricity sales shall be established on a cost of service basis.</u>

FutureGen believes that this change is consistent with the language of Section 1-75(d)(5) regarding the repowering and retrofitting of power plants previously owned by Illinois utilities to qualify as clean coal facilities.

FutureGen also would recommend that the Commission modify the general specification for carbon dioxide ("$C0_2$") Storage Rights to the following:

> Demonstrate substantial progress toward obtaining executed option agreement(s) or ownership of sufficient pore space in the Mount Simon deep saline geologic storage formation to support at least 20 years of $C0_2$ storage or for the duration of the proposed Power Purchase Agreement, whichever is greater.

FutureGen believes that this change is appropriate given the sequential nature of the development process for a large multi-faceted project and that all of the necessary properties rights will be required to support financing for a clean coal project.

Finally, FutureGen would recommend that the Commission modify the general specification for Prevention of Significant Deterioration ("PSD") (Air) Permit to the following:

> Demonstrate that a PSD (Air) Permit, if required, has either been issued, or an application has been filed with the Illinois EPA.

FutureGen believes this change is appropriate because it is possible that a clean coal project may not be required to obtain a PSD permit given the near-zero level sulfur dioxide ("$S0_2$"), nitrogen dioxide ("$N0_2$"), and carbon monoxide ("CO") emissions generated by such a project.

In its Response to Objections, FutureGen says, ComEd cites subsection (d)(1) of Section 1-75 of the IPA Act. FutureGen asserts that not only does that provision include language directly requiring clean coal in annual power procurement plans, no where does that provision state that a clean coal procurement is contingent upon the construction of the initial clean coal facility. FutureGen says the provision does state that a utility will be deemed to have complied with the requirements of the Clean Coal Portfolio Standard if it enters into adequate sourcing agreements with the initial clean coal facility; however, it defies the imagination to suggest that this compliance provision is tantamount to the assertion that a clean coal facility must be constructed to trigger the Clean Coal Portfolio Standard.

According to FutureGen, the fundamental argument of those opposed to including clean coal in the 2012 Plan is that the initial clean coal facility must serve as a “trigger” before the Clean Coal Portfolio Standard kicks in. FutureGen believes the problem with that assertion is that it is not supported by Illinois law. FutureGen contends that other provisions in the IPA Act and the PUA the assertion that construction and/or operation of the initial clean coal facility is necessary to activate the provisions of the Clean Coal Portfolio Standard. FutureGen specifically cites Section 16-115 of the PUA.

FutureGen argues that by expressly referencing other clean coal facilities, Section 16-115 of the PUA clearly contemplates other clean coal facilities in addition to the initial clean coal facility. FutureGen also claims the repowering and retrofit provision of the IPA Act expressly states that the IPA, during the procurement process, shall consider sourcing agreements "covering electricity generated by power plants that were previously owned by Illinois utilities and that have been or will be converted into clean coal facilities . . . ." In addition, FutureGen says the IPA Act expressly states that it is the goal of the State that by January 1, 2025, 25% of the electricity used in the State shall be generated by cost-effective clean coal facilities.

FutureGen believes that taken together, these provisions conclusively demonstrate that the General Assembly contemplated more than just the initial clean coal facility when it approved the provisions. FutureGen says that focusing solely on the initial clean coal facility renders the title of subsection (d) of Section 1-75 of the IPA Act, "Clean Coal Portfolio Standard," as well as the 25% clean coal goal, meaningless.

FutureGen suggests that because some parties can locate no basis for their arguments in the IPA Act or PUA, they make unsubstantiated assertions that the clean coal procurement is "unsupported" or that it is the parties' "understanding" that the initial clean coal plant is a "trigger" for the clean coal portfolio standard. FutureGen claims that general "understandings" and "interpretations" of the IPA Act cannot contravene the clear language of the Act. FutureGen says other parties only refer to previous IPA procurement Plans. FutureGen asserts that past practices prove nothing – the IPA's failure to include clean coal in previous Plans does not negate the statutory language or statutory requirements. FutureGen also says those parties do not reference any legislative history to support their assertions about parties' "understandings" and "interpretations," likely because the legislative history of the bills which created and amended the Clean Coal Portfolio Standard provides no evidence that the initial clean coal facility was required before the IPA could procure power from other clean coal facilities.

FutureGen also disputes the argument that the PUA requires that clean coal procurement can only be done if it provides the lowest-cost power. FutureGen says that asserting that the IPA must procure clean coal power on a lowest-cost basis ignores the fundamental premise and purpose of the Clean Coal Portfolio Standard. FutureGen states that like the provisions in Illinois' RPS, which reside in the preceding subsection of Section 1-75 of the IPA Act, Illinois' Clean Coal Portfolio Standard contemplates a separate power procurement event for clean coal than for other power. FutureGen claims that through cost caps and benchmarks, the IPA Act establishes a framework to ensure that clean coal is procured in the most efficient and least expensive way.

FutureGen disputes the conclusion that clean coal resources are prohibitively expensive when compared to other new generation technologies. FutureGen claims there are numerous differences between FutureGen 2.0 and the TEC.

FutureGen claims the U.S. Department of Energy (“DOE”) is contributing over $1.0 billion dollars to FutureGen 2.0 to reduce the need for funds from the financial markets and industry participants. FutureGen says this significant capital contribution will help lower the fixed costs associated with the project. Future states that also reducing the fixed costs for FutureGen 2.0 is that the non-profit FutureGen is supporting the storage and pipelined portion of the project. Because of the non-profit status of FutureGen, it claims no rate of return on the industry funded portion of the capital will be required.

According to FutureGen, FutureGen 2.0 will also not be relying on pipeline natural gas to generate a significant portion of the electricity from the project. FutureGen says in the Commission's review of the TEC it was clear that nearly half of the proposed generating capacity is to be fueled using natural gas. FutureGen claims stability in prices of fuel to generate electricity is important to electricity price stability. FutureGen also asserts that historically, prices of natural gas have been extremely volatile and are expected to increase in price at a rate four times greater than coal and FutureGen 2.0 will use coal as its only fuel source.

FutureGen alleges that repowering existing coal power plants as proposed by FutureGen 2.0 has other advantages when compared to greenfield development of clean coal resources like the TEC. For instance, FutureGen says the Meredosia site already has sufficient transmission capacity to export all of the electricity produced to the high voltage transmission network, thereby eliminating the need for costly system upgrades. FutureGen adds that the Meredosia site also offers benefit of reusing other balance of plant system already in place because of the existing coal power plant operations.

FutureGen dismisses concerns about the lack of details surrounding the proposed procurement process for clean coal resources and the importance of protecting ratepayers. While FutureGen agrees with some of the points raised, FutureGen claims it is up to the IPA to ensure that any procurement event be conducted in a transparent manner, consistent with principles already approved by the Commission, and provide for ratepayer protections. FutureGen says the IPA has already defined and the Commission approved how a procurement process for new long-dated resources should be conducted when it approved the IPA’s supplemental filing on November 9, 2009 (referred to as Appendix K), in the 2010 procurement Plan for long-term renewable resources.

FutureGen states that the procurement process outlined in Appendix K clearly defines how the IPA can solicit potential long-term resources and the FutureGen Alliance believes that a similar approach, using many of the same elements, is appropriate for the procurement of clean coal resources. FutureGen believes that any procurement process must include a pre-qualification step focusing on appropriate development milestones. FutureGen suggests the IPA has already provided criteria in Table FF "General Specifications for Clean Coal Candidates" of the Plan which provides a means to qualify proposed clean coal projects. FutureGen believes the use of a stand-alone competitive RFP designed and conducted in accordance with Section 16-111.5 of the PUA and Section 1-75 of the IPA Act under is also recommended and supported by previous Commission Orders.

FutureGen argues that in the IPA Act, with its inclusion of clean coal resources in the Plan and the creation of a Clean Coal Portfolio Standard with a goal of 25% of generation from clean coal resources, the General Assembly envisioned a prominent role for the use of advanced coal technologies to generate electricity in Illinois. FutureGen claims that facing a number of new EPA rulemakings that require costly retrofit investments (e.g., the Cross State Air Pollution Rule, the proposed National Emission Standards for Hazardous Air Pollutants From Coal and Oil-Fired Electric Utility Steam Generating Units (Utility Maximum Achievable Control Technology), proposed Standards for Cooling Water Intake Structures at Existing Facilities and Phase I Facilities, and the proposed Disposal of Coal Combustion Residuals from Electric Utilities Rule), a substantial amount of coal-fired generating capacity will retire.

According to FutureGen, the installed electric power sector coal-fired capacity in the U.S. is 310 gigawatts ("GW"). FutureGen says Illinois is estimated to lose at least 9% (4 GW) of its coal-fired capacity due to the EPA rules by 2018. FutureGen believes the procurement of up to 250 MW of advanced clean coal resources will help maintain generation resource diversity in Illinois, create new base load capacity in Illinois, and help satisfy the Clean Coal Portfolio Standard.

In its Reply to Responses, FutureGen indicates it is disappointed that the IPA elected to remove the clean coal procurement in the Plan after objections to it were raised by certain parties, particularly before all parties in this proceeding had a chance to submit responses to those objections and replies to those responses.

FutureGen states that after tacitly conceding that future coal-fired power plant retirements are a reality, ComEd asserts that a clean coal procurement is not necessary because any form of new generation will help satisfy power demand. FutureGen contends that this assertion ignores the fundamental purpose of the Clean Coal Portfolio Standard and renders its application meaningless. FutureGen maintains that like the provisions in Illinois' RPS, which reside in the preceding subsection of Section 1-75 of the IPA Act, Illinois' Clean Coal Portfolio Standard contemplates a separate power procurement event for clean coal than for other power. FutureGen says that through cost caps and benchmarks, the IPA Act establishes a framework to ensure that clean coal is procured in the most efficient and least expensive way.

FutureGen suggests ComEd does not possess knowledge of future power prices and costs for new generation that goes beyond what the rest of the market knows. According to FutureGen, the central purpose of a clean coal procurement event would be to determine whether clean coal can be obtained in a cost-effective manner consistent with the IPA and the PUA. FutureGen says the Commission would then evaluate any clean coal sourcing agreements to determine whether the development of new clean coal resources is cost-effective and beneficial to ratepayers. Without a clean coal procurement event, FutureGen claims the IPA and Commission will never know whether clean coal power would be cost-effective and beneficial to ratepayers. FutureGen contends that for these practical, market-based reasons as well, it is prudent for the IPA to propose a clean coal procurement.

9. IPA's Position

The IPA rejects the claims that the IPA Act and the PUA do not authorize the Commission to include a plan to procure energy from a clean coal retrofitted facility. Section 1-75(d)(5) provides that the 2009 procurement planning process for ComEd and AIC, "and thereafter," shall consider sourcing agreements covering electricity generated by power plans that were previously owned by Illinois utilities and that have been or will be converted into clean coal facilities (referred to as "retrofitted clean coal" sourcing agreements). Section 1-75(a)(1) of the IPA Act further provides that the IPA's procurement plans "shall include electricity generated using clean coal."

Section 1-75 also provides that "[e]ach utility shall enter into one or more sourcing agreements with the initial clean coal facility . . . ." According to the IPA, the sourcing agreements between the utilities and the initial clean coal facility will not become effective until the General Assembly enacts authorizing legislation approving the price to be charged for the electricity, and fixes the rate of return for the project. The IPA believes Section 1-75 of the IPA Act makes a clear distinction between initial clean coal facilities and retrofitted Clean Coal Facilities. The IPA states that the pricing formula of the initial clean coal facility is different than the pricing standard to be applied to bids submitted by retrofitted clean coal facilities. In addition, the IPA says utilities and ARES are required to enter into contracts with the initial clean coal facility for up to 5% of the total supply required to serve the load of eligible retail customers in 2015 (ARES are also required to contract with the Initial Clean Coal Facility, but at a different volume standard, see 220 ILCS 5/16-115(d)(5)(iv).) The IPA states that utilities and ARES are not required to enter into contracts with a retrofitted clean coal facility. The IPA believes it is notable that neither the IPA Act, nor the PUA requires that each utility enter into a sourcing agreement with a retrofitted clean coal facility after the sourcing agreements with the clean coal facility authorized by the General Assembly.

The IPA believes the IPA Act mandates that annual procurement plans consider sourcing agreements covering the procurement of cost-effective electricity generated by clean-coal facilities. However, the IPA is persuaded by the comments and objections that it is not necessary to include this provision in the 2012 Plan. Specifically, the IPA suggests replacing Section 4.1 with the language offered by ComEd, with an additional edit to better reflect the proposed modification.

To be clear, the IPA says the proposal to procure energy from cost-effective clean-coal facilities will be considered in future Plans. The IPA looks forward to working through clean coal procurement issues with interested parties via a workshop process when the time is appropriate.

In its Reply to Responses, the IPA maintains its position that the Plan would permit further study of the issue by conducting workshops prior to actually conducting a procurement event for clean coal. According to the IPA, FutureGen correctly asserts that Section 1-75(d)(5) of the IPA Act provides that the 2009 procurement planning process for ComEd and AIC, "and thereafter," shall consider sourcing agreements covering electricity generated by power plants that were previously owned by Illinois utilities and that have been or will be converted into clean coal facilities (referred to as "retrofitted clean coal" sourcing agreements). The IPA says Section 1-75(a)(1) of the IPA Act further provides that the IPA's procurement plans "shall include electricity generated using clean coal."

The IPA states that FutureGen provides information that it will be positioned to deliver in excess of 140 MW of qualified clean coal electricity to the IPA portfolio by the end of 2017. FutureGen further asserts that a contract structure similar to the one employed by the Commission in Appendix K to the procurement plan approved in Docket No. 09-0373 for long-term renewable resources could be used for a clean coal procurement event.

The IPA agrees with FutureGen that, not only does the IPA Act require clean coal be included in the procurement plans, but also that a long-term contract structure will be required to ensure compliance with the provisions of the IPA Act. The IPA states that, as FutureGen notes, it will not be in a position to deliver qualified clean coal electricity until 2017, and there is no information in the record that there are other qualifying clean coal facilities currently operating in Illinois.

Therefore, the IPA requests that the Commission adopt the IPA's proposed alternative language set forth in its October 18, 2011 Response to Objections for Section 4.1 of the proposed Plan.

10. AER's Position

AER says that Section 1-75(d)(5) of the IPA Act provides that "[d]uring the 2009 procurement planning process and thereafter, the Agency and the Commission shall consider sourcing agreements covering electricity generated by power plants that were previously owned by Illinois utilities and that have been or will be converted into clean coal facilities, as defined by Section 1-10 of this Act."

AER believes the IPA has presented the Commission with a procurement plan that seeks proposals for such sourcing agreements under Section 1-75(d)(5) of the IPA Act. AER also believes the IPA Plan also provides a set of generalized specifications to guide parties desiring to propose such sourcing agreements. AER says the IPA Plan does not attempt to specify other parameters of the sourcing agreements (e.g., term, quantity, products, etc.) but rather leaves such terms open to parties developing such proposed sourcing agreements.

According to AER, the IPA Plan does not purport to pre-judge whether such proposed sourcing agreements will ultimately be accepted by the IPA and the Commission. AER states that nor does the IPA Plan purport to set forth the criteria which might be used by the Commission to evaluate such a Plan. AER says the IPA Plan envisions a review process where the proposed sourcing agreements will have to be "accepted and approved by the Commission." AER states that the IPA Plan also notes that any bid submissions arising from such sourcing agreements will be evaluated against benchmarks developed by the IPA and the Procurement Administrator. AER also claims the fact that no clean coal sourcing agreements have been considered in procurement plans to date as noted by at least one party is irrelevant to the question of whether the procurement plan under consideration in this proceeding should seek proposals for clean coal sourcing agreements with facilities other than the initial clean coal facility.

AER respectfully submits that in many respects, parties objecting to the IPA's clean coal proposal have prematurely raised objections and concerns that would be better addressed and resolved in the context of a separate Commission proceeding designed to review an actual proposed sourcing agreement. Rather than prematurely arriving at conclusions that could foreclose the possibility of ever reaching the state’s goal that by January 1, 2025, 25% of the electricity used in the state shall be generated by cost-effective clean coal facilities (Section 1-75(d) of the IPA Act), AER suggests the Commission should retain the IPA Plan's solicitation of such clean coal sourcing agreements, see what proposals result, and conduct a thorough review of such proposals at such time as they are submitted to the Commission.

11. Commission Conclusion

The IPA initially included in the filed Plan a proposal to solicit proposals for electricity from a clean coal facility. This proposal continues to be supported by FutureGen but, is opposed by most other parties. The IPA ultimately agreed that a clean coal proposal should not be included in the 2012 Plan.

The Commission concludes that a clean coal solicitation should not be included in the 2012 Plan. The Commission is convinced that including such a solicitation in the 2012 Plan would serve no practical purpose. The IPA, as well as other participants in the procurement process, has sufficient responsibilities and obligations without engaging in unnecessary activities. The Commission is open to considering solicitations in future procurement plans; however, as discussed herein, the Commission is not receptive to compelling the inefficient use of time and resources on unnecessary activities. In summary, the Commission finds that the IPA's alternative language set forth in its October 18, 2011 Response to Objections for Section 41 of the Plan is reasonable and is hereby adopted for inclusion in the Plan.

B. Purchase of Long-Term Renewables

1. ComEd's Position

ComEd indicates that it supports the proposal to procure RECs instead of a bundled energy and REC product; however, ComEd is concerned about procuring RECs on a long-term basis given the recent surge in retail customers, individually and through municipal aggregation, switching their supply service from ComEd to an ARES, and the extreme uncertainty about ComEd's future load. In addition, ComEd expresses concern that the dollars committed to long-term renewables pursuant to the 2010 Plan already account for over 45% of the current renewables budget. Furthermore, given the success of last year's short-term REC procurement, i.e., the IPA obtained RECs for under $1, ComEd sees no basis for the IPA's proposal to purchase additional, and much more expensive, long-term RECs for customers while displacing low cost short-term RECs.

ComEd argues that in load forecasting, 20 years is a very long time. Even over far shorter periods, ComEd claims total load in northern Illinois is driven by uncertain economic factors. In ComEd's view, one need look no further than the first year of Residual Volumes in Tables Q and R in the IPA Plan to see that that forecast uncertainty has already led to over-procurement of energy in some periods with a time horizon of only a few years. ComEd claims that significant competitive developments – including municipal aggregation – are making ComEd's share of total load increasingly uncertain. ComEd notes that the Plan acknowledges this load share risk, stating that "the IPA anticipates that the policy supporting competitive electricity markets will continue and strengthen, and that a portion of the eligible retail consumers currently served through the IPA portfolio will migrate towards ARES options." ComEd agrees that a dramatic acceleration in customer switching is currently underway, especially in the residential sector. ComEd believes the resulting uncertain but profound effect on load makes procurement of 20-year supply unwise.

ComEd states that as described in its forecast, in a period of three months the number of residential customers taking ARES service increased from essentially zero in March 2011 to over 70,000 in June 2011, and was projected to continue to grow at a pace of about 700 customers per day. Since ComEd submitted its forecast on July 15, 2011, it claims the pace of residential switching has increased. ComEd says that from June 1, 2011 to August 12, 2011, residential enrollment with ARES averaged 1,150 customers per day. If this trend were to continue, ComEd claims it could easily result that over a million residential customers switch to ARES service over the next two or three years. Given that approximately 80% of the usage for which energy will be procured in the June 2012 to May 2013 time period is residential usage – and residential switching is just in the formative stages – ComEd insists that it is wise to proceed with caution given the significant switching uncertainty facing the IPA. ComEd also agrees that over the long-term it is a possibility that the number of customers who take energy from ComEd that is procured pursuant to an IPA plan could fall to near zero.

In the forecast that it presented to the IPA, ComEd says it highlighted the municipal aggregation phenomenon and how ComEd expects it to grow over the next few years. In Table A in the Plan, the IPA presents the Current Status of Municipal Aggregation in Illinois. According to ComEd, Table A indicates that approximately 20 communities have taken steps just within the last year to aggregate the load of their citizens and switch that load to service from an ARES. ComEd is forecasting that an additional 60 communities will pass referendums approving municipal aggregation in the spring of 2012, and that the average size of these municipalities will be double the size of the 19 municipalities that have already passed referendums related to municipal aggregation. However, as ComEd pointed out in its forecast, it is very difficult at this point to project the future pace of residential switching. ComEd claims that even the low case in its forecast could be substantially underestimating the amount of switching that will actually occur. Moreover, ComEd notes this forecast only covers a five year period, not the more uncertain 20-year period for which the IPA proposes to procure RECs.

ComEd fully supports the IPA's conclusion that the RRB will change with ComEd's retained load, which is expected to decrease sharply over the next few years and may eventually fall to zero. Given that the RPS targets and annual RRB for each of the next 20 years are extremely uncertain, but clearly declining, ComEd insists additional long-term procurement poses serious risk, both to ComEd's bundled customers and also to winning suppliers that may have their contracted amounts cut as costs exceed caps in future years. ComEd says it cannot support the purchase of RECs on a long-term basis. ComEd claims this is especially true given that long-term procurement is not necessary. ComEd believes the availability and cost-effectiveness of short-term RECs that can meet the same renewable resource goals with far less risk is proven.

In its Order in Docket No. 09-0373, the Commission approved the procurement of 1,400,000 MWh of renewable energy for a term of 20 years. ComEd states that pursuant to that authorization, the IPA procured for ComEd 1,261,725 MWh of renewable energy, i.e., both energy and RECs, at an average bundled price of $55.18 per MWh. ComEd claims that using the REC budget as a guide, the REC component of those long-term bundled renewable energy contracts consume approximately 46% of the $49,419,560 renewable resource budget for this year ($22.868M ÷ $49.420M = 46.27%). ComEd says long-term renewables already account for a significant portion of the renewables budget. ComEd believes the IPA's proposal to procure significant additional amounts of long-term renewables would result in a very unbalanced portfolio and should not be pursued.

If the Commission decides to procure some additional long-term RECs, ComEd urges it to reduce the maximum contract term from 20 years to 10 years. ComEd claims this change will reduce the uncertainty surrounding the amount of "eligible load" over their term and reduce, but far from eliminate, the risks that the IPA will purchase more renewable energy resources than is needed or that there will be insufficient customers left to pay for those resources.

ComEd does not believe the Procurement Administrator can reasonably evaluate and compare all possible combinations of contract terms between 1 and 10 years as contemplated by the IPA Plan. ComEd asserts that as more bid terms are allowed, the expected liquidity of each term will tend to decline and the expected price will tend to rise. In ComEd's view, the IPA needs to provide greater clarity on how various contract terms can be fairly compared and cost-effectively procured before such a long-term procurement is allowed.

In its Response to Objections, ComEd notes that WoW postulates that the IPA's plan to use NPV comparisons to select winning bidders in the REC procurement event is biased towards short-term RECs. WoW provides an example that purports to show this. ComEd believes the example has a number of errors which makes it unusable in determining if the IPA's proposal to use NPV has merit.

ComEd claims that among those errors is WoW's unsupported assertion that $1-1 year RECs, $10-10 year RECs and $20-20 year RECs are all somehow equivalent. ComEd contends that WoW provides no evidence or rationale for this assumption upon which its entire example is based. ComEd believes it is unclear why anyone would agree to pay $20 a REC for 20 years when they can buy RECs annually for $1, or in what sense these values are equivalent. ComEd suggests that WoW means to imply that the costs of annual RECs will greatly increase over time and that, therefore, it makes sense to pay more now for longer-term RECs as a hedge against having to pay even higher prices in the future. According to ComEd, even if annual REC prices did greatly increase over time, and WoW simply assumes this, current 1 year REC prices would need to increase $2/year for the remaining 19 years in order for the total costs of the annual REC example to be equivalent to the total costs of the 20 year example, even without taking into account the time value of money. ComEd asserts that this results in a REC price in year 20 of $39. ComEd also contends that this result implies a wind price that is $39/MWh higher than the market price of energy, a result that is completely contrary to WoW's assumption that long-term renewables are cheaper than energy. Given the aforementioned flaws, ComEd believes it would be difficult to draw any meaningful conclusions from WoW's NPV example.

ComEd states that while WoW purports to object to the use of the NPVs, it seems comfortable in using that same approach to incorrectly conclude that ComEd's long-term bundled energy and REC contracts are providing economic benefit to customers presently. Aside from this inconsistency, ComEd asserts its analysis is fraught with error. ComEd states that in the last column of the NPV example, WoW mistakenly concludes that a $55/MWh PPA for energy and RECs saves customers money over the long term. ComEd says WoW makes this mistake by comparing a $55/MWh energy plus REC price to ComEd's $77.33/MWh Price to Compare. ComEd claims this Price to Compare includes energy, capacity, RECs, transmission, balancing and other costs. ComEd argues that from this erroneous example, WoW concludes that purchasing a bundled product of RECs plus energy saves money compared to purchasing only RECs. ComEd believes a better comparison would be the use of the latest prices obtained in the IPA procurements for energy (~ $34.77/MWh) and RECs ($1.05 for wind RECs), for a bundled price of just under $36/MWh. Based on these figures, ComEd says purchasing short-term RECs saved customers ~$19/MWh – or 35% over the bundled $55/MWh product.

According to ComEd, in Section B of this objection, WoW, in essence, argues that the future is uncertain and that power prices might go up for a variety of cited reasons. ComEd says WoW leaps from this observation to the conclusion that "In selecting those products the IPA should focus on long-term price stability for RECs to ensure price stability." ComEd agrees that the future is uncertain and that power prices may indeed rise over time in real terms. ComEd insists its future load also is uncertain and will likely decline over time. ComEd argues that this anticipated load loss makes signing long-term contracts more, not less, risky for ComEd customers, regardless of price uncertainty. ComEd also says that while WoW correctly notes the need to "consider" price stability for customers, it ignores the "lowest total cost over time" mandate in the same section of the PUA. While 20-year contracts for bundled REC plus energy might or might not contribute to price stability, depending upon whether the load they assumed was also stable, ComEd insists there is no evidence justifying the assumption that they are cheaper.

WoW recommends a mix of 75% long-term (i.e., 10-20 years) RECs and 25% 5-year RECs. ComEd states that no analysis or evidence is provided proving that this will achieve the "lowest total cost over time." ComEd maintains that short-term RECs obtained by the IPA recently are far less expensive than long-term RECs ($19 less as estimated above). ComEd also complains that WoW also fails to note that ComEd already has $23 million – or over 45% of its REC dollars – committed to pre-existing long-term contracts.

While ComEd would agree that the IPA should provide more details on how it intends to use NPV in its comparison of bids before the Commission approves its use, WoW's conclusions that such a method is biased towards short-term RECs or that purchasing a bundled product of long-term energy plus RECs saves customers money are in error and should be rejected.

2. AIC's Position

The IPA proposes an annual RRB for multiple compliance years. AIC states that in the executive summary, the IPA proposes an RRB for 12 years; however, in Section 3.3, the IPA proposes to create an RRB for 20 compliance years. AIC says this difference is not explained and requires clarification or correction. After the creation of the RRB, the IPA proposes to develop a confidential forward price curve which will be used to back out existing long-term renewable contracts to yield a NRRB. The IPA then factors the NRRB by 50% to create a hard budget limit. The IPA would then solicit REC bids for multiple compliance years and once received, such bids would be sorted according to price and source (solar, wind, etc.). Bids are then selected in a manner that yields at least the minimum carve out requirements after existing long-term renewable contracts are added to the new REC volumes. AIC says the IPA has outlined a proposal to calculate a NRRB over multiple compliance years based on an extrapolation of the low forecast scenario provided by AIC.

In AIC's view, this proposal for RECs is inconsistent with the hedging strategy associated with energy and capacity and no explanation or analysis is provided regarding this inconsistency. The IPA has recommended hedging energy and capacity based on a three-year laddered approach, which results in the prompt year being hedged at 100% of forecast, year two at 70%, and year three at 35%. AIC indicates that it estimates that existing long-term PPAs account for approximately 53% of the renewable target in the prompt year, 51% in year two, 46% in year three, 42% in year four and 37% in year five. Beyond the fifth year, AIC says the quantity of existing hedges is unknown because a forecast beyond year five does not exist.

AIC states that using the IPA criteria for hedging energy and capacity as a guide, the IPA should hedge the remaining target for the prompt year (~47%) so as to reach 100% of target. AIC suggests it may also be appropriate to hedge a portion of year two (~19%) so as to reach 70% of target, although uncertainty in load due to an increase in residential switching may suggest a more cautious approach is prudent. For years three and beyond, AIC says no additional purchases would be pursued because the existing hedge is already in excess of 35% of target.

AIC also asserts that since it submitted its forecast to the IPA on July 15, residential switching to ARES has increased from a negligible quantity to approximately 17,000 customers. AIC says the number of residential customers switching to ARES appears to be accelerating, but given the lack of experience associated with residential switching, it will be difficult to accurately forecast the amount of fixed price load until such time as trends in the residential market become more apparent. AIC believes adding additional long-term purchases at this time creates unnecessary risk to customers, and suggests caution is the appropriate near term course of action.

AIC also notes that a forecast beyond five years has not been included in the Plan, whereas in all previous Plans approved by the Commission, the Plan contained a forecast and specific quantities for solicitation. AIC says that while the IPA intends a methodology for creating a long-term forecast, the proposal ultimately contains no long-term forecast, nor details regarding the terms and quantities of RECs to be solicited. AIC believes it is noteworthy that Section 16-111.5(b)(3)(iv) of the PUA requires the proposed term structure and mix of products to be provided in the Plan. AIC maintains that in past Plans, the IPA was very specific in the quantities and associated terms of RECs (as well as energy and capacity). AIC is concerned that this is not the case with this proposal.

AIC recommends the IPA solicit RECs only for the prompt year and at the target quantities and budget cap provided in the Plan. AIC suggests the IPA could solicit

RECs for year two, but such quantities should only be to a level consistent with the hedging strategy associated with energy and capacity unless the IPA brings forth an analysis which shows a different hedging plan is appropriate. AIC insists that any solicitation greater than year two may subject customers to unnecessary price risk due to recent customer migration developments having a direct impact on the load projections.

If the Commission disagrees and determines that the IPA proposal for long-term RECs should be pursued, AIC requests the Commission require the Plan include a long term forecast and clarify whether this should be for 12 or 20 years. AIC believes this forecast should include yearly targets and budgets. AIC says such a forecast could be created by IPA or the IPA could request AIC to create such a forecast, and the IPA can then review and affirm such forecast.

In its Reply to Responses, AIC states that if the IPA desires to propose long-term RECs in future Plan years, it is encouraged that the IPA states it will provide a specific proposal. AIC suggests including the proposed mix of quantities and terms in any future Plan that contemplates long-term RECs would be consistent with Section 16-111.5(b) of the PUA where it states that “the Plan shall specifically identify the wholesale products to be procured following plan approval." AIC notes that Section 16-111.5(b)(3)(iv) of the PUA continues by stating the Plan should include “the proposed mix and selection of standard wholesale products . . .” and further defines standard wholesale products as “including but not limited to . . .” energy and capacity. AIC believes these elements as prescribed by statute should be included in any proposal that contemplates long-term REC procurements.

AIC states that the proposed mix of quantities and terms in the Plan should be based on a forecast which is also included in the Plan. AIC believes including a forecast is not only consistent with the requirement of the statute, but it is also consistent with prudent planning and hedging practices since forecast data is needed to properly determine the proposed quantity and term of RECs to be solicited. AIC reiterates that it is willing to work with the IPA to create a long-term forecast in future planning years.

In its Reply tor Responses, AIC says WoW has taken its recommendation out of context. AIC says it recommended the IPA solicit RECs for the prompt year only. AIC continues by stating if the Commission disagrees and determines that if the original IPA proposal for long-term RECs should be pursued, the Plan should first clarify whether the maximum term desired is 12 or 20 years (because the original IPA proposal listed both terms, thus creating confusion) and second should include a forecast along with a specific mix of quantities and terms to be solicited.

AIC notes that the revised IPA proposal desires to pursue one year RECs only. AIC is in agreement with this proposal. Assuming the Commission agrees with the revised IPA proposal, AIC says it would render moot the issue of whether to include a long-term forecast pertaining to this Plan. AIC claims the point remains for any future

Plan that ponders long-term RECs should include a forecast and identify a specific mix of quantities and terms to be solicited. AIC says this will ensure the Plan is consistent with the requirements of the statute and prudent hedging and planning practices.

AIC sees no need to include a long-term forecast in the Plan given a scenario where the Commission agrees with the revised IPA proposal of procuring one year RECs only. However, AIC believes any future Plan that contemplates long-term purchases should include a forecast so as to be consistent with the statutory requirement and prudent hedging and planning practices. AIC argues that if such a forecast is deemed inaccurate, it illuminates the risks associated with long-term purchases and may suggest a more cautious approach. In addition, AIC believes that any proposal for long-term purchases should include the mix and quantities of terms to be solicited along with supporting analysis.

AIC also indicates it has several concerns with the AG's suggestion that the Procurement Administrator accept bids of varying terms and evaluate bids with price as the guiding principle. AIC expresses concern that the Plan contains a forecast and budget for renewable resources for the prompt year only. AIC maintains that the statute requires that any proposed hedging strategy be prepared after consideration of a forecast. AIC also says that other than the prompt year, the Plan contains no proposal regarding a mix of quantities and associated terms. AIC believes such details are also required pursuant to the statute. AIC also states that the proposal has not described a methodology as to how bids and quantities of varying terms would be evaluated. AIC says presumably this could be done by the IPA and the Procurement Administrator during the implementation phase. Without an upfront understanding of the methodology associated with such evaluation, AIC suggests it would be a leap of faith for the Commission to assume the resulting outcome would balance the desire to achieve low cost and price stability.

For future Plan years where longer term RECs are proposed, AIC believes that the uncertainty surrounding the evaluation methodology could be removed if a specific mix of quantities and terms were provided within the Plan. In such a case, AIC says the evaluation methodology would be known in advance and would simply become the lowest price bids associated with each desired term and with quantities up to those specified in the Plan and subject to the benchmarks developed in the implementation phase. AIC recommends the AG's proposal be rejected by the Commission and the revised IPA proposal to procure only one year RECs be accepted.

3. Exelon's Position

Exelon argues that given the complications with accurately predicting the volume requirements and creating the required benchmarks for long-term RECs, it is unclear why the IPA has proposed solicitations for RECs with terms as long as 20 years. Exelon says the Plan offers no explanation for this deviation from past REC procurement practices. Exelon finds this deviation particularly puzzling because the IPA has acknowledged that the RPS obligation was successfully met in past years through solicitations of annual RECs only. Exelon says the procurement of annual RECs by the IPA has worked to ensure lowest-cost compliance with the Illinois RPS, and it is unclear why the IPA proposes to change its approach and embrace an option – long-term REC procurement – with no track record and uncertain costs to consumers.

Exelon contends that REC procurements beyond one compliance year are inherently risky because predicting the volume requirements is complicated by retail choice, and the budget is variable largely due to the long-term bundled contract obligations. Exelon says the IPA acknowledges that as retail competition develops in Illinois, the RPS volume goals – and the available budget – will diminish over time. Additionally, Exelon claims prices for RECs have been volatile over the past few years, and there is no visible market for RECs beyond one year.

Exelon calls the proposal for long-term RECs arbitrary and claims it introduces significant complications by requiring projections over decades that dramatically increase the risk of locking in fixed-price contracts now that will be in excess of available budget dollars in future years. To seek bids for long-term RECs, the IPA proposes to create a NRRB, which first requires estimating the annual portfolio requirements for the next 20 years. Exelon says the IPA then applies the rate cap to establish the RRB, which then backs out the confidential "implied" REC prices from the long-term contracts. Exelon says those implied REC prices are based off a confidential 20-year future price curve that was generated by the IPA when those contracts were first entered into. Lastly, the IPA proposes to factor the NRBB by 50%, which Exelon says is neither intuitive nor explained, and then solicit REC bids for up to the 20-year horizon.

In Exelon's view, predicting the annual portfolio requirements is difficult under normal circumstances. Exelon believes, however, that retail choice has made the requirements even more uncertain and highly variable, particularly with the advent of municipal aggregation and recent positive developments in retail choice for residential customers. Exelon says the rate at which customers are going to switch over the next year is difficult to predict, and the quality of the forecast degrades rapidly over 20 years.

Exelon says the required price benchmark, against which the IPA proposes to compare the bids, must consider the relevant market price for a 20-year REC contract. Exelon contends no such market price exists and the visibility for REC prices in the competitive market is about one year. In Exelon's view, there is no adequate way for the IPA to establish a proper price benchmark for long-term RECs and satisfy its requirement to purchase "cost-effective" renewable resources.

Exelon insists the Plan offers no justification, let alone purported benefits, as to why it includes a substantially more complicated and risky renewable resources procurement proposal. Exelon claims the Plan also fails to explain how the 20-year fixed-price REC contracts will be paid if the budget is exhausted due to the statutory rate caps, despite acknowledging that the RRB will diminish over the coming years.

While the reason behind the long-term REC proposal is not identified in the Plan, Exelon claims renewable energy developers have traditionally intervened in the procurement dockets requesting longer term REC procurements as a means to help secure financing. Exelon claims the IPA already has a mechanism in place to address these concerns without subjecting Illinois consumers to greater risk. Exelon says the General Assembly established the Renewable Energy Resources Fund ("RERF") as a means to support renewable energy generation development without further increasing the costs and price risks to customers. In light of this existing mechanism designed to address these concerns, Exelon believes the IPA should not enter into long-term contracts that by its own admission are risky and more costly.

In 2009, the Commission approved the procurement of certain amounts of bundled energy and RECs subject to 20-year agreements. Exelon says that as a result of that proceeding, the IPA procured 1,400,000 MWh of renewable energy under long-term agreements. Exelon suggests these contracts already form a significant percentage of the total available budget. Exelon believes that proposing to procure more long-term RECs would possibly be understandable if the IPA were struggling to procure the necessary RECs through its annual procurements. Exelon argues that this is not the case and that the annual procurements have resulted in the acquisition of lowest-cost RECs to satisfy the RPS requirements.

In its Response to Objections, Exelon maintains that the Commission should require the IPA to modify the Plan to eliminate the proposal to procure long-term RECs. Exelon also notes that WoW argues that the IPA's usage of NPV is biased toward the procurement of short-term RECs. Exelon argues that because WoW uses flawed and unjustified assumptions, Exelon cannot agree with the conclusions WoW reaches. Exelon states that in WoW's NPV tables, WoW assumes that $1 1-year RECs, $10 10-year RECs, and $20 20-year RECs "are basically equivalent products in 2012 dollars,"9 and then constructs its NPV calculation based on this assumption. Exelon complains that WoW does not support or explain its assumption, and Exelon claims this flawed assumption renders its model unsuitable and its conclusions unreliable.

Exelon says WoW additionally argues that multi-year RECs should be procured within the "hard budget limit," while one-year RECs should be procured outside the hard budget limit. Exelon claims WoW does not clarify its methodology for reaching this conclusion, nor does it provide any support for why one-year RECs should be procured outside the "hard budget limit." Exelon asserts that rather than further complicating the REC procurement process with WoW's proposal of divvying up procurement among "hard" and "soft" budgets, Exelon agrees with Staff that the IPA should simplify and clarify its NPV calculations and provide the bases for its assumptions. Exelon reiterates that the procurement of long-term RECs does not provide benefits to consumers but rather increases risk to consumers and suppliers

4. ICEA's Position

In the Plan, the IPA proposes to solicit bids for RECs for periods up to 20 years. ICEA opposes this proposal because it provides no benefits to consumers but will assuredly increase prices for ARES' customers. ICEA states that by law, at least 50% of ARES' RPS compliance obligation must be satisfied via payment of ACPs. ICEA says the ACP rate is directly derived from the amount eligible customers pay for renewable resources procured by the IPA. ICEA asserts that longer-term REC contracts are inherently more expensive, and projecting both the volume requirements and REC market prices for anything longer than a year is fundamentally risky.

ICEA states that pursuant to the Commission's Order in Docket No. 09-0373, the IPA has already procured almost half of the 2012-2103 renewable resources requirement through 20-year contracts at an average bundled price of $55.18 per MWh. ICEA says although the portion of the bundled price that is attributable to the REC budget is unknown because it is calculated based on a confidential market forecast, when based on publicly available information, an estimated REC price of $15 is likely close to the actual implied cost. At an estimated $15, ICEA says the long-term contract will account for over 40% of next year's total REC budget, and significantly increase the ACP. Compare that to the less than $1 paid on average for 1-year RECs procured by the IPA last year and ICEA claims it is clear that longer-term RECs are exorbitantly more expensive. In ICEA's view, since long-term renewables already account for a significant portion of the renewable budget, the proposal to procure additional amounts of long-term renewables would result in a very unbalanced portfolio and an unjustified increase to the ACP and, thus, should not be permitted. Given that the utilities are forecasting the range of residential customer switching in 2013 to be as high as 53%, ICEA believes further additional long-term contracting puts unnecessary risk on Illinois customers whether served by the utilities or ARES.

ICEA says in addition to acknowledging the complications and risks associated with the renewable resources procurement, the IPA recognizes that in prior years, the RPS obligation was successfully met through solicitations of annual RECs only. ICEA maintains that recent short-term wind RECs have been procured for under $1/REC. While solar RECs are less plentiful, and thus more expensive, ICEA claims the short-term market prices for solar RECs have been declining steadily in other states.

According to ICEA, the IPA inexplicably proposes to complicate the REC procurement process and drastically increase costs by proposing terms as long as 20 years. ICEA says the IPA has provided no explanation as to why it seeks to increase the REC contract terms, let alone shown that it meets the requirement to procure "cost-effective" renewable energy resources. Because the REC market is not visible beyond a few years, ICEA contends there is no way for the IPA to create a reliable benchmark for long-term RECs. ICEA believes this lack of long-term reliable price benchmarking in turn makes it impossible for the IPA to demonstrate that its Plan meets the "cost-effective" test.

ICEA argues that the IPA already has a mechanism to procure long-term REC contracts that places no additional risk on Illinois consumers. ICEA says the RERF was established by the General Assembly for the IPA to procure long-term renewable energy resources contracts without further increasing the costs and price risks to customers. Given this statutory obligation, ICEA believes it is not justifiable to allow the IPA to use this process to enter into long-term contracts that by its own admission are risky and more costly.

In its Response to Objections, ICEA says the only party in favor of 20-year RECs was WoW. In its Objections, WoW argues that the IPA's usage of NPV is biased toward the procurement of short-term RECs. While ICEA agrees with Staff that the IPA's proposal to use NPV should be clarified, ICEA disagrees with WoW's calculations. ICEA believes it is unclear from WoW's NPV table how it actually reached its conclusions. As ICEA understands it, WoW concluded that $1 1-year RECs, $10 10-year RECs, and $20 20-year RECs are in some way equivalent, and then constructed its NPV calculation based on that assumption. ICEA complains that WoW does not explain how it developed its assumptions or why it chose the values that it did. According to ICEA, any NPV model is only as good as the assumed values: the use of unjustified and unexplained inputs limits the significance of WoW's conclusions.

Regardless, ICEA says the underlying theme of WoW's Objection seems to be that the market risk of REC prices increases over time, and therefore, locking in longer-term contracts would provide price stability for consumers. ICEA claims that WoW ignores the risk of coupling long-term REC procurement with uncertain load forecasts. ICEA says the IPA itself has recognized the significant risk posed by load migration and the imprudence of entering into long-term contracts based on current assumptions. According to ICEA, even if WoW's proposal would result in stable prices, because the amount of load over which those prices are spread is uncertain, long-term REC procurement would actually increase risk to consumers. ICEA says WoW's proposal to lock-in REC prices, without correspondingly locking in the amount of load over which those prices are paid, does not reduce volatility but instead magnifies risks to consumers and suppliers. ICEA believes this proposal does not meet the PUA's "lowest total cost over time" standard and should be rejected.

5. Constellation's Position

In Constellation's view, the Plan does not contain sufficient justification for procuring long-term renewable contracts for a second year in a row – from a legal perspective, from a cost perspective, or from a policy perspective. Constellation says long-term procurements are not required under the PUA as part of the procurement. Constellation says the only vehicle for entering into long-term contracts for renewable resources is through the RRB(to which utilities and ARES both pay). Constellation says the PUA requires that a five-year time horizon be considered when formulating a Plan. To the extent that the Plan seeks to procure products that fall outside of that window, Constellation asserts the IPA does not possess such authority.

Constellation argues that the Plan fails to satisfy the requirement that it “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.” Constellation claims it contains no analysis or objective view of the market showing that these long-term contracts are in the best interests of consumers. Constellation says for example, it contains no data or analysis of the long-term renewable contracts awarded under last year's Plan, and their costs to consumers or other effects on the market.

Constellation asserts that the provisions of the Plan, particularly those done under the auspices of the RPS, have a direct impact on competitive wholesale and retail markets and, ultimately, on consumers' interests. While the electric utilities entering into long-term contracts have full cost pass-through protection, Constellation says customers ultimately will pay. According to Constellation, such procurements are based on a “forecast” where no competitive market actually exists. Constellation also claims they have little or nothing to do with promoting competition, given that the developers have no exposure to competitive market outcomes. Constellation contends that long-term contracts prevent customers from realizing the benefits of the substantial price reductions that renewable technologies have seen.

Although ARES are not themselves parties to the long-term contracts, Constellation asserts that ARES are nevertheless directly affected by their use. Constellation claims the premiums for renewable energy implicit in the 20-year, long-term contracts will be included in the annual calculation of the RPS bill-impact cap. Constellation believes that by definition, this also means that the premiums implicit in the 20-year, long-term contracts will also be included in the Retail Electric Suppliers ("RES") funded ACP since the ACP rate is a direct derivation of the IPA's RPS procurement price. Since by law at least 50% of RES RPS compliance is via payment of ACPs, Constellation says the premiums created by these contracts will potentially increase prices for all Illinois customers, not just eligible retail customers served by the IPA.

According to Constellation, the stated goals of minimizing customer bill impacts and providing a funding source for long-term renewable energy contract premiums via the IPA RERF is a preferable and statutorily correct approach to hedge any asserted impact of carbon controls on the state and to support the development of incremental renewable resources in the state. Constellation also asserts that since the payments that have been received and are anticipated can be reasonably projected, there is no reason that the IPA cannot utilize those funds in a procurement for long-term renewable resources delivery and therefore capture any purported benefits of current federal renewable energy incentives and hedging of the impact of potential federal carbon controls.

Constellation also asserts that inclusion of long-term contracts needlessly complicates the IPA's procurement activities going forward. The IPA RERF procurement “shall not exceed the winning bid prices paid for like resources procured for electric utilities required to comply with 1-75 of this [IPA] Act.” In Constellation's view, this statutory provision is another reminder of the intent of the Illinois General Assembly as it relates to long-term contracting. There are greater complexities of using long-term contracts than shorter-term energy or energy plus RECs, when the true costs are not known and are subject to change over time. As the Plan notes, “[m]eeting the RPS obligation is growing more complicated over time with volume requirements, budgets, and the costs of pre-existing contract obligations all operating in a variable manner. Additionally, because the forward cost curve governing the applied costs for RECs delivered under the LTPPAs is confidential, a final RRB for each utility cannot be presented in this Plan.” Constellation believes such complexities will only increase this year and in future years. According to Constellation, this hinders the ability of the IPA to actually meet the RPS standard. Constellation contends that anything that can be done to streamline the RPS process, to provide greater transparency, and to ensure that the RPS standard is able to be met, while not adversely affecting customers, should be given great weight; long-term contracts run counter to that fundamental premise.

6. RESA's Position

RESA believes that the IPA should continue the approach it took in the 2011 Procurement Plan, approved in Docket No. 10-0563, with respect to the procurement of one-year RECs. RESA says the Commission’s order approved the IPA’s proposal to include in the 2011 Plan the acquisition of only unbundled one-year RECs with no long-term renewable energy contracts and specifically found that the IPA’s proposal met the requirement of Section 1-75 (c)(1) of the IPA Act of including cost-effective renewable energy resources.

According to RESA, average prices for REC’s have dropped from $30, to $20, to $4.50 to approximately $1.00 in four years. In RESA's view, there appears to be a significant oversupply in the renewables market in Illinois. RESA also suggests that with the Illinois preference dissolving, the over-saturated REC market should allow low compliance costs for the RPS throughout the medium-term. RESA claims this position is confirmed by the recent report submitted, pursuant to the requirements of Subsection 1-75(c) of the IPA Act, by the Commission to the Illinois General Assembly. RESA says the June 2012 Report to the Illinois General Assembly Concerning Spending Limits on Renewable Energy Resource Procurement concluded that renewable energy resource generating capacity has been on the rise (and renewable energy prices have been on the decline) and that the Commission found that there are factors favoring the continued development of renewable energy resource generating capacity.

RESA believes that now is not the time to be making any long, or even medium, term procurement of renewable energy resources. In addition to the fact that one-year RECs are plentiful and inexpensive, RESA claims there is great uncertainty about the amount of load migration that will be taking place in the coming years. RESA says there has been a great deal of migration of residential customers in the ComEd service territory. RESA notes there are currently 21 ARES in ComEd’s service territory certified to serve residential customers. RESA also indicates that the latest migration statistics show that, as of July 31, 2011, approximately 92,000 residential customers of AIC and

ComEd are being served by RES. RESA believes this number is particularly significant in that there were virtually no residential customers being served by RES as of the end of calendar 2010.

RESA also asserts that municipal aggregation is on the rise in Illinois. RESA states that currently, there are 20 municipalities which adopted opt-out municipal aggregation in referenda. RESA says this number is expected to increase dramatically in the April 2012 elections. RESA contends that the utilization of one-year RECS for the 2012 Plan will result in a low-cost supply of renewable energy resources and will allow time to assess the impact of municipal aggregation and increased competition for residential customers on the level of migration from the Illinois electric utilities. RESA suggests the issue of medium and long-term procurement of renewable energy resources can be better addressed in the 2013 power procurement Plan after another year of experience.

In its Reply to Responses, RESA applauds the IPA's decision. RESA says the Objections of electric utilities, RESs, electric generation companies, and Staff overwhelming demonstrated that use of one-year RECs continues to be the best way of meeting the requirements of the IPA Act. RESA believes the issue of medium and long-term procurement of renewable energy resources can be better addressed in the 2013 power procurement plan after another year of experience.

According to RESA, WoW claims that the uncertainty of future electric utility load does not warrant the procurement of one-year RECs. WoW asserts that the IPA should still procure multi-year RECS because some of those multi-year REC contracts can also be cancelled depending upon the amount of load migration. RESA believes the IPA's approach of procuring one-year RECs, which are plentiful and inexpensive, for the 2012 Plan and deferring the issue of multi-year RECs until future plans when there has been more experience with load migration makes much more sense than entering into long-term REC contracts only to cancel them later.

7. Staff's Position

Staff believes it is unnecessary to specify a conservative budget (subject to change in the future) for the proximate plan year (in this case 2012-2013). Rather, Staff recommends continuing the established practice of computing a definitive budget for the proximate plan year. Staff notes that the Plan includes just such a definitive budget in Tables AA and BB and DD and EE for AIC and ComEd, respectively. As such, Staff concludes that the IPA intends for its proposal to apply to the 19 plan years following the proximate plan year. Also, the IPA proposes to "[a]pply the confidential future price curve generated by the IPA and submitted to the ICC to back out Long Term Power Purchase Agreements (LTPPA) cost obligations from the RRB to yield a Net Renewable Resources Budget (NRRB) for each of the future years." Staff concurs in the use of that future price curve (developed in 2010), but, Staff believes that price curve should be made public rather than kept confidential. Furthermore, Staff believes the Plan should be made clear that similar procedures will be utilized in the future, as necessary, to back out other multi-year renewable contracts that may be executed, rather than continuing to back out only the December 2010 contracts.

Staff believes the IPA proposal to invite renewable resource bids for periods between 1 and 20 years is too vague and open-ended, and thus should be rejected in favor of 1 year contracts for the proximate planning period. Additionally, Staff complains that the IPA proposal fails to explain how it would choose between bids of differing lengths. In its objections, Staff provides several examples intended to demonstrate the difficulty inherent in comparing bids of differing lengths.

Staff suggests that since the IPA Plan fails to clarify how winners would be selected among a pool of renewable energy products with varying durations, presumably that would be an element of the IPA's proposal left entirely to the implementation phase of the plan, which is largely under the control of the IPA and its procurement administrators. In Staff's view, that would grant an unacceptable level of autonomy to the IPA and its procurement administrators.

In Staff's view, the IPA's plan to rank bids according to NPV does not resolve the issue of choosing between bids of differing lengths. Staff acknowledges that, for ease of exposition, Staff's description of the issue did not delve into the issue of discounting future cash flows, which is the basic idea behind NPV calculations. Staff insists that merely reducing bids for multiple and varying time periods to a common and single time period through NPV computations does not, in any way, address the underlying requirements for the bid evaluator to develop expectations for future renewable price offers and to establish a way of translating policy-makers' preferences between minimizing expected cost and minimizing risk into an appropriate discount rate.

Staff recommends that the Commission reject, without prejudice, the IPA's proposal to invite bids for greater than one year during the 2012 procurement season, leaving the resolution of longer-term contract acquisition to future plans.

In its Response to Objections, Staff indicates that it disagrees with WoW's claim that the IPA's proposed 50% adjustment to the budget available for long-term renewable purchases is "unduly constraining." As Staff understands the IPA's proposal, the 50% adjustment would apply to spending on contracts entered into during each procurement event, rather than the cumulative amount spent. Staff believes it is feasible to spend more than 50% of each year's budget on one-year contracts and the remaining portion on a mix of 20-year, 10-year, and 5-year contracts, and still end-up over the long run with a portfolio consisting of, for example, 50% 20-year contracts, 25% 10-year contracts, 15% 5-year contracts, and as little as 10% one-year contracts (by dollars spent and, if there are no long-run pricing biases, by number of RECs, as well). Staff says the IPA's proposed 50% adjustment to the budget available for long-term renewable purchases is not "unduly constraining." Staff also says if the Commission decides to approve more RFPs for long-term renewable contracts, the IPA's 50% proposal, or something like it, should be employed as part of a strategy for dealing with potential load migration and other contingencies that may reduce the spending limit imposed by statute.

In its Reply to Responses, Staff indicates that it disagrees with the AG's proposal to grant the IPA procurement administrator flexibility to assess whether the renewable resources market contains sufficient resources, in the form of short-term RECs, bundled RECs and electricity, or long-term contracts, to support Illinois's renewable resources portfolio requirements over the coming years.

Staff believes that for such a proposal to make any sense, the procurement administrator would have to form expectations of future REC prices. For example, questions what is better, a contract for delivery of RECs in Plan Year 2012 for $150 per REC or a contract for delivery of RECs in Plan Years 2012 through 2016 for $100 per REC. Staff suggests that since $100 is less than $150, it seems like the logical choice is the three-year deal, except if you believe the price of one-year RECs will fall by somewhat more than $25 per year over the next four years. Staff says the PUA defines the role for the procurement administrator. In that role, Staff claims the procurement administrator selects winning and losing bids, based solely on comparing bid prices. Staff believes it is a considerable stretch of statutory interpretation to assume that the procurement administrator is permitted to deviate from such a straightforward comparison of known prices, and to make selections based on its own mere expectations of prices. Even if the law permits the IPA's consultants to assume such a role, Staff asserts that it would be preferable for procurement plans to include separate target quantities for one to three specific time periods, not necessarily the same time periods or the same number of time periods each plan. Staff says bidders would compete within each time period, not across time periods. Staff suggests that in this way, competition among market participants, rather than speculation by the procurement administrator, would ultimately decide winners and losers.

8. WoW's Position

WoW states that the 2012 Plan simply states that bids would be evaluated and ranked using a NPV, without more detail. WoW believes a NPV methodology is biased in favor of RECs with shorter durations. According to WoW, this methodology fails to manage the procurement of RECs in a manner that will ensure an environmentally sustainable electric service and provide price stability for ratepayers. WoW asserts that shorter-term RECs, while low cost now, do not ensure that renewable energy resources will be built in sufficient quantity so as to meet growing RPS needs in the MISO and PJM transmission networks. WoW claims that RPS requirements in PJM and MISO states will increase over the next 15 to 20 years. As the requirements increase, WoW says the existing merchant wind farms will enter into PPAs and be unavailable to provide REC-only products. Unless steps are taken to foster some development of renewable resources, WoW is concerned that the supply of available renewable energy resources will diminish and the price of RECs and renewable energy will increase to match market prices needed to build new resources.

WoW claims the use of the NPV methodology will cause the IPA to award contracts to short duration RECs which do not foster construction of new renewable energy resources. In effect, WoW believes the NPV methodology exposes ratepayers to possible price spikes in renewable energy products. WoW suggests the IPA can prevent this by establishing a portfolio of products of varying duration that gives long-term price stability from renewable energy resources.

WoW notes that the 2012 Plan does not provide a lot of detail around the NPV methodology being proposed, so the IPA either needs to clarify this methodology and show that it is a just and reasonable method, otherwise WoW recommends the overall REC process be changed.

WoW provides calculations in its objections intended to show the bias of the NPV method toward short duration RECs. According to WoW, the IPA should procure a portfolio of products, and not be biased toward one-year or short-term RECs. WoW believes a portfolio of renewable products will ensure long-term stability of REC prices in Illinois, will hedge against energy price volatility and will replace the thousands of megawatts of generation that are expected to retire or go into mothball status within the next two to five years due to U.S. Environmental Protection Agency regulations.

WoW claims the purpose of the RPS is to change the utilities' energy portfolio so it reflects 25% of renewable energy resources. WoW says in managing the procurement of the renewable resources the IPA is to develop a portfolio "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." WoW says the statute gives the IPA discretion to procure either unbundled RECs or bundled REC products to meet that requirement. WoW argues that in selecting those products the IPA should focus on long-term price stability for RECs.

WoW states that within PJM and MISO there are eighteen states and the District of Columbia that have energy portfolio standards or goals. WoW says each requires an incrementally increasing amount of energy from renewable resources, with some standards active beyond 2026. PJM and MISO will need to have enough renewable resources within their footprints for states to meet the requirements of their RPS energy portfolio standards and goals. WoW claims a shortage will result in REC price volatility. To avoid the price spikes, WoW suggests longer-term renewable products need to be procured. WoW says that short-term REC products, while cost-effective in the short run, will not build new renewable resources. WoW contends that short-term, unbundled RECs yield a fraction of the revenue needed to build new generation. WoW asserts that without new renewable resources the demand will cause a shortage in renewable resources resulting in a potential spike in REC prices. WoW believes there is value in taking steps to avoid this price volatility. WoW says a plan that encompasses short-term and long-term products, procuring unbundled RECs and bundled renewable energy will provide a stream of development that will temper REC prices over the long term.

WoW suggests another motivating factor for procuring a portfolio of renewable products is the potential reduction of generation capacity in PJM and MISO within the mid-term. WoW says the U.S. Environmental Protection Agency is finalizing four proposed regulations that will result in retirements or reduced usage of coal plants in MISO and PJM. WoW claims these regulations are being developed now and compliance starts sometime between 2012 and 2016, depending on the regulation.

WoW also suggests that given that the General Assembly set a renewable energy resource goal of 25% by 2025 it must have envisioned that the RPS would foster development of renewable generation that could offset the 40+ year old coal plants in the Midwest that would be retiring over the eighteen year period of the RPS. To foster development of such renewable resources, WoW believes the IPA needs to use longer term renewable products that require energy delivery. WoW maintains that a portfolio of short, mid and long-term renewable energy products should not only be used to develop replacement renewable generation but also provide REC price stability and provide a hedge against long-term price volatility, like the IPA does in its standard energy procurement.

WoW recommends the IPA offer a stated portfolio of products ranging from 1 year to 20 years. WoW suggests each product type and duration should have its own benchmark. WoW says the volume of multi-year products should be based on the expected load scenarios provided by the utilities. WoW also says the multi-year products should be procured within the hard budget limit and one-year RECs outside of the hard budget limit. If the cost obligations of the multi-year bids that are awarded contracts exceed the hard budget limit in 2012, then WoW suggests the IPA is to select the method of rejecting bids.

To allow for the easiest and most effective selection of bids, WoW proposes that the IPA procure a portfolio of REC products with standardized terms of 1, 5, 10 and 20 years. WoW believes that standardizing contract term lengths in this way allows for the easiest comparison of bids of a similar duration and makes the bid-selection process more efficient. Without standardized durations, WoW says the IPA and procurement monitor will be forced to compare pricing of a one-year REC with that of a 20-year REC, which is not an “apples-to-apples” comparison. WoW also suggests it makes the assessment of the statutorily-required preference for “benefits of price stability” that much harder to assess.

WoW recommends the renewable energy portfolio for 2012 be comprised of 5/10/20 year REC products with a majority being longer term products; reflecting a portfolio split of approximately 25%/50%/25%. WoW suggests this would take advantage of the favorable market conditions for long-term products. WoW provides tables with volume estimates of renewable energy that would be procured for ComEd and AIC using the expected load scenarios and the low load scenarios.

WoW claims several factors impact REC pricing in today’s markets, including, but not limited to resource type, location, and duration. Because the IPA is proposing to secure RECs from multiple resource types and for multiple durations, WoW believes the IPA should apply confidential benchmarks for each length and resource type (i.e., one-year solar, one-year wind, five-year solar, five-year wind, etc). WoW claims using multiple benchmarks in this way will allow the IPA to assess bids' on their overall merits of both price and their benefits of price stability, as required by statute. In the event that two bids for a product have an identical price, WoW suggests the selection of the in-state resource would acknowledge the economic benefit that project would provide Illinois above an out of state project, given all factors being equal -- including price.

According to WoW, the expected load scenario in conjunction with the net RRB proposal (also referred to as the hard budget limit in the 2012 Plan) would suffice. WoW says the hard budget limit will act as a cap on the number of multi-year RECs that may be procured. If the cost obligation of all of the multi-year REC bids that would be used to meet the RFP quantity exceeds the hard budget limit, WoW suggests the IPA would select the bids that would be rejected so as to reduce the cost obligation of multi-year RECs to below the hard budget limit. WoW says the multi-year REC bids that were rejected would become one year RECs.

In its Response to Objections, WoW notes that some parties highlight the fact that the load forecasts are only for five years and that the utilities' load may change in the years beyond the forecast due to migration or switching among the utilities and the ARES. WoW asserts that in those years, the real risk of load migration rests with the supplier, not the utility. WoW claims that if a procurement results in the RRB being exceeded, then some multi-year REC contracts could be cancelled. WoW contends that the supplier is the party that assumes the risk of the loss of those contracts and the need to find a new buyer for its renewable energy or REC. WoW believes load migration is not a definitive reason for procuring one-year RECs, it is however, a reason for the IPA to manage the renewable products being procured. WoW says the IPA can do with renewable what it does with its energy supply, buy products of varying duration and layer them in a fashion that minimizes the likelihood of having to cancel a contract as well as fosters renewable energy development.

WoW notes that AIC suggests that the utilities provide a long-term load forecast of twelve or twenty years. According to WoW, the biggest uncertainty with the utilities' load is the migration of customers to ARES. WoW claims what drives people to move from a utility to an ARES is going to be the retail electric rate offered by the ARES. ARES are offering terms of approximately three years WoW contends that estimates of load migration are at most going to vary every three years. WoW believes a twelve or twenty year load estimate will not accurately account for load migration beyond what the utilities already provide. WoW says if the forecast is not accurate then its benefit is unclear. WoW is not supportive of a twenty year load forecast.

WoW states that a number of parties assert that higher rates paid by the utilities for renewable energy resources will increase the rates for ARES customers. Wow also states that the ACP is structured in a way that a reasonably, market savvy ARES will not have a renewable energy resource portfolio that is more costly than the utilities.

WoW asserts that the structure of the ACP allows the ARES to pay a rate comparable to what the utilities paid for their renewable energy resources. WoW believes the fact that the ACP basically equalizes the rate impact of renewable energy resources between the utilities and the ARES forces the IPA to procure products with RERF money that are comparable to those procured for the utilities. WoW suggests if the utilities are only procuring one year RECs the ACP payments would be comparable to the cost of those one year RECs and the IPA would only have enough money in the RERF to buy one year RECs.

According to WoW, the ACP and RERF are structured so that the ARES would be able to evaluate what the utilities paid for their renewable energy resources and use that as a benchmark for their own renewable procurements. WoW claims the ARES has the ability to find a lower priced renewable energy resource either by generating renewable energy themselves, buying it from an independent power producer or buying RECs. WoW contends that this gives ARES a competitive rate advantage over the utilities.

WoW notes that Staff recommends that the renewable procurement for 2012 be for one-year unbundled RECs and that a more specific proposal for longer-term contracts be developed for the next plan. WoW does not agree with the first part of Staff's recommendation, to only procure one-year RECs in 2012. WoW does agree, however, that it would be beneficial to have a more specific proposal for inviting longer term renewable contracts in 2013. WoW suggests an effective way to resolve some of the issues that continually arise would be to address them in conjunction with the solar workshops proposed for January through May 2012. WoW recommends that the IPA define the issues it would want information on so as to aid it in developing a plan for next year, such as how to effectively compare products of different types, if the procurement is segregated by type of resource, or of differing durations, or how to estimate load migration. WoW states that while these are matters that clearly can be and are addressed in the informal and formal procurement hearing processes, addressing some of these issues in a workshop may help the IPA prepare its 2013 procurement Plan.

WoW states that the 2012 Plan's proposal to procure multi-years RECs accounts for the aforementioned factors and it benefits all Illinois ratepayers by procuring longer-term products when the renewable energy resource market is long on renewable energy. To manage customer migration the IPA had proposed that the portfolio volumes would rely on the utilities low scenario projections. WoW contends that none of the facts, to the extent they present new information, challenge the viability of the multi-year REC procurement plan proposed by the IPA. WoW claims no party challenged the use of the low scenario projections or even argued that the utilities scenario estimates were invalid.

WoW asserts that last year's $1 REC prices indicate that the renewable energy resource market is over supplied. WoW says the 2012 Plan's proposal to procure multi-years RECs capitalize on that fact and buys longer-term REC products so that all Illinois ratepayers would benefit from the low-prices over time. Last year's one-year RECs were $1, so the benefit to ratepayers could only be 100 cents, but WoW claims they can get much higher in subsequent years. WoW believes it is not prudent to continually procure one-year RECs at a time when the utility can lock in low-price long-term RECs and provide price stability to the renewable energy resource costs.

WoW contends that REC prices are volatile and prices move in response to supply and demand. WoW says there are twenty states and the District of Columbia in PJM and MISO whose energy portfolio standards will require increasing amounts of renewable generation between now and 2025 and all but one allow for procurement of renewable energy resources from outside of the state, so each state will be vying for renewable energy from the same pool of sellers.

In WoW's view, $1 REC prices do not provide a sufficient revenue stream to build new renewable energy resources. Within the coming few years, WoW alleges the demand from the state energy portfolio standards will increase and so will the price of renewable energy. WoW says that in 2008, REC prices in Illinois ranged from $4 to approximately $35 and last year they were around $1. WoW also says recent market prices would seem to indicate that this would be the time to buy longer-term REC products than in the coming years, when the demand for renewable energy will be increasing. WoW believes the risk of paying higher REC prices in future procurement is much greater than the potential benefit of $1 REC prices. WoW argues that a diverse portfolio of renewable energy resource products should be purchased in the 2012 procurement.

In its Reply to Responses, WoW also states that the REC values used in its NPV analysis are not intended to be forecasted REC prices. WoW says they are example values of different dollar amounts and durations intended to demonstrate that a simple NPV comparison cannot effectively evaluate products that are subject to different market risk. WoW claims it shows that lower priced RECs are always going to have the price advantage in a simple NPV analysis in which the discount rate does not adjust to capture the change in market risk for a product of a different duration. WoW believes the accuracy of the values used in the analysis is not as important as the example they demonstrate regarding the potential flaw in the NPV analysis the IPA may have used.

In its Reply to Responses, WoW also argues that procuring a renewable energy resource portfolio of multiple products with varying duration is consistent with the principle used for procuring energy supply and is likely to yield low risk and stable prices. In addition, WoW says it is inconsistent for the laddering methodology to be used for energy supply but not renewable energy resources. WoW suggests the Commission can avoid this inconsistency by approving a Plan that procures multi-year renewable energy resource products. WoW also states that no intervenor has challenged the laddering-in principle as not striking the appropriate balance between lowest total cost over time and price stability. WoW again suggests the Commission can avoid this inconsistency by approving a Plan that procures multi-year renewable energy resource products.

In its Reply to Responses, WoW also argues that the overall policy point is that the IPA and Commission need to look at the current market conditions and future market indicators to determine what portfolio of products is going to give ratepayers environmentally sustainable electric service at the lowest total cost over time, taking into account any benefits of price stability. WoW claims the general answer is that a portfolio of renewable products will diversify the risk and has a high probability of yielding low cost, low risk and stable prices over time. In implementing the laddering principle, WoW suggests the IPA should procure longer-term products when prices are relatively low, like they are now, and purchase shorter-term products when they are either volatile or relatively high, like they were in 2008.

In its Reply to Responses, WoW also notes that Staff argues that the WoW benchmark proposal should be dismissed as a matter of law. WoW responds that it is not advocating a methodology for the authorized parties to use in determining the value or price of the benchmark, only that a benchmark be set for each product.

In reply to Exelon, WoW states the existence of the RERF does not "obviate" the need for utilities to use either multi-year or long-term renewable contracts. WoW says the renewable energy resource requirements for the ARES are set forth in Section 16-115D of the PUA. WoW contends that the existence of the RERF has no bearing or implication on what should be procured for utilities because it is structured to foster competition in Illinois. According to WoW, the Commission does not have regulatory authority over the ACP rate; it only calculates and posts the rate. In WoW's view, Exelon's argument is akin to having the Commission consider the rates ARES provide their customers in setting ComEd's and AIC's rates.

WoW argues that while the ACP/RERF mechanism doesn't guarantee a better renewable energy resource rate for ARES than what the utilities have, it does give the ARES a competitive advantage in establishing a rate that is better than what the utilities' eligible retail customers will have to pay. WoW also asserts that the ability of the current RERF to procure long-term contracts is severely limited, because the current ACP rate is primarily based on the procurement of one-year RECs. WoW says the RERF will only have enough money to procure similar products.

9. IPA's Position

The IPA states that after careful consideration of the parties' comments and objections regarding the Plan's proposal to solicit multi-year RECs, the IPA is persuaded that the 2012 Plan be revised to remove this proposal from the this year's Plan. The IPA acknowledges that customer migration, both through retail switching and municipal aggregation, could play a significant role in the variability and uncertainty of forecasted load. Further, the IPA finds that the current low cost of short-term REC prices makes it difficult at this time to support entering into long-term contracts. Finally, the use of NPV as a means of evaluating long-term REC bids becomes moot with the removal of the solicitation of long-term RECs from the Plan. The IPA continues to evaluate the parties' positions on its use, and makes no final recommendation as to its value in evaluating bids at this time.

The IPA does not foreclose the procurement of long-term RECs as an option in future procurements, and welcomes parties' comments on the inclusion of proposals that invite bids for longer-term contracts. The IPA recommends that the Commission accept the following revisions to page 53 of the Plan, as offered by Staff, with an additional edit to reflect the proposed modification.

In its Reply to Responses, the IPA indicates that it agrees with the AG's comments that the IPA should be given the discretion to conduct a procurement event for multi-year REC contracts, and accept various alternative length contracts for REC. However, the IPA further agrees with the AG that "one-year RECs might be the best option for the IPA this year, as it was last year, based on price and availability."

The IPA recommends that the Plan be revised to procure one-year REC contracts to satisfy the uncommitted portion of ComEd and AIC's renewable resources budget for the 2012-2013 period. The IPA commits that it will conduct workshops in 2012 to examine how to best solicit multi-year RECs contracts in future procurement plans.

10. AG's Position

The AG notes that a number of parties objected to the 2012 Plan proposal to purchase renewal resources because it would invite bids for renewable generation for "up to 20 years" while they believe that only short-term RECs should be procured to match the three year laddered procurement. The AG states that the 2012 Plan would invite bids for periods up to 20 years for renewable generators, allow single year as well as multi-year bids for resources. Although this would provide the IPA with maximum flexibility and choice of resources, the AG says parties object because other electricity would be purchased on a laddered three-year forward basis.

The AG recognizes that there may be a time inconsistency between the three-year general supply procurement and the option to obtain long-term renewable resources, up to 20-year term. The AG asserts, however, that the Commission has recognized the need to include long-term renewable resources in Procurement Plans. The AG believes that excluding long-term contracts for renewable resources from the 2012 Plan would contravene the policy set out by the Commission and could potentially discourage the development of the renewable resources market necessary to meet future renewable resources obligations.

According to the AG, the competing interests in low-cost electricity and the benefits of price stability and the fact that there was a recent long-term renewable resources procurement earlier this year, counsel against imposing either a long-term renewable resources mandate or a long-term renewable resources ban in this Plan. The AG believes the procurement administrator should have the flexibility to assess whether the renewable resources market contains sufficient resources, in the form of short-term RECs, bundled RECs and electricity, or long-term contracts, to support Illinois's renewable resources portfolio requirements over the coming years. The AG suggests that if there are bids for renewable resources covering more than a three-year period, and the volume and price are competitive with short-term RECs, the IPA should have the option to accept them. In the AG's view, this flexibility would enable the IPA to assess both the long-term and the short-term market, and make appropriate decisions based on actual bids.

The AG notes that other parties argue that the renewable resources obligation should be met with one-year RECs exclusively. The AG says one-year RECs might be the best option for the IPA this year, as it was last year, based on price and availability. In addition, the AG says the recent IPA long-term renewable resources procurement and the beginning of customer migration from the IPA portfolio are legitimate reasons to err on the side of caution and use short-term RECs to satisfy the renewable resources obligation. The AG insists that price should be the guiding principle in determining whether the IPA should limit its procurement to one-year RECs. If the market for short-term RECs continues to offer adequate resources to meet the Illinois renewable resources obligation at low-cost, the AG believes short-term RECs should be the preferred renewable resources for 2012.

The AG indicates that another objection to the renewable resources part of the 2012 Plan is that it establishes a "conservative" RRB for the next 20 years which will constrain and reduce large procurement of or long-term contracts for renewable resources. This Objection is based on the assertion that there is insufficient evidence to show that, at least in the AIC area, load migration is sufficiently high to justify such a large constraint on renewable resources procurement. The AG responds that it is prudent, at this early stage of customer migration, to err on the side of caution, and to base any long-term renewable resources procurement on assumptions that at worst, would obtain less renewable resources than possible for the longer term. Given the fact that there are annual procurement processes, the AG believes it is wiser to limit the size of long-term renewable resources purchases until the extent of customer migration becomes more known and settled. It is the AG's position that while the migration experience in the AIC areas may not be equivalent to that in the ComEd area, customer migration is not well developed, and it is more prudent to obtain long-term renewable resources if customer migration is less than allowed in the Plan than to have excessive long-term renewable resources obligations that either exceed the need or exceed the budget available for them.

11. Solar Alliance's Position

In its Response to Objections, the Solar Alliance notes that several parties object to the IPA's proposal to solicit bids for RECs for periods of up to 20 years. The Solar Alliance believes these objections must fail because they neglect fundamentals of renewable energy project finance, improperly equate wind RECs with SRECs, and ignore the known risks of relying solely on short-term contracts.

According to the Solar Alliance, project development is driven fundamentally by the amount of revenue required to support a project and the certainty and transparency of that revenue stream. The Solar Alliance claims that the availability of long-term contracts with reasonable terms and conditions is fundamental to a well-functioning SREC market. The Solar Alliance says with a long-term contract, project developers have a known horizon during which the revenue stream will be available to compensate for the costs of a system. The Solar Alliance contends that the availability of long-term contracts is critical to the full development of the Illinois renewable energy marketplace as envisioned by the state's RPS. Without long-term contracts, the Solar Alliance claims projects will not be built, and the RPS will suffer.

The Solar Alliance says that although some intervenors attempt to treat wind RECs and SRECs as equivalent, they are not. The Solar Alliance claims the solar carve-out requirement of the RPS will only begin with this procurement, while wind requirements have been in place for years. According to the Solar Alliance, this means that certain arguments about the availability and cost of RECs based on past procurements do not generally take solar projects and SRECs into account. The Solar Alliance says references to $1-per-REC prices and sufficient supply to meet the RPS with only short-term contracts are reflective of wind resources only. Whether wind RECs can be purchased as low as $1 per REC is not disputed, but the Solar Alliance believes this should not be used as an indicator that SRECs could be procured for such a low amount. According to the Solar Alliance, even with over-supplied SREC markets in other states, SRECs have remained much higher, with extreme low values between $50 to $75 per SREC.

The Solar Alliance believes that assertions that short-term RECs are abundantly available at sufficient volumes to satisfy the RPS rely on the premise that solar projects and the SREC market will perform similarly to wind projects and wind RECs. The Solar Alliance insists this is simply not the case. The Solar Alliance says a solar procurement based on wind project needs and REC prices is set up to fail. The Solar Alliance states that wind RECs and SRECs should be treated as two separate aspects of the renewable procurement in this and subsequent procurements. According to the Solar Alliance, previous wind results should only affect future wind procurements, just as solar results should only affect future solar procurements.

The Solar Alliance contends that long-term contracts will provide a hedge to the known risk of short-term contract prices increasing when over-supplied solar markets come into equilibrium or become under-supplied. The Solar Alliance states that historically, under-supplied solar markets support SREC prices as high as $600 to $700 per SREC. The Solar Alliance says while some markets are currently experiencing over-supply that has decreased SREC prices, each market has mechanisms in place that will drastically increase demand in the short-term, generally during the next one to three years. The Solar Alliance claims that should the IPA choose to procure solar only on short-term or one-year contracts, when this market transformation occurs, the IPA will have to buy much more expensive SRECs than would be available for long-term contracts in the 2012 procurement. The Solar Alliance alleges this is a known risk; only the exact timing of the risk is unknown. The Solar Alliance believes entering into long-term contracts now, when the markets are relatively low-cost, will provide a valuable hedge to this risk.

12. IREC's Position

In its Reply to Responses, IREC states that the ability of Illinois utilities to procure low-cost RECs in the spot market will tighten as compliance targets ramp up among the states, creating greater competition among REC purchasers. In IREC's view, RECs are important from the standpoint of renewable energy developers because they represent a value stream that factor into the decision to invest in renewable generation. For states that have chosen to institute a RPS program, IREC says the renewable attributes of generation necessarily carry a value based on the obligation that jurisdictional electricity providers must satisfy. IREC states that in this way, REC prices send signals to the market that should reflect the degree of demand for procurement. In an efficient market, this price signal will encourage the proper amount of renewables to be installed that will meet the state’s requirements. RECs are an elegant market solution to encourage new generation to be installed.

IREC believes a program to procure RECs or SRECs that focuses on short-term purchases is at odds with the long-term purpose for which RECs were created. IREC says the long-run goal of state RPS programs is to add new renewable resources to the generation mix. IREC asserts that a program that focuses on a short run availability of excess RECs may succeed in lowering costs in the current year, but it will leave participants scrambling to catch up when the spot market prices rise due to RPS-mandated increases in demand. According to IREC, price spikes, in theory, might drive the market to equilibrium, that is, spur more supply, but it does so inefficiently, creating unnecessary crisis pricing that could result in substantially higher costs for ratepayers or in public backlash against renewable policies. IREC asserts that despite this likelihood, several parties claim that short-term SREC procurement, i.e., annual, is sufficient and should be the model moving forward.

IREC believes that a short-term focus on SREC procurement creates market inefficiencies by creating boom and bust cycles. Rather than creating this cycle of fits and starts, IREC suggests that an efficient REC market should encourage sustained incremental additions of generation to reflect the statutory incremental demand. IREC claims this will avoid overcompensating renewable generators in future years, based on the wild throws of the marketplace, and avoid undercompensating potential entrants to the market. IREC also asserts that REC procurement that reflects the lifecycle of renewable generators is more likely to produce market stability and create more sustainable and consistent cycles of renewable project development.

According to IREC, this consideration is particularly relevant in the context of smaller, distributed solar systems. IREC claims smaller, distributed systems, compared to larger, utility-scale systems, do not benefit from economies of scale and may be undertaken by smaller companies or residential customers that do not have the same financial heft or sophistication as the developers of much larger projects. IREC believes a stable SREC value stream represents a bankable asset that developers of small systems can leverage to secure small project financing. Instability in SREC value will harm smaller developers and limit residential systems that rely on a constant value stream to justify building a project. IREC says these projects are likely to have difficulty competing for financing with larger project developers who are likely to have more sophisticated options at their disposal to absorb the risk of a volatile SREC market.

IREC notes that several parties claimed in objections and responses that it would be inappropriate for the Commission to approve long-term procurement of RECs because no market currently exists. IREC suggests that this obstacle is easily overcome. In IREC's view, it is not hard to imagine a well-functioning market for long-term procurement of RECs, particularly given the inevitable increase in procurement obligation mandated by law. IREC proposes long-term SREC procurement, as part of a portfolio of other products that it believes can have a beneficial and stabilizing effect on the renewable market and may insulate ratepayers from price spikes that could manifest as a result of a focus on short-term procurement of RECs.

IREC believes that procurement planning for SRECs should be based on a longer horizon and that a mix of SREC purchase options will benefit the market for distributed solar and ratepayers. IREC claims the success of an approach that utilizes long-term SREC procurement to avoid SREC volatility, however, is dependent on the load forecasts for ComEd and AIC. In the case of a low load forecast, as is used the IPA proposal to establish SREC needs, IREC contends there is a very real risk that procurement of SRECs will fall short of the annual obligation and the utility will have to procure a large number of SRECs on the spot market. IREC believes it is important to base SREC procurement on the most likely estimate of expected load, so that a long-term SREC strategy to stabilize SREC prices is not undermined by a substantial underestimation of expected load. IREC suggests a balanced approach that utilizes long-term SREC products, effectively, to stabilize SREC values to the benefit of the distributed solar market and ratepayers.

According to IREC, the value of SRECs can have a substantial impact on a customer’s decision to invest in a solar energy system. IREC says customers who install solar facilities, particularly those who install net metering systems to offset on-site load, depend on a value stream throughout the life of that facility to justify the initial expenditure. Commonly referred to as the “buyback period,” IREC says customers are more likely to invest in solar resources if they realize benefits equal to the costs of a facility within a reasonable period of time. IREC claims a predictable revenue stream from SRECs over a long period of time can significantly shorten the “buyback period” and give customers additional confidence to invest in solar resources. IREC asserts that this principle is true for larger solar systems and for distributed solar systems, which are assumed to be behind-the-meter in the IPA Plan. IREC believes just as an efficient REC market will send price signals to encourage sufficient generation to meet demand, the SREC market must send price signals that are sufficient to encourage development of solar resources to meet this legislative carve out.

IREC states that project economics for any generation project favors greater certainty of revenue streams over the life of the system. IREC believes that this is particularly true for developers of smaller systems that may not be as equipped to absorb the risk of SREC market volatility as developers of larger systems are able to accomplish through economies of scale, e.g., by using a larger corporate structure to secure better financing terms. IREC says this means that a distributed SREC procurement program should have a long-term character if it hopes to encourage investment in distributed solar resources. IREC suggests that long-term, 20-year SRECs are a critically important option for distributed solar, as this will provide the most certainty for customers considering investing in solar. IREC acknowledges that shorter-term agreements may suit different types of project developers and believes that the ultimate plan should contain a mix of SREC purchase options.

At a minimum, IREC suggests that SRECs be procured for no less than a purchase term of three years. IREC believes a three-year term is long enough to provide generators and ratepayers some protection against SREC price swings in the spot market and also is consistent with the three-year horizon used in the Plan to project capacity needs.

IREC proposes that a portfolio of contract length options for SRECs, of mostly 10 year and 20 year contracts, could help stabilize SREC prices and allow for market growth. IREC believes maintaining a diverse portfolio of contract lengths may allow utilities to hedge against volatile spot market costs, as states like New Jersey have faced in implementing their SREC program.

IREC suggests that gaining experience with long-term SREC procurement will better inform IPA designs for long-term REC procurement in its 2013 Plan, including harmonizing load forecasts to ensure that the proper amount of long-term SRECs are procured. IREC believes that load forecast assumptions should be consistent throughout the IPA plan, including the procurement of SRECs. IREC says because actual load growth does not necessarily follow projections, gaining experience with designing a portfolio of contract lengths in meeting distributed SREC procurement targets might highlight the risks involved with relying on low load projections for SREC and REC procurement.

IREC acknowledges that there is a fair degree of uncertainty facing load projections, including load migration concerns and the speed of economic recovery, but says on the chance that actual load exceeds the low forecast, or meets the expected forecast, the utilities will be faced with procuring significantly more SRECs on an annual basis. IREC believes SREC procurement planning should follow the average or expected forecast, not the low forecast. IREC says the average forecast is otherwise relied on throughout the IPA Plan to ensure adequate procurement.

According to IREC, the difference between ComEd's low forecast and expected forecast is dramatic. IREC says if a pilot program were devised to procure 100% of all SRECs through 20 year and 10 year contracts, all unexpected load growth would result in under-procurement of those longer-term products and create greater reliance on short-term products. IREC also says if ComEd's actual load meets or exceeds the expected forecast, ComEd's SREC procurement obligation would increase by nearly 50%. ComEd would have to procure that amount on the spot market, through one-year SRECs, leaving ratepayers and customers exposed to volatility. IREC urges the Commission to encourage or require the IPA workshops to consider this element of program design and to utilize realistic forecasts for SREC procurement to ensure that a long-term strategy can deliver optimal benefits.

IREC notes the IPA expresses the concern that use of the average load forecasts could lead to over-procurement of SRECs, but that would not be likely to cause a problem. IREC says if the IPA needs fewer SRECs than expected due to low loads, that means that other suppliers will have higher loads than expected, and need SRECs. IREC indicates the IPA would have excess available for sale. On the other hand, use of the low load forecast could lead to substantial under-procurement of SRECs in the event that the average or the high load forecasts are realized. IREC complains that without explanation, it seems that the IPA Plan and various parties consider nothing more than the average load forecast to be realized, though presumably the high and low forecasts are equally probable.

IREC suggests that proceeding with a pilot program in 2012 for distributed SRECs and including a fully-developed program in the 2013 Plan presents very low risk to consumers of over-procurement. IREC asserts that because the solar carve out continues to escalate, the amount of long-term SRECs procured in 2013 would be miniscule compared the requirements in 2020, even under a low forecast scenario.

13. Commission Conclusion

Similar to its proposal with regard to soliciting proposals for electricity from a clean coal facility, the IPA initially proposed, then withdrew its proposal to solicit long-term renewables as a part of the 2012 Plan. This issue received a large amount of discussion as laid out above and which will not be repeated in this conclusion.

It appears that those opposed to the proposed acquisition of long-term RECs have raised legitimate concerns. Staff for example identifies several problems with the manner in which the IPA planned to compare bids with differing terms. While the Commission is open to considering long-term RECs for inclusion in future procurement Plans, the Commission finds that given the current market conditions, eligible retail customers are likely to benefit from the acquisition of one-year RECs. For purposes of the 2012 Plan, the Commission concludes that one-year RECs should be included and long-term RECs should not be included.

C. Solar RECs

1. ComEd's Position

The IPA proposes to require the procurement of no less than 25% of the solar renewable energy procurement obligation from small and mid-size distributed systems in Illinois. ComEd supports the development of efficient and cost-effective solar resources, but claims the IPA's proposal is inconsistent with both the IPA Act and the PUA, and will result in consumers paying unreasonably high prices for renewables.

ComEd says Section 1-75(c)(1) of the IPA Act creates a special statutory preference for solar renewable energy resources, provided they are available and cost-effective. ComEd contends that the language is precise and does not provide for any additional carve-out or preference for solar renewable energy resources based on the size of the system that captures the solar energy or whether the system is "distributed" (connects to the distribution system).

ComEd also contends that nothing in either the IPA Act or the PUA purports to give the IPA or the Commission any authority to create any preferences on their own. ComEd asserts that where preferences are authorized, the IPA Act spells them out. According to ComEd, the preferences for wind RECs, solar RECS, Illinois resources (a preference that expired in June 2011), and resources in Illinois and adjoining states (still in effect) are spelled out. ComEd argues that if the General Assembly had intended there to be a preference for distributed SRECs, that preference would appear in the Act they passed.

According to ComEd, the PUA provides for the procurement of renewables through a RFP competitive bidding process in which the selection of winning bids is made "on the basis of price." ComEd says that process ensures that procurements satisfy the "lowest total cost over time" test. ComEd believes the IPA's proposal to select some of the winning bids on the basis of the size of their solar system, or because they are "distributed," is inconsistent with the IPA Act and the PUA and should be rejected.

In ComEd's view, the IPA's proposal would also effectively rescind the SREC preference that the General Assembly did adopt. The IPA Act grants a statutory preference to all solar generation owners, giving them alone access to a prescribed portion of the renewables requirements. ComEd says the IPA would entirely disallow larger solar generation owners from bidding on a significant portion of this resource that was legislatively apportioned to all solar generation owners. In ComEd's view, besides being wholly unfair to the larger solar generation owners who are entitled to the full benefit of their legislatively-granted preference, this is illegal. According to ComEd, whatever their arguments are when the law is silent, the IPA cannot argue that it has the authority to take away legislatively granted preferences from owners to whom those preferences are expressly granted.

ComEd also maintains that the proposal to procure SRECs from facilities located in Illinois is also inconsistent with the IPA Act. ComEd notes that the preference in the IPA Act for procuring renewables from facilities located in Illinois expired on June 1, 2011. Currently, the statutory preference is for facilities located in Illinois and adjoining states. ComEd believes the IPA's proposal to nonetheless extend a preference to facilities located in Illinois violates that law.

The Plan describes two different types of distributed SREC procurement programs that the IPA intends to consider. ComEd argues that both of these programs will raise costs to consumers by limiting participation in the bidding process. According to ComEd, reducing the competitiveness of the auction process, either by holding separate auctions or awarding some bidders a contract even if they do not participate in the auction, as in the "standard contract offer program," will likely raise the average price paid for the resulting SRECs. ComEd says this conclusion follows without even taking into account the temptation for bidders in such a process, who know they are facing fewer competitors, to raise their bids above what they would have been in a fully competitive auction.

ComEd says the first type of program that the IPA intends to implement is a fixed-price, long-term, standard offer contract program in which an initial contract price is based on the auction clearing prices for SRECs from the IPA's Spring 2012 auction. ComEd indicates that, apparently, these prices are then to be adjusted annually in order to track the market ("Standard Offer Program"). ComEd insists this proposal is illegal, reduces competition, allows non-participants to "win" an auction-based contract, and will drive up prices. ComEd also claims it will also be very impractical and costly to implement and is inconsistent with the law in several other ways.

The PUA provides for the use of a RFP competitive procurement process in which the winning bidders are selected on the basis of price. ComEd says the standard Offer Program does not include the use of a competitive process at all. Instead, ComEd indicates that it appears that the IPA intends to award contracts to particular small and mid-sized owners on the basis of unspecified criteria. ComEd complains that whatever those criteria are, price is not one of them, as the IPA proposes to pay all such winners the same fixed price for their SRECs.

ComEd also complains that this program unfairly allows eligible market participants multiple opportunities to be awarded a contract, at many different times. ComEd says other market participants are allowed only one opportunity to bid and, perhaps even more importantly, cannot adjust their bids over time as market conditions change or as they learn more about the prevailing price. Standardized procurement works to get the lowest price because all participants have the same opportunity to bid using the same market costs at the same point in time. ComEd suggests that when some participants know that they have additional opportunities to win, even if they do not bid the lowest cost the first time, the process does not generate the lowest cost possible for consumers.

According to ComEd, without the use of a competitive procurement process, the IPA cannot demonstrate that its proposal to meet the SREC preference in the law will result in “the lowest total cost over time” for electric service. ComEd says the IPA makes no attempt to make that showing. Since the Commission must apply “the lowest total cost over time” standard in considering whether to approve a procurement Plan, ComEd believes it cannot approve the proposed Standard Offer Program.

ComEd says the Standard Offer Program apparently would require it to enter into agreements directly with each supplier. These suppliers could own generation as small as 2 or 3 kW, while one standard SREC is 1 MWh. Thus, ComEd says it will have to enter into agreements with a very large number of suppliers, many of whom will be residential customers who are undoubtedly unfamiliar with contracts and performance obligations thereunder. ComEd is concerned this will dramatically increase its billing, enforcement, and compliance costs, not to mention the downstream impact on regulators called upon to resolve resulting disputes. ComEd claims operating costs will rise, new and additional information systems will have to be developed and installed, and employee time and effort will be diverted to track and monitor compliance for this large number of very small suppliers. The bottom line, ComEd asserts, is still more costs passed through to consumers.

The second type of program that the IPA intends to consider is an auction for long-term contracts in which participation is limited to aggregators of SRECs from small and mid-sized distributed solar systems in Illinois (“Aggregator Program”). ComEd insists this program is illegal and cannot meet the lowest total cost over time standard.

While the Aggregator Program does involve the use of a competitive procurement process, that process is limited to aggregators of small and midsized systems. Suppliers with large solar systems will not be allowed to participate, even if their costs are lower or they would offer a lower price. ComEd argues that if one limits the number of potential bidders in a competitive procurement process, especially by excluding an entire class of bidders ahead of time, the price obtained is going to go up. ComEd claims this is particularly the case where, as here, the excluded participants are likely the low-cost providers.

According to ComEd, the installed costs of solar generation systems exhibit tremendous economies of scale. ComEd says systems less than 2kW averaged around $9.8/W in 2010, while systems greater than 1,000 kW averaged $5.2/W, approximately half the unit costs. ComEd claims even larger, utility-scale systems, currently average $3.8 to $4.4/W. ComEd believes that excluding suppliers with dramatically lower costs from participating in the Aggregator Program assures higher winning bids. ComEd contends that such a result not only cannot be shown to satisfy the PUA’s lowest total cost over time standard, it will demonstrably result in exactly the opposite result.

In addition to the higher resource supply costs and the higher start-up and ongoing costs of administering and managing contracts with many small counter-parties, ComEd also expresses concern that this proposal will impose the additional cost associated with holding additional procurement events with different bidders and different terms. ComEd says that last year, the cost of procuring RECs in ComEd's single procurement event was over $200,000. ComEd claims that by doubling the number of procurement events, perhaps tripling them with the "standard offer contract program," REC related procurement costs will likely be substantially higher than in previous years.

ComEd says the PUA requires the IPA to submit a Plan to procure resources to the Commission for review. It requires the Commission to assess that Plan and make specific findings without which it cannot be approved. ComEd believes that significant portions of the IPA's SREC set-aside program are not in a form that can be assessed and approved. ComEd complains that the Plan does not specify what programs will be used, when they will be used, or even the details of how they will be structured and conducted. Rather than include those features in the Plan, as required, ComEd says the IPA instead proposes a process through which the IPA hopes to flesh out its Plan.

ComEd says it understands that this proposal is in its infancy, noting it was not included in the original Draft Plan circulated by the IPA and came into being only recently, apparently in response to a series of requests in the comment process for some sort of small supplier preference that the General Assembly had not granted. ComEd says it has pointed out a number of fundamental flaws in the IPA's proposal, but the proposal itself is simply too insufficiently developed to be approved. If the IPA wishes to hold workshops to discuss this concept, as the Plan proposes, ComEd indicates it would gladly participate. ComEd insists that type of exploratory workshop process must be used to help the IPA develop a proposed plan, not be the proposed plan.

ComEd states that the IPA's Aggregator Program proposal incorporates the concept of selecting winning bidders on the basis of a competitive RFP procurement process in which winning bidders would be selected on the basis of price. This approach addresses many of the concerns that ComEd has with the SREC proposal. ComEd believes the remaining concerns can be addressed by a simple modification to the proposal. Instead of conducting a separate RFP for aggregators, ComEd suggests the IPA could conduct a single RFP in which the aggregators bid and compete against all other SREC suppliers and all other REC providers. ComEd says since the IPA's proposal already would require the aggregators to incur the cost of participating in a competitive procurement process, the participation in the broader REC RFP process should not impose much, if any, additional costs on the aggregators. ComEd suggests aggregators would then be able to aggregate as small an amount as 1 MWh of load and bid that into the RFP. In ComEd's view, such an approach would remedy the legal impediments to the Commission's ability to approve the IPA's SREC proposal, and should be considered by the IPA and the Commission.

In its Response to Objections, ComEd notes that the Solar Alliance's Objections includes securitization by the IPA of the ACP and use it as a financing mechanism.

Among other things, ComEd believes such a proposal is vague and is neither practical nor lawful.

ComEd believes the Solar Alliance's proposal is impractical because the amount of ACP that is collected annually varies. ComEd states that both factors determining the amount of ACP collected in any year, the ACP rate ($/MWh) and the volume (MWh) subject to the ACP, are variable. ComEd says the ACP rate is linked to the amount paid by ComEd's Eligible Retail Customers for renewable energy resources, which varies with the results of each procurement event. ComEd also says volume varies both as the load served under ComEd's real time pricing tariffs varies and as the load served by ARES varies. ComEd asserts that to be securitized, a financial payment stream needs to be extremely well defined so the purchasers of the securitized debt can be assured of recovery. ComEd contends that here, there is no fixed and known stream of revenues to be converted into a marketable security. If the Solar Alliance's proposal were to be accepted, ComEd says a loan would be taken out and the proceeds used to pay suppliers for current RECs.

ComEd also believes the securitization proposal is also inconsistent with the IPA Act. ComEd insists that nowhere in the IPA Act is the IPA empowered to issue securities backed by streams of future utility revenues. ComEd says the Illinois General Assembly knows very well how to authorize securitization, and it did not do it here. ComEd states that the Illinois General Assembly specifically directed that all ACPs by an ARES shall be deposited in the IPA RERF and used to purchase renewable energy credits, in accordance with Section 1-56 of the IPA Act. ComEd believes this language provides no room for the alternative securitization proposal made by the Solar Alliance.

ComEd recommends that the Commission decline to accept the Solar Alliance's request that the Commission to mandate, in advance, that the IPA use a specific benchmark that the Solar Alliance favors. ComEd says the benchmarks are there to protect consumers from noncompetitive bids. ComEd claims their purpose is to force bidders to offer their best price even if they believe they might have pricing power due to limited supply options. ComEd states that the benchmarks are determined by the IPA, Procurement Administrator, Procurement Monitor, and Staff, subject to review and approval by the Commission. ComEd claims the benchmarks are deliberately kept confidential so that the bidders cannot develop counter-strategies to defeat their purpose. ComEd believes this is a far better process for consumers than allowing a coalition of bidders to select its own benchmark.

ComEd also says the pricing curve is also kept confidential to protect customers by minimizing potential pricing power. ComEd again asserts that this is done to keep prices low by ensuring a totally competitive process. ComEd believes the forward price curve should remain confidential prior to the procurement event.

ComEd believes that the fact that a carve out for DG Solar, whether by setting a floor on the winning DG Solar bids in a single auction or by holding a second auction, will increase prices for customers is one reason why it is illegal. ComEd argues that the law requires the Commission and the IPA to approve only procurement plans that propose to provide the lowest total cost energy over time, consistent with the portfolio standards and limitations in the law. ComEd believes this can be achieved only by holding a single, combined procurement event that could incorporate other techniques, such as those ComEd proposed to ensure that DG Solar facilities have a fair, but not unequal, opportunity to participate. ComEd contends that the Solar Alliance's comments remove any doubt about why the Commission cannot accept Solar Alliance's proposal.

ComEd says it is unclear what the Solar Alliance wants changed through its Objection D. If the Solar Alliance is arguing that the three day signing period for winning bidders is too short and should be extended to at least six months, ComEd believes that recommendation should be rejected. ComEd asserts that keeping a bid open for an extended period creates risk for bidders and purchasers alike. ComEd believes that if a bidder submits a firm bid and wins, it must be committed to signing the contract quickly after selection. Otherwise, ComEd says customers would bear the risk that market prices could increase over the next six months and a winning bidder might decide they can find a better deal elsewhere or become unable to sign the contract. ComEd notes that this is essentially the same reason that Constellation argues that the contract approval process must be streamlined. According to ComEd, while Constellation wants to streamline an already rapid process, the Solar Alliance appears to propose extending it approximately 60-fold.

ComEd says if Objection D is about the timing of deliveries, i.e., is an effort to argue that, while a long-term contract can be signed quickly, deliveries for a new plant should be allowed to start up to twelve months later, then ComEd suggests that issue can be addressed in the terms of the long-term contract. ComEd does not believe it is a reason to extend the contract process.

In Objection E, the Solar Alliance recommends that the Commission require the use of the expected rather than low load case for multi-year RECs. According to ComEd, given the high degree of switching risk in the market, such a recommendation could easily lead to an over-procurement of RECs which would impose an effective stranded cost on remaining customers. ComEd believes the Commission should reject changes to this aspect of the IPA Plan.

In its Reply to Responses, ComEd says other parties, including IREC, Solar Initiative, ISEA, ELPC, and the Solar Alliance, continue to urge discriminatory subsidies, carve outs, and procurement procedures designed to favor their particular flavor of solar energy at the expense not only of consumers but also of other competitive renewable energy vendors. According to ComEd, the key fact is undisputed, even by small solar boosters: In the words of IREC, "it is true that smaller DG projects do not enjoy the economies of scale of larger or utility-scale projects." ComEd argues that forcing the procurement process to purchase distributed solar resources that are higher cost than other solar resources does not help achieve the solar portfolio standards and inescapably increases costs.

2. AIC's Position

AIC expresses concern that the IPA's proposal contains few details regarding the term and quantity of SRECs to be solicited and AIC finds it difficult to provide detailed comment. AIC references Section 16-111.5(b)(3)(iv) of the PUA which requires the proposed term structure and mix of products to be provided in the Plan. That being said, AIC offers the following general comments in order to facilitate discussion in the future. First, the IPA proposes a procurement event by December 2012. AIC notes that this procurement event would occur after the commencement of the 2012 Plan year and AIC believes it would be more appropriate for the 2013 Plan as opposed to the 2012 Plan. AIC suggests the IPA could proceed with workshops during January 2012 through May 2012. AIC believes workshops would enhance the development of a more detailed proposal which could be included in the 2013 Plan. AIC says that SB 1652 has a proposal whereby the IPA would solicit RECs from "distributed renewable energy generation devices" and in targeted quantities that commence June 2013 and increase over time. AIC says that while SB 1652 has been vetoed by the Governor, the IPA acknowledges in its Plan that legislative efforts to override the veto have been announced. AIC recommends the IPA consider the solicitation associated with SB 1652 when developing any proposed solicitations associated with future Plans.

AIC suggests the Commission should order that if the IPA intends to include distribute solar RECs in its Plan, it should do so in the 2013 Plan as opposed to the 2012 Plan, and any such proposal should include specific terms regarding the term, structure and type of products desired, as well as a consideration of the impact of any solicitations associated with SB 1652 should it be enacted.

In its Response to Objections, AIC notes that the Solar Alliance urges the IPA to modify its procurement plan for SRECs by developing a long-term strategy that incorporates contracts of ten years, and that includes the securitization by the IPA of the ACP and uses it as a financing mechanism. Regarding the proposal to purchase SRECs for ten years, AIC reiterates its position that the IPA should solicit RECs, including SRECs, only for the prompt year. Regarding the proposal to use the ACP as a financing mechanism, AIC notes the lack of detail and recommends this proposal therefore be rejected. AIC asserts that securitization is a complicated process that effectively guarantees a revenue stream of sorts. AIC believes that doing so would not preclude Solar Alliance from discussing the issue again during workshops associated with future procurement Plans.

AIC also notes that the Solar Alliance advocates a solicitation of distributed SRECs for no less than 25% of the solar renewable energy procurement obligation. AIC reiterates its recommendation that the IPA hold workshops to address the propriety of a solicitation of this nature, but if the IPA desires to solicit distributed SRECs, such a proposal should be in the 2013 Plan and include more specifics while also considering the impact of solicitations pondered under SB 1652 should it be enacted.

The Solar Alliance also recommends a revision to the IPA proposal to create a 20 year RRB and further comments on the IPA proposal for evaluating long-term bids. AIC once again reiterates its recommendation that the IPA solicits RECs only for the prompt year, including SRECs, and at the target quantities and budget cap provided in the Plan. However, if the Commission disagrees and determines that the IPA proposal for long-term RECs should be pursued, AIC requests the Commission require the Plan include a long-term forecast and clarify whether this should be for 12 or 20 years. AIC says this forecast should include yearly targets and budgets. As AIC previously suggested, a forecast could be created by the IPA or the IPA could request AIC to create such a forecast, and the IPA can then review and affirm.

In its Reply to Responses, AIC notes that the IPA recommends that the Commission remove the distributed SRECs proposal from the current Plan and desires to have workshops in January 2012 through May 2012 which will review the issues raised by parties. The IPA will then determine whether distributed SRECs should be included in future Plans. AIC agrees with the IPA recommendation.

3. Staff's Position

According to Staff, the IPA Plan fails to explain how its procurements will yield carve-out consistent contracts for solar and wind. Staff expresses concern that the IPA Plan does not provide sufficient detail about how the proposed process would work in practice. Staff believes this is particularly true of the "cryptic" assertion that the IPA will “[c]onduct procurements that yield carve-out consistent contracts for solar and wind.” In this regard, Staff notes that in the 2010 procurement of the LTPPAs, the wind and solar carve-outs were implemented in the manner described in detail in Appendix 5 - Evaluation Process of the RFP issued by National Economic Research Associates, Inc. ("NERA").

With respect to the solar and wind carve-outs, Staff recommends that the Commission approve the above process from Appendix 5 – Evaluation Process of the RFP issued by NERA in 2010.

Staff believes the IPA’s objective to procure SRECs from owners and aggregators of distributed solar photo-voltaic resources is laudable, but the IPA’s proposed implementation process should be amended. Given the recent introduction of a solar photovoltaic carve-out in the IPA Act, the relatively high cost of solar resources and SRECs, and the actual and potential growth of DG Solar resources, Staff supports the IPA’s objective to procure SRECs from owners and aggregators of distributed solar photovoltaic resources. Furthermore, if a legal mechanism can be developed and cost-effectively implemented for DG Solar resources, Staff believes it may be a useful template for procuring non-solar RECs from owners of other distributed renewable resources (e.g., small-scale wind turbines). In this context, Staff defines a cost-effective mechanism as one that reduces the cost of satisfying the goals of Illinois’ RPS or brings the IPA and the utilities closer to meeting those goals.

Staff believes the current IPA proposal is too underdeveloped at this point. Staff is convinced that more work must be done to improve upon the IPA's two basic approaches. For this reason, Staff supports the IPA's planned workshop process for informing future IPA plans. In addition, Staff would support a relatively modest pilot program which could be introduced on a shorter time scale.

Staff also believes certain aspects of the IPA's DG Solar plans should be rejected by the Commission and changed in some respects. Staff believes that the IPA's proposal to implement two new SREC procurement programs, which it says are only vaguely described in the Plan, after workshops but without any further Commission oversight, is too open-ended, and should be rejected. Staff complains that the Plan describes these two new programs in only three sentences, but seeks Commission approval to commit an unspecified quantity of utility and ratepayers funds to pay for the resulting purchases of SRECs. Staff recommends that the Commission withhold such approval until it is comfortable with whatever procurement programs the IPA devises. For its own part, Staff is far from comfortable with the second of the IPA's two programs, and Staff needs answers to several questions before it can make any recommendations on the other program. Hence, Staff recommends that the Commission reject the IPA proposal to implement its two SREC procurement programs. Nevertheless, Staff also recommends that the IPA be encouraged to hold workshops and take others steps to design a fully thought-out program for Commission review in a future plan proceeding.

Staff notes that the IPA proposed SREC procurement programs is to implement a separate "auction for long-term SREC contracts in which participation is limited to aggregators of SRECs from multiple small and mid-size distributed solar systems in Illinois." Staff is not opposed to allowing aggregators of SRECs to participate in a procurement program. However, Staff believes holding an "auction" or an RFP process in a manner consistent with the RFP process described in Section 16-111.5 of the PUA is an expensive affair. Staff claims it is expensive regardless of how many bidders show up or how many SRECs are purchased through the RFP. Staff emphasizes that the total SRECs to be purchased are a small fraction of the total RECs that need to be purchased, and that aggregators of small-scale solar are probably going to constitute a small fraction of that. Staff suggests that we cannot really expect that the most cost-effective way to include such aggregators is to hold a special RFP just for them. Staff also suggests that the IPA has not justified that. Staff also says that the IPA has not presented any rough estimates of what that would cost, and what it would cost per SREC. Thus, if the Commission approves any distributed SREC procurement programs in this proceeding, Staff strongly recommends that it not be the IPA's proposed aggregator-only auction.

With regard to the IPA's proposal for workshops regarding the distributed SREC procurement program, Staff proposes additional topics. Staff says there are characteristics unique to distributed SREC suppliers versus other REC suppliers. In light of those unique characteristics, Staff suggests the IPA's current overarching credit requirement provision for REC contracts may not be appropriate for distributed REC suppliers. Staff says balancing the risk between suppliers and utilities in a manner that minimizes cost to ratepayers is a critical aspect of designing a distributed SREC procurement program that benefits ratepayers. Therefore, Staff recommends adding “Credit and Security Requirements for SREC Suppliers” to the list of major program design features and other issues that the IPA Plan plans for its SREC workshops in 2012.

Staff also believes the SREC workshops should address whether eligibility will be limited to distributed solar photovoltaics ("PV") facilities (a) within the buying utility’s service territory, (b) within Illinois, (c) within either Illinois or a state that adjoins Illinois, or (d) elsewhere. Staff also suggests that the SREC workshops should address the portion of the REC spending limit that would be dedicated to acquiring SRECs from distributed solar resources. According to Staff, an on-going issue with the IPA’s various proposals for conducting multiple procurements for the same planning years, or for overlapping planning years, is how to allocate the available funds. Staff says the IPA seemingly attempted to tackle that issue in this year’s Plan, but only in relation to what the IPA characterizes as the “Primary Renewable Energy Resource Measures.” While the Plan is still short on details of how the IPA will allocate funds between procurements for the same and overlapping planning years, Staff says it is completely silent on the share to be allocated to its two new distributed solar programs. In Staff’s view, the budget is a key component of a spending plan. Hence, even if all the other details were laid out, Staff would recommend against approval of a plan unless the allocation of available funds is specified and logically supported.

In its Response to Objections, Staff notes that several parties offer recommendations for the construction of price benchmarks. Staff urges the Commission to dismiss these recommendations as a matter of law. According to Staff, Section 16-111.5(c)(1)) the PUA clearly provides that “The procurement administrator shall . . . develop benchmarks” and that “these benchmarks shall be submitted to the Commission for review and approval on a confidential basis.” Furthermore, pursuant to Section 16-111.5(e)(3)), Staff says the Procurement Administrator shall perform this task “in consultation with the Commission staff, Agency staff, and the procurement monitor.” Staff insists that the statute places the benchmarks used for IPA procurements outside public hearings and limits the authorized parties be involved in the construction of those benchmarks. Staff believes those parties (like Staff and the IPA) are barred by Section 16-111.5 from discussing them. Staff asserts that if it and the IPA were to enter into a public debate with Comverge, Wind on the Wires, and the Solar Alliance, on the merits of the latter three organizations’ benchmark proposals, this could reveal much about the benchmarks ultimately adopted (even if the Commission were to reject the intervenors’ proposals).

In its Reply to Responses, Staff indicates that it disagrees with ComEd that utilizing two distinct processes to acquire RECs would necessarily increase the total cost of complying with the State’s RPS. Whether buying or selling, Staff argues that minimizing cost or maximizing revenue is not always achieved by forcing all the sellers or all the buyers to the same venue. Staff claims the list of such exceptions to ComEd’s rule would be endless. In the case of RECs, Staff says relying on one RFP may enhance competition within that one RFP, but it may also leave the utility isolated from a non-negligible segment of potential vendors. Staff adds that the impact of that isolation may dominate, resulting in a net increase in costs relative to a more global strategy.

Staff indicates it has not decided what global strategy would be most likely to minimize costs for the utilities, subject to the constraints of the law. Staff believes that is what the IPA's proposed workshop process might help illuminate. However, Staff is interested in exploring the potential for acquiring RECs through one or more standard offers prior to the annual RFPs for RECs. Staff asserts the standard offer rates for RECs could be adjusted periodically with the goal of reducing the total cost of acquiring RECs. According to Staff, the rates would be connected to winning bid prices in the annual RFP, in some way, in an attempt to balance the additional costs generated by the standard offer against the reduced costs of the RFP.

Staff believes the Solar Alliance's position that SREC need not be procured at least cost must be rejected. The Solar Alliance correctly notes that RECs and SRECs must be purchased in the quantities specified in the IPA Act, as long as it is "cost effective" to do so, and nobody in this proceeding has suggested otherwise. Staff states that the cost effectiveness test in this context is that the purchase may not cause retail rates to increase by more than a specified percentage. Staff claims that since the inception of the IPA Act, the Commission has been approving and Procurement Administrators have been implementing Plans, all of which have faithfully employed this cost effectiveness test. According to Staff, the Solar Alliance essentially argues that, as long as the cost effectiveness test is met, cost is irrelevant. In Staff's view, this conclusion by the Solar Alliance is supported by neither the IPA Act, the PUA, past Plans approved by the Commission, nor common sense.

Staff states that procurement Plans must include not just energy and power resources, but also renewable resources, and the standards required for such Plans, including the renewable resource component of such Plans, include ensuring adequate, reliable, affordable, efficient, and environmentally sustainable electric service at the lowest total cost over time, taking into account any benefits of price stability. Staff argues that the additional requirements of Section 1-75(c) of the IPA Act do not completely nullify the more general objectives and standards of the IPA Act; they merely authorize exceptions and provide further clarification. More specifically, Staff contends that Section 1-75(c) does not authorize the IPA to spend more toward satisfying the solar carve-out than is demanded by the market for solar RECs; rather Section 1-75(c) merely requires that the IPA spend more than the market price of conventional energy supply, if necessary, to satisfy the carve-out.

Staff also argues that Section 16-101A of the PUA reinforces the notion that procurement of renewable resources is intended and expected to reduce costs. Staff insists that this contrasts sharply with the Solar Alliance's perspective on the cost of solar power.

Staff asserts that procuring renewable resources at the lowest cost possible has been either explicit or implicit in every procurement Plan approved by the Commission to date. Staff says the initial Plans, filed by AIC and ComEd in 2007, included flowcharts for choosing winning bids of REC suppliers. Staff adds that these flowcharts explicitly described how all the requirements and preferences specified in the IPA Act would be taken into account. According to Staff, with some modifications, the Commission adopted these procedures, and no party has ever sought to materially alter them until now. Staff claims these procedures start with a straight-forward least-cost selection of bids, starting with the lowest-priced bid, and then moving to higher-priced bids, until either the spending limit is reached or the overall REC target quantity has been selected. The next step of the process is geared toward satisfying the resource-type requirements of the RPS (i.e., 75% wind and, from 2012 onward, certain percentage requirements for solar photovoltaic resources). To date, Staff says this step has involved substituting out of the portfolio less expensive non-wind resources, and substituting in more expensive wind resources, until the spending limit is reached or the 75% wind requirement is met. Staff states that these substitutions are always the least-costly substitutions needed to increase the wind percentage. That is, the highest-priced non-wind resource that made it into the portfolio during the first step is replaced with the lowest-priced wind resource that did not make it into the portfolio during the first step. Then the next highest-priced non-wind resource that made it into the portfolio during the first step is replaced with the next lowest-priced wind resource that did not make it into the portfolio during the first step.

According to Staff, while costs increase in order to satisfy the 75% wind requirement, they increase by the minimum amount possible, given the bids received. Staff proposes, and no parties have objected, to employ the same least-cost principle for the IPA Act's solar photovoltaic preference. Staff complains that the Solar Alliance would have the Commission abandon this practice in favor of providing an additional preference to distributed resources, for which the IPA Act extends no preference.

4. Exelon's Position

The IPA proposes to require the procurement of no less than 25% of the solar renewable energy procurement obligation from small and mid-size DG Solar in Illinois. Exelon opposes this proposal because it is inconsistent with the IPA Act and lacks the appropriate detail necessary to evaluate it fully. While Exelon opposes the DG Solar proposal in this docket, Exelon believes it is worth exploring proposals for the procurement of distributed generation that are in the best interest of consumers and consistent with the IPA's legal authority, to include in future plans.

Exelon states that Section 1-75(c)(1) of the IPA Act creates a special statutory preference for solar renewable energy resources, provided they are cost-effective, but does not provide a carve-out for certain solar based on size or the voltage level at which they interconnect. According to Exelon, nowhere does the IPA Act authorize the IPA to tailor its solar procurement practices based on size or interconnection voltage level. Exelon argues that where the General Assembly desired such tailoring, it specifically provided for it. Exelon contends that because the General Assembly directly and intentionally created a number of specific carve-outs, it follows that on subjects where the General Assembly was silent, the IPA should not presume authority to create additional carve-outs. In Exelon's view, the inclusion by the IPA of the DG Solar carve-out should be rejected as unauthorized by statute.

Even if the DG Solar proposal were consistent with the IPA Act, Exelon believes the Commission should reject it because it lacks detail necessary to explain its function and implementation. Exelon asserts that the Plan does not explain how the DG Solar procurement will be structured, conducted, or executed but rather proposes to resolve those issues through a series of workshops after the Commission approves the Plan. Exelon asserts that without fully vetting the DG Solar proposal before the Commission and subjecting it to the scrutiny of this docketed proceeding, the IPA proposes that the Commission essentially provide it carte blanche to craft a plan after holding workshops. Rather than approve this hastily-assembled plan, Exelon believes the Commission should reject the DG Solar proposal in this procurement docket and require the IPA to examine the issue more fully through future procurement dockets.

Even though Exelon opposes the inclusion of DG Solar procurement in this Plan, Exelon acknowledges that distributed generation may provide numerous consumer benefits. Exelon says that distributed generation can reduce the need for new transmission lines, reduce line losses, reduce the need for distribution upgrades, and enhance distribution system performance. Exelon adds that distributed generation can help protect appliances by providing improved power quality that defends against surges and sags. Exelon also says that distributed generation has a significantly lower environmental footprint than other forms of renewable generation.

Exelon says it does not oppose a thorough, reasoned investigation of the possible benefits of distributed generation. In this proceeding, however, Exelon does oppose the late inclusion of the DG Solar carve-out. Exelon insists this carve-out is not permitted by statute, nor has the IPA provided details about how the carve-out will be implemented. Because of these deficiencies, Exelon believes the Commission should reject the IPA’s DG Solar proposal in its Plan. Exelon says it would support holding additional workshops to explore the benefits of distributed generation and potential impacts on ratepayers and the competitive auction process to be considered in future plans.

5. ICEA's Position

The IPA includes a proposal in the Plan to procure no less than 25% of the solar renewable energy procurement obligation from small and mid-size distributed solar systems in Illinois. ICEA argues that this specific proposal is inconsistent with the IPA Act, is devoid of necessary detail, and may increase the costs paid for RECs and therefore the ACP. For all those reasons, ICEA believes this proposal should be denied. ICEA says it may support other appropriately designed SREC plans that achieve specific solar goals while maintaining the tenets of a competitive retail market as part of future collaborative discussions on this matter.

According to ICEA, the IPA Act provides a statutory preference for all solar resources generally, but does not provide a carve-out for specific solar programs based on size or interconnection status (i.e., connected to distribution vs. transmission system). ICEA says the IPA Act further requires that all renewable energy resources procured be “cost-effective” based on established benchmarks. ICEA believes there is no legal authority for the IPA to select winning SRECs on the basis of size or interconnection status instead of price. ICEA also believes the proposal to procure SRECs from Illinois-based facilities is illegal since the in-state preference for renewable resources expired on June 1, 2011.

The ICEA believes this DG Solar proposal lacks sufficient detail to be approved by the Commission. ICEA complains that rather than including the necessary detail upfront about how the new procurement will be structured, conducted, and executed, the IPA proposes to finalize these critical details through workshops after the proposal is already approved. ICEA asserts that this is putting the proverbial cart before the horse and should not be permitted by the Commission. ICEA contends that there is no reason to rush the approval of a specific DG Solar procurement before all options for the best outcome have been fully vetted. ICEA says the solar preference that exists under the Act does not begin until June 2012 whereas the IPA has already procured SRECs for 2012 and beyond through the 20-year long-term contracts. ICEA recognizes the policy and operational arguments in favor of distributed generation renewable resources and is not opposed to holding workshops to discuss the potential benefits and possible plan for a future DG procurement. ICEA insists that the existing proposal, however, should be denied because it is unnecessary, devoid of sufficient detail, and carries the potential for unreasonable costs.

6. Solar Alliance's Position

The Solar Alliance urges the IPA to modify its procurement plan for SRECs by developing a long-term strategy that incorporates contracts of ten years, and that includes securitization by the IPA of the ACP and uses it as the financing mechanism. The Solar Alliance also recommends the IPA support development of distributed generation, a critical component to receiving the full benefits of solar on the grid.

The Solar Alliance asserts that engaging in long-term contracts, developing alternative financing mechanisms and supporting distributed generation will help to:

- Ensure there is adequate solar supply to meet the Legislative mandates;
- Provide an opportunity for multiple solar providers to participate in the market, thus ensuring a more competitive price and maximizing the use of available renewable funds;
- Encourage a sustainable, long-term solar industry;

- Create a more robust solar market with more efficient pricing than would have otherwise been the case; and
- Provide experience to the IPA, utilities and other market participants that will be valuable as the market unfolds in Illinois.

According to the Solar Alliance, the IPA's 2012 Plan provides an historical SREC price chart dating back to June 2010. The chart SREC prices declining drastically from approximately $250 to $300 per MWh in June 2010 to approximately $50 to $75 per MWh in late July 2011. The Solar Alliance is concerned that the average SREC prices shown are static and represent prices in markets with significant over-supply. The Solar Alliance believes these prices should not be used to determine a solar benchmark for Illinois because temporary forces are causing low SREC prices in these markets. The Solar alliance claims that a benchmark that relies on these prices would be unrealistically low. The Solar Alliance asserts that reported pricing per MWh for the District of Columbia, Ohio, and Delaware is approximately 400% to 500% below current trading pricing.

In the Solar Alliance's view, benchmarking for the solar procurement should reflect pricing data that is more representative of historical SREC price trends. The Solar Alliance asserts that while it would be tempting to buy SRECs on the spot market or one-year contracts to take advantage of the current oversupply, this creates a significant price risk when markets are no longer oversupplied.

The Solar Alliance claims these average prices are generally a mixture of long-term contracted SREC "strips" (at lower prices) and spot market trades (at significantly higher prices). The Solar Alliance says data sources for separate pricing of long-term strips is more limited. According to the Solar Alliance, nearly 100% of active projects in that market have received an additional subsidy of $1 per watt or more, and the market is significantly oversaturated, depressing REC prices below the levels that would be currently necessary for a project financed with standalone RECs.

The Solar Alliance says that while it understands the limitations placed on the IPA with its obligation to keep certain information confidential, the Solar Alliance feels all industries would benefit from more transparent price information. The Solar Alliance recommends that to the extent possible, the Commission direct the IPA to provide more information on the future price curve. The Solar Alliance claims the value of SRECs is driven by multiple factors including geographic market, power prices, irradiance, sales tax, and solar RPS targets. Alternatively, the Solar Alliance suggests that the Commission could direct the IPA to develop and publish a bid ceiling that is loosely based on actual bids, without violating confidentiality data.

The Solar Alliance applauds the IPA for including long-term RECs in the Plan and the decision to sort bids according to price and source. The Solar Alliance claims that solar project development is driven fundamentally by the amount of revenue required to support a project and the certainty or transparency of that revenue stream. The Solar Alliance says the availability of long-term contracts with reasonable terms and conditions is fundamental to a well-functioning SREC market, and the availability of financing depends on the investor confidence in long-term revenue streams. Investors greatly discount future revenue streams due to market and regulatory risk, only placing value on contracted SRECs.

The Solar Alliance also applauds the IPA for inclusion of a 25% distributed generation solar program in the Plan. The Solar Alliance believes a DG program will promote a well-balanced solar industry, while providing enhanced value for Illinois. The Solar Alliance claims the benefits of a DG program include: distribution and transmission savings, generation savings, line loss savings, capacity value, and fixed operations and maintenance savings.

The Solar Alliance praises the IPA for hosting a series of workshops between January and March 2012 to assist in the designing and announcement of the DG SREC procurement program by June 2012. The Solar Alliance, however, is concerned about the timing implication if the minimum 25% DG Solar procurement expectation is completed as planned for December 2012. The Solar Alliance says if the main procurements takes place in the spring and spends a portion of the RRB, leaving the DG Solar procurement to the end of the year, the budget is implicitly set for the DG procurement, and could affect the "at least 25% solar DG" expectation.

The Solar Alliance suggests that the DG market should not be expected to deliver volume with the same average clearing price as the 75% non-DG portion. Smaller systems (less than 50 kW) have a different cost structure than large systems. The Solar Alliance claims the market clearing price in an auction for SRECs associated with smaller systems can be approximately 30% higher than the market clearing price of larger systems. The Solar Alliance believes this price structure should be taken into account when determining the main procurement budget and demand for solar. To the extent this issue affects the main procurement, the Solar Alliance hopes for more clarity on how the two solar procurements will be designed. The Solar Alliance says it recognizes that the details of the DG Solar procurement will be worked out in workshop proceedings, and appreciates the opportunity to be involved in any solar working group meetings as a stakeholder on this and future concerns going forward.

The 2012 Plan also indicates that supply contracts secured through the spring 2011 procurement events will commence in June 2012, some contracts may be effective at a later date. The Solar Alliance says these procured volumes will be in addition to those electricity supplies already secured via legacy contract sources from the swap contracts resulting from the 2007 rate-settlement agreement, and the 2010 and 2011 IPA procurement cycles.

The Solar Alliance believes that while these timelines are eminently reasonable for the delivery of SRECs from an existing project, they effectively foreclose on the construction of a new project. The Solar Alliance asserts that even a relatively modest (0.5 MW) solar PV project takes several months to move from conception to completion. Accordingly, the Solar Alliance recommends that the Commission direct the IPA provide a minimum of six months, with nine to twelve months being ideal, between these two events to accommodate new construction projects.

The Solar Alliance recognizes and appreciates that the IPA reassesses the twenty-year RRB each year. The Solar Alliance recommends that the Commission direct the IPA to revisit the projected portfolio requirements annually. The Solar Alliance asserts that shopping rates can change, and extrapolating forward a trend for 20 years based on limited data can lead to an incorrect assessment of volume in out years. The Solar Alliance also recommends the use of utility expected load projections rather than utility low load projections when calculating the portfolio volumes for the first five years. Finally, the Solar Alliance recommends that the Commission direct the IPA to publish the projected shopping trend, and resulting projected MWh of required wind and solar, to ensure a transparent and competitive procurement process.

It is the Solar Alliance's opinion that one-year bids and twenty-year bids cannot be equitably compared, whether or not these bids are normalized through the use of a NPV. The Solar Alliance argues that while NPV is a valuable tool for comparing differently "shaped" contracts of equivalent terms, participants submitting bids of different length would need to use the same discount rate for evaluation by NPV. The Solar Alliance recommends the Commission direct the IPA to publish the discount rate it will use to evaluate bids prior to the submittal of bids.

In its Response to Objections, the Solar Alliance insists that the IPA has the legal authority to procure DG Solar under Section 1-75 of the IPA Act. That statute specifies that "[t]he Planning and Procurement Bureau has the . . . duties and responsibilities of (1) "develop[ing] procurement plans and . . . competitive procurement processes"; (2) "prepar[ing and conducting] a competitive procurement process [for power and energy resources] to ensure adequate, reliable, affordable, efficient, and environmentally sustainable electric service at the lowest cost over time, taking into account any benefits of price stability" (the "least-cost" provision); and (3) procuring "cost-effective renewable energy resources."

The Solar Alliance claims this statute sets out these three distinct responsibilities and duties in separate subsections of the Act. According to the Solar Alliance, the requirements included in each subsection were written by the Legislature to apply only to that respective subsection. The Solar Alliance says the U.S. Supreme Court, applying well-established canons of statutory construction, has long held that courts should not construe different terms within the same statute to embody the same meaning, that courts must, if possible, give effect to every clause and word of a statute, and that a statute should be interpreted so as not to render one part inoperative. The Solar Alliance says the IPA must read each requirement on its own. First, the IPA has a requirement to develop a procurement Plan and competitive procurement processes. Second, the IPA must prepare a competitive procurement process for power and energy to ensure electric service at "least cost." Third, the IPA must procure "cost-effective" renewable energy resources to fulfill the RPS.

The Solar Alliance says the Legislature defines "cost-effective" for purposes of the RPS to mean "the costs of procuring renewable energy resources do not cause the limit stated in [the price ceiling relative to previous electric rates] to be exceeded and do not exceed benchmarks based on market prices for renewable energy resources in the region."

The Solar Alliance notes that some intervenors assert that the IPA is also required to acquire those renewable energy resources "at least cost," and therefore assert that the separate DG Solar procurement would be illegal because it would not be the least-cost alternative. However, the Solar Alliance believes this is a misinterpretation of the statute.

The Solar Alliance says Section 16-111.5 of the PUA requires any "electric utility that on December 31, 2005 served at least 100,000 customers in Illinois [to] procure power and energy for its eligible retail customers in accordance with the applicable provisions set forth in [IPA Act and this Section]."

The Solar Alliance concludes that taken together, these two statutory sections require the utilities to purchase those resources mentioned in Section 16-111.5 of the PUA (power and energy resources) through the IPA procurement process at the least cost over time, taking into account price stability. The Solar Alliance claims it is important that renewable resources are not included in Section 16-111.5.

According to the Solar Alliance, applying the canons of statutory construction above, it must be assumed that the Illinois Legislature purposefully excluded renewable energy resources from these two statutory sections, and they are not subject to this "least cost" requirement. The Solar Alliance says the Legislature determined renewable energy resources should be purchased subject to a different test: whether the renewable energy resource was "cost-effective." The Solar Alliance states that while conventional energy and power resources must be purchased at least cost (taking price stability into account), the RECs and SRECs that must be purchased according to Section 1-75(c) of the IPA Act need not be.

The Solar Alliance says the IPA must consider only whether RECs and SRECs it purchases to fulfill the RPS obligation are cost-effective, which has been defined statutorily. The IPA claims this means the additional cost of the RECs and SRECs must not cause rates to exceed "(1) 2.015% of the amount paid per kilowatt hour by [eligible retail] customers during the year ending May 31, 2007 or (2) the incremental amount per kilowatt hour paid for those resources in 2011," nor to exceed benchmarks based on market prices for renewable energy resources in the region.

The Solar Alliance states that within the cost bounds discussed above, the IPA can and should consider additional value added by distributed generation resources that could not be provided through centralized, utility-scale projects when determining what types of renewable resources shall be procured to fulfill the RPS requirements. The Solar Alliance says these benefits are many and varied, and include: (1) distribution and transmission savings; (2) generation savings; (3) fixed operations and maintenance savings; (4) fuel and purchased power savings; (5) line loss savings; and (6) capacity value.

In its Reply to Responses, the Solar Alliance maintains that ComEd's arguments must fail because the IPA has the legal authority to include DG Solar in the procurement and to consider the benefits of DG Solar that cannot be provided through centralized, utility-scale projects. The Solar Alliance insists that beyond the cost cap and geographic limitations in Section1-75(c)(2)(E) of the IPA Act, the Illinois Legislature left the IPA to decide how the RPS should be procured. The Solar Alliance believes ComEd's conclusion that the DG Solar program is illegal is incorrect and ignores the IPA's authority to reasonably interpret the RPS requirements. The Solar Alliance says the IPA has provided a reasonable interpretation of the RPS requirements in deciding to include a separate DG Solar procurement, and this interpretation should be upheld.

The Solar Alliance contends that ComEd provides a similarly constrained interpretation of Illinois law by focusing solely on the costs of DG Solar. The Solar Alliance maintains that within the scope of cost and geographic limitations in Section 1-75(c)(2)(E) of the IPA Act, the IPA can and should consider additional value added by DG Solar that cannot be provided by centralized, utility-scale projects. The Solar Alliance says those benefits include: (1) distribution and transmission savings; (2) generation savings; (3) fixed operations and maintenance savings; (4) fuel and purchased power savings; (5) line loss savings; and (6) capacity value. The Solar Alliance believes the added value of DG Solar provides additional support for the IPA's DG Solar program, and the Commission should uphold that portion of the Plan.

7. AG's Position

The AG supports the provisions in the 2012 Plan to hold workshops on distributed solar resources. The AG believes the process for integrating distributed solar resources in the IPA procurement is in its infancy, and it is good policy to seek input from parties with expertise and resources in this area. The AG suggests that will enable the IPA and the parties participating in the development of solar power to learn from each other so that an adequate supply of solar renewable resources is available. In the AG's view, ComEd's suggestion that there are legal obstacles to proceeding as outlined in the 2012 Plan should be rejected as premature: workshops will inform the design for procurement of distributed solar resources, at which time the contours of the procurement will be clear and can be reviewed.

According to the AG, it is worth noting that distributed solar resources are produced and supplied very differently from other resources. The AG says small scale solar energy installations, on houses, small business, schools, and other relatively small buildings, produce power where a large portion of it is consumed, benefiting the overall system by reducing distribution costs and wear-and-tear. The AG also says other significant differences are the scale of capital needed to install a "roof-top" sized system and the administrative resources available for such small installations. The AG suggests it may be appropriate to tailor access to IPA procurement for systems of this size, for example, through aggregation or simplified contract processes. The AG believes a workshop process in advance of developing such accommodations can involve interested and knowledgeable people and open the procurement process to more voices. The AG supports the provisions of the 2012 Plan that provide for workshops on the use and incorporation of distributed solar resources in the IPA's Plan.

8. IPA's Position

The IPA states that after careful consideration of the comments and objections, the IPA recommends that the Commission remove the distributed SREC proposal from the current Plan. The IPA remains committed to the inclusion of distributed SRECs in future Plans, but finds that detailed workshops would be beneficial to the development of the issue, prior to the Commission's consideration of the Plan. The IPA recommends that all issues raised by the responding parties be considered in workshops to be held during January 2012 through May 2012. In these workshops the IPA will further evaluate, and take input on, whether a procurement plan should include a standard offer contract in a manner that is consistent with the IPA Act and the PUA.

In its Reply to Responses, the IPA states that since its Response to Objections, the Illinois legislature has enacted an amendment to the Illinois renewable resources portfolio standard in Section 1-75(c) of the IPA Act:

> Of the renewable energy resources procured pursuant to this Section, at least the following percentages shall come from distributed renewable energy generation devices: 0.5% by June 1, 2013, 0.75% by June 1, 2014, and 1% by June 1, 2015 and thereafter. To the extent available, half of the renewable energy resources procured from distributed renewable energy generation shall come from devices of less than 25 kilowatts in nameplate capacity.
>
> Renewable energy resources procured from distributed generation devices may also count towards the required percentages for wind and solar photovoltaics. Procurement of renewable energy resources from distributed renewable energy generation devices shall be done on an annual basis through multi-year contracts of no less than 5 years, and shall consist solely of renewable energy credits.
>
> The Agency shall create credit requirements for suppliers of distributed renewable energy. In order to minimize the administrative burden on contracting entities, the Agency shall solicit the use of third-party organizations to aggregate distributed renewable energy into groups of no less than one megawatt in installed capacity. These third-party organizations shall administer contracts with individual distributed renewable energy generation device owners. An individual distributed renewable energy generation device owner shall have the ability to

> measure the output of his or her distributed renewable energy generation device. (SB 1652 Enrolled, passed October 26, 2011)

Given the legislative direction to procure 0.5% of the RPS from distributed renewable energy generation devices by June 1, 2013, and given the specific direction that one-half of the distributed generation is required to come from devices of less than 25 kilowatts, the IPA recommends that the Commission defer consideration of a distributed solar generation procurement event until a more specific proposal is submitted by the IPA in the 2013 Procurement Plan that is consistent with the IPA Act. The IPA reiterates its commitment to hold workshops to thoroughly develop a distributed solar generation procurement.

9. ELPC's Position

In its Response to Objections, ELPC says the IPA Act requires the IPA to procure “cost-effective renewable energy resources” according to a statutorily-mandated schedule and includes a specific “carve-out” for solar energy resources. ELPC says the Solar Carve Out requires that in 2012, 0.5% of renewable resources procured for RPS compliance must come from solar PV. ELPC says the requirement increases to 1.5% in 2013, 3% in 2014, 6% in 2015 and each year thereafter. ELPC estimates that in Plan Year 2016, the IPA, on behalf of the utilities, will be required to procure SRECs equivalent to the annual output from approximately 211 MW of solar. ELPC notes the IPA signed two long-term PPAs in 2010 that will satisfy approximately 11% of this requirement.

ELPC says until now, the IPA’s renewable energy procurement strategy has focused exclusively on RECs generated by large utility-scale renewable energy projects developed by companies such as Exelon Energy, one of the largest electric generating companies in the country, NextEra (operating revenues of more than $15 billion and generating capacity of 42,500 MW), Invenergy, the largest independent wind developer in the country, and Iberdrola Renewables, a Spanish company that has successfully developed 40 utility-scale renewable energy projects across the United States. ELPC asserts that these companies have the professional energy traders, attorneys, credit reserves and cash balances necessary to successfully compete in the IPA’s highly complex auction process. ELPC asserts that smaller-scale producers such as Illinois homeowners, small business owners, school districts, housing authorities, retail chain stores and other small energy companies, do not have the resources to meaningfully participate in the IPA’s auction-based procurement process. ELPC believes bidding requirements are too complex and transaction costs are too high to justify participation for small projects. ELPC states that although the IPA did not set an explicit minimum-size threshold for the procurements, the bidding and negotiation process effectively excluded smaller potential suppliers. ELPC believes a few revisions to the process would include smaller potential suppliers of SRECs and thereby increase the cost effectiveness of the procurement.

ELPC claims that without a separate procurement program for distributed solar resources, it is very likely that the Illinois Solar Carve Out will be met entirely with SRECs from large, utility-scale developments. ELPC asserts this would result in a highly imbalanced procurement strategy that could lead to higher costs for Illinois ratepayers in the long run. ELPC says in 2010 alone, the U.S. solar industry installed 890 MW of grid connected PV. ELPC asserts that more than two-thirds of these capacity additions, or 609 MW, were distributed systems installed on residential, commercial and industrial sites. ELPC thinks a balanced procurement strategy that supports both utility-scale and distributed solar development is necessary to spur competition and lower costs across the industry.

ELPC believes the IPA's proposal to procure at least 25% of its solar renewable energy procurement obligation from distributed resources will help the IPA prudently balance its renewable energy portfolio and fulfill its statutory duty to develop electricity procurement plans that will "ensure adequate, reliable, affordable, efficient, and environmentally sustainable electric service at the lowest total cost over time."

ELPC recommends that, at a minimum, the Commission approve the IPA's planned workshop process to design a distributed solar procurement program for inclusion in the 2013 Plan. Additionally, ELPC supports Staff's suggestion for a "relatively modest pilot program" which could be introduced in 2012. ELPC suggests a pilot program of perhaps 1-2 MW of solar in 2012 would enable the IPA, the expanded universe of solar suppliers and the utilities to gain experience and prepare for full program implementation in 2013 with only a minimal, if any, impact on the IPA's overall budget.

ELPC further recommends that the Commission include, as part of the scope of any IPA workshop process, an assessment of the various grid and cost benefits of distributed generation in Illinois. ELPC says other state utility commissions have developed methodologies to estimate the benefits of distributed generation. ELPC thinks this kind of assessment, which could be informed by the various efforts in other state commissions, would be extremely useful in the IPA's development and the Commission's review of future renewable energy procurement plans.

ELPC believes ComEd's legal objections are premature. ELPC says the IPA has not proposed a final distributed solar program, it has announced a series of workshops to design a program in the future. ELPC says ComEd can participate in the workshops and the Commission can review the final program to ensure that it is consistent with all statutory requirements. ELPC asserts there is no basis for the Commission to issue an advisory opinion about the legality of a distributed solar procurement program before the program is even fully specified.

ELPC also claims that ComEd's argument that the IPA's proposal creates an illegal "preference" for small solar resources fails to consider that the existing IPA procurement strategy, which functionally excludes distributed solar projects, is essentially a "preference" for utility-scale projects. ELPC asserts that the IPA's distributed solar proposal is an effort to increase the cost-effectiveness of the procurement by correcting this problem and expanding the resources currently able to participate in the procurement process. According to ELPC, ComEd provides no support for its argument that a distributed solar program will raise costs to consumers by limiting participation in the bidding process. ELPC suggests that an imbalanced portfolio that relies exclusively on utility-scale resources will fail to capture the various benefits of distributed generation and could lead to higher costs for Illinois ratepayers, in this procurement as well as over the long term.

ELPC agrees that the Commission should have the opportunity to approve the details of a distributed solar program before it is opened up for broad participation. ELPC claims this could be accomplished with minor edits to the Plan. ELPC suggests the Commission could clarify the timeline to (1) conduct workshops as proposed in January-May 2012, (2) roll-out a modest pilot program in late 2012, and (3) include full program details for Commission approval as part of the IPA's 2013 Plan. ELPC also suggests the Commission could clarify that the IPA will consider "at least" the two identified program options without excluding consideration of other appropriate options.

ELPC and Vote Solar (jointly, "ELPC/VS") jointly filed a Reply to Responses. ELPC/VS support the IPA's proposal for a workshop process and believe the Commission should ensure that the workshops will result in a detailed distributed solar program proposal which can be included in the IPA's 2013 procurement plan. According to ELPC/VS, the Commission should also provide the IPA with the flexibility necessary to meet the requirements of Illinois' new distributed generation "carve-out" legislation, which will require 0.5% of the renewable energy resources procured by the IPA to come from "distributed renewable energy generation devices" by June 1, 2013.

ELPC/VS continue to believe it would be prudent to begin procuring distributed solar resources as soon as possible, and note that no party objected to a workshop process. ELPC/VS suggest at the very least the Commission should approve the IPA's proposal to conduct "detailed workshops" to evaluate and design a distributed solar program for inclusion in future plans.

According to ELPC/VS, the IPA's Final Plan included a number of topics for discussion in the workshop process, including:

- Definitions for "small" and "mid-size" distributed solar systems eligible to participate in the procurement;
- The terms and conditions under which distributed SREC providers would verify SREC deliveries;
- Administrative procedures that minimize transaction costs for participants and administrative burdens for the utilities and the IPA;

- A process for assessing program results, including the energy and capacity values of the distributed solar energy developed as a result of the program, and the benefits to the Illinois distribution grid;

- A process for modifying the program over time;

- Credit and security requirements for SREC suppliers;

- Whether eligibility will be limited to distributed solar PV facilities (a) within the buying utility's service territory, (b) within Illinois, (c) within either Illinois or a state that adjoins Illinois, or (d) elsewhere;

- The portion of the REC spending limit that would be dedicated to acquiring SRECs from distributed solar resources.

ELPC/VS state that without foreclosing the ability of the IPA to add other topics, the Commission should approve these suggested workshop topics in order to ensure that the workshop process is focused and will result in a distributed solar procurement program with the necessary details to support the Commission's review and approval in the 2013 procurement process.

ELPC/VS suggest the Commission should not address ComEd's legal objections to a future distributed solar program before the details of the program are developed and proposed. ELPC/VS say the Commission will have the opportunity to fully address legal objections raised by ComEd or any other party in next year's procurement case after the details of the program are developed through workshops. To the extent that ComEd argues that any "preference" for distributed resources is illegal under Illinois law, ELPC/VS claim that objection has been effectively mooted by the Illinois legislature's enactment of a new distributed generation "carve-out."

ELPC/VS state that on October 26, 2011, the Illinois legislature enacted an amendment to the Illinois renewable resources portfolio standard to create a new distributed generation "carve-out":

> Of the renewable energy resources procured pursuant to this Section, at least the following percentages shall come from distributed renewable energy generation devices: 0.5% by June 1, 2013, 0.75% by June 1, 2014, and 1% by June 1, 2015 and thereafter. To the extent available, half of the renewable energy resources procured from distributed renewable energy generation shall come from devices of less than 25 kilowatts in nameplate capacity. (SB 1652 Enrolled, passed October 26, 2011 (amending Section 1-75(c) of the IPA Act))

According to ELPC/VS, this statute will require the IPA to procure nearly 17,000 RECs from distributed generation resources by June 1, 2013. They say if procured entirely from solar, this would amount to nearly 13 MW of solar nameplate capacity, half of which would need to come from systems of less than 25 kW.

ELPC/VS believe it is too early to predict how the IPA will need to prepare to comply with the distributed generation carve out. ELPC/VS suggest the Commission should provide the IPA with sufficient flexibility to administer its 2012 procurement in a way that helps it prepare for this new compliance obligation. ELPC/VS say this could include, for example, the ability to administer a pilot program in 2012 for the procurement of distributed SRECs, if the IPA determines that is necessary to prepare for a full-scale program in 2013.

In their Reply to Responses, ELPC/VS provide language that they recommend be included in the Final IPA Plan.

10. ISEA's Position

ISEA states that the RPS statutory requirement of 1.5% of electricity generated from solar sources by 2025 equates to an estimated capacity requirement of 600-700 nameplate megawatts, depending on geographic location of the installations and technology efficiency. ISEA estimates that distributive solar energy installations can produce 10 watts per square foot, 435 kW per acre and 278 MW per square mile. ISEA asserts that only a few square miles of surface area would be required to achieve the RPS goal. ISEA suggests that surface area requirements for solar can be satisfied by using roof tops, parking lots, right of ways, brownfields and other marginal sites. ISEA says such installation sites are widely available in Illinois. ISEA believes the IPA's proposal to purchase solar energy to achieve the 1.5% RPS goal for solar energy procurement is adequate.

ISEA claims solar power is an inherently reliable source of electricity when managed properly. ISEA notes solar electricity is a daytime power source. ISEA says predicting availability of sunlight for power needs can be done on a very reliable basis. ISEA states that while annual insolation in Illinois is approximately 50% of total potential year round, and over 60% in the summer time, run times for solar facilities, when there is some amount of sunlight available, is over 60% year round and approaches 90% in the summertime. ISEA claims computer modeling on a micro-climate basis can fine tune sunlight predictions, and energy storage and dispatching systems can balance demand with solar energy supply. ISEA thinks distributed solar energy is reliable within the meaning of the applicable statute.

ISEA also states that economic power storage and dispatching technologies to smooth out solar generation can be readily developed by scaling up of demonstration projects, especially megawatt scale sodium sulfide electrolyte systems.

ISEA says that contrary to objections filed in this proceeding, solar electricity is not an inherently expensive product that cannot compete with traditional fossil fuel and nuclear power generation. ISEA claims this assertion is faulty on two fronts. First, ISEA says there has been a significant decline in the cost and price of solar energy since 2009, beginning with lower feedstock prices, then lower module prices, lower inverter prices and finally lower installed system prices. Installed system prices have declined in large markets like Germany and California by 10 percent or more per year since 2009, and about 7% a year in small markets like Illinois. ISEA thinks that as production scales up, costs will continue to drop.

Second, ISEA says no new fossil or nuclear power plant construction has been undertaken in Illinois for the past decade, so the costs of such plants cannot be compared to new solar power plant production. ISEA claims solar has been under the onus of "grid parity" comparison. According to ISEA, this means that a PV system installed in 2011 has to equal the retail cost of electricity of the grid, which is largely supplied by 40-50 year old power plants. ISEA claims this is like comparing the price of a 2011 car to one built in 1971, which is economically unsound, even accounting for inflation factor. ISEA asserts that what needs to be incorporated in proper comparison is "new power plant construction" parity: what 100 MW of solar would cost over a 20 to 30-year period compared to 100 MW of new coal or nuclear power plant capacity built today.

ISEA claims the forgoing comparison would show that solar power is affordable when compared to the expected higher construction, operation and decommissioning costs of fossil fuel and nuclear plants. ISEA believes solar is affordable within the meaning of the statute.

ISEA says solar power is criticized because it has a lower capacity factor than traditional baseload power plants. ISEA maintains that solar's capacity factor can be improved by tracking systems and compensated for deployment of dispatching and storage technologies. ISEA believes it is likely that improvements in efficiency and demand to the grid and end users, the so-called "smart" technologies, will enable a closer linkage of using relatively intermittent solar power with more flexible and efficient demand.

The initial ISEA position would be in support of ELPC with expansion on the impact of the solar/distributive power market. The ISEA agrees on the timing aspect that at the cost of losing an additional year, it is better to get an equitable program out in late 2012 or even 2013 rather than something sooner that is inadequate.

ISEA claims that solar is an inherently environmentally sustainable technology. ISEA says there are no end use emissions in the generation of solar power, and water usage, an increasing concern even in the Great Lakes Region, is minimal at best, limited to module cleaning and related maintenance. ISEA says nearly all of the components of solar power have or can be reused or recycled, and any hazardous substances are encapsulated or hermetically sealed, minimizing that impact. Installations are relatively non-invasive, especially if the mounting systems are non-penetrating ballasts. ISEA claims low profiles minimize aesthetic concerns. ISEA also says the construction period for installations are usually in weeks for kW scale systems or months for MW-scale installations, which make them less disruptive to surrounding communities.

ISEA argues that because the operation of solar does not require fuel contracts that may be disrupted due to extreme weather, military conflict or other types of “force majeure” conditions, there is an inherent stability of operation costs. ISEA suggests as many solar technologies and systems have been in commercial existence for decades, accurate electricity output can reasonably predicted and, allowing for some variation in climate and a modest degradation factor over the life of a system, price stability can be largely assured, especially if backed up by insurance and warranty factors. ISEA says the concern over whether too high a price would be factored in by long-term contracts can be minimized by several factors. First, ISEA asserts installed costs are declining, abetted by declining offerings in feed-in-tariffs ("FIT"), PPAs and SRECs. ISEA asserts that establishing a steady, long-term and bankable market for SRECs or any other financial instrument will encourage significant competition and continued competitive pricing. According to ISEA, declining factors will be in itself a form of stability, if done in a non-precipitous fashion.

ISEA respectfully requests its comments be included in the proposed 2012 workshops to enable an effective and cost-effective procurement for solar that can take advantages of the increasing benefits of this power source.

11. Vote Solar's Position

Vote Solar says it supports the recommendations of Staff and other parties to develop a dedicated program for solar distributed generation. Vote Solar alleges that solar programs have several benefits. Vote Solar claims these programs efficiently leverage private capital, allowing individuals and businesses to invest in their own solar generators. Vote Soar also asserts that solar is delivered inside of distribution networks, making the grid more robust. Vote Solar also says developing a program where residential, commercial, and small wholesale providers can participate, in addition to larger wholesale providers, results in a stronger, more robust solar economy.

According to Vote Solar, Staff and other parties have recommended that the IPA hold workshops to design and implement a program to enable the legislatively-mandated solar carve-out. Vote Solar supports this recommendation. Vote Solar suggests that in ways that can benefit many different stakeholders, solar is different than other technologies. Vote Solar says that to harness those benefits, special care must be taken to examine different siting opportunities and ownership models, review the results of de facto state laboratories that have piloted different models, understand the keys that drive solar markets, and identify best practices that will enable the best outcome for Illinois ratepayers.

Vote Solar claims solar is different than some other technologies in that it lends itself to many different siting opportunities and ownership models. Vote Solar alleges solar can participate in retail markets, in which energy consumers install solar behind the meter, and the value of the generation comes from reduced utility purchases. For the consumer, the benefit comes from reducing utility bills and providing a hedge against future rate increases. Vote Solar says for utilities, the benefit of this model is that it leverages private capital to provide high-value generation inside of distribution networks, thereby increasing the robustness of the grid. For policymakers, Vote Solar claims some benefits of this model are that it leverages individual investment, and because incentives are used to cover the margin between retail, rather than wholesale rates, makes efficient use of ratepayer dollars.

Vote Solar says solar can also participate in wholesale markets, in which generation is sold to utilities for further distribution and sale to utility customers. Vote Solar states that wholesale distributed generation has seen tremendous growth both internationally and in the US. Vote Solar claims these programs are delivering solar projects under the cost of building new combined cycle natural gas turbines. Vote Solar says the benefits to the utilities and policymakers are diversity in generating resources as well as a scalable industry capable of rapidly installing zero-emission generating resources.

Vote Solar asserts that enabling this diversity of business opportunities, with different benefits to different stakeholders, requires special care in establishing enabling market policies. Vote Solar believes that the ratepayers and solar businesses of Illinois will benefit from deliberate consideration of ways to maximize the diversity of benefits that solar can provide.

According to Vote Solar, solar PV have experienced extraordinary cost reductions in the past three years, with the result that solar module costs are no longer the largest part of the overall cost of an installation. Vote Solar says addressing soft costs, including business overhead, is one of the most fruitful ways that program design can deliver the lowest costs to ratepayers. Vote Solar suggests addressing the needs of solar businesses is the most effective and expedient approach for developing efficient, low-friction markets that deliver the lowest installed costs.

Vote Solar alleges that over the past several years, various states across the country have experimented with different models for enabling solar markets. Vote Solar avers that some programs rely on up-front rebates for self-generation, while others have used competitive programs for SRECs, i.e., standard contracts for SRECs that decline in response to market conditions; programs that utilize long-term contracts in order to remove risks, and therefore costs; programs that are committed to floating SREC contract terms; bundled SREC and energy competitive auctions; bundled SREC and energy standard contracts; and combinations thereof targeted to different market niches. Vote Solar claims the result of these efforts is an extraordinary amount of data about the effects of program design. Illinois ratepayers can benefit from a deliberate examination of these experiences in order to tap into best practices for delivering maximum value.

Vote Solar supports the recommendations that urge the Commission to order the IPA to hold workshops in January through May of 2012 to design a distributed solar procurement program for roll-out on a pilot basis in late 2012, and full roll-out in 2013.

Vote Solar believes the workshops should include:

- Discussion of topics included at pages 22-23 of Staff's brief;
- Publication of a study identifying/quantifying the benefits of distributed solar to the Illinois electric grid;
- Development of a pilot distributed solar program for roll-out in late 2012; and
- Development of a full distributed solar program for inclusion in the IPA's 2013 procurement plan (released in August 2012).

12. IREC's Position

IREC believes that the procurement planning process is an appropriate forum to consider the benefits of distributed solar energy facilities. IREC strongly supports the IPA's proposal to include a distributed SREC procurement program. IREC claims that inclusion of DG Solar into procurement planning creates the opportunity for planners to recognize the value of DG in offsetting the need for peak generation capacity and to utilize that value to defer transmission and distribution capacity additions. IREC believes that ignoring the benefits of DG Solar can result in unnecessary redundancy in generation capacity, as the high coincidence factor of solar with peak demand can substitute as peaking resources for natural gas-fueled plants, which are the marginal producers during the summer months in both PJM and MISO. IREC asserts it is vital in the procurement planning process to consider the value and benefits of DG and to structure appropriate mechanisms to encourage its growth.

IREC claims DG Solar brings important benefits to the grid, including shaving peak demand, reducing line losses, and providing the potential for utilities to defer transmission and distribution upgrades. IREC says even parties with objections to immediate implementation of the distributed SREC program acknowledge the grid benefits of DG Solar. IREC adds that these parties insist that DG Solar's benefits warrant further investigation and indicate a willingness to participate in future workshops to determine the extent of such benefits. IREC states that procurement planning is an appropriate place to encourage the further development of DG Solar because it can reduce the need to add new generation capacity and bring various other operational benefits that are relevant to the procurement planning process.

IREC claims other state utility commissions are developing methodologies to capture the operational and grid benefits of DG Solar.

IREC suggests that with the growing body of data supporting the value of DG Solar, and the inherent importance of those benefits to system planning, IREC supports IPA's inclusion of a plan to encourage DG Solar while satisfying procurement requirements. This effectively advances two of the State's objectives—procurement of solar and advancement of distributed, behind-the-meter generation resources—through one policy. IREC also suggests that implementing a separate procurement mechanism for distributed SRECs provides an opportunity to consider the benefits of DG Solar and to develop an appropriate mechanism to compensate DG Solar owners for the value they provide.

Overall, IREC applauds the inclusion of DG Solar in the procurement planning process. IREC supports the separate procurement process, including the use of standard offer contracts for distributed SREC sellers, as the appropriate framework to support greater development of DG Solar in Illinois.

The IPA Plan for distributed SREC procurement, as proposed, relies on further development of program details before it can be implemented and the Plan proposes a series of workshops between January and May 2012 to do that. The Plan proposes to announce the distributed SREC procurement plan by June 2012. Several parties, including AIC, Exelon and ICEA, support the idea of further investigation of the procurement of DG Solar, even as they object to the instant proposal for a separate procurement of distributed SRECs. IREC believes that these objections show a willingness to objectively explore the development of a DG Solar procurement mechanism. IREC is encouraged by AIC's and ComEd's willingness to actively participate in future workshops to explore the merits of DG Solar proposals.

IREC believes that the workshops should focus on accomplishing three major milestones:

- Design and commence a study to investigate the grid benefit of DG Solar and propose methods of compensating generators for that value;
- Plan and consider program design options for procuring distributed SRECs for a 2012 "pilot" program and make recommendations for implementing distributed SREC procurement as part of the 2013 procurement Plan; and
- File a publicly available report with the ICC that summarizes workshop activities, explains the results of the DG Solar grid benefits study, and makes recommendations for IPA distributed SREC procurement design and any other appropriate action to implement the recommendations in the report.

IREC notes that some parties claim that a separate "carve-out" for SRECs associated with small DG Solar is illegal are premature because the details of the program are not yet known. ComEd, in particular, takes issue with the possibility that distributed SRECs should receive a preference in the procurement process because the legislature has not authorized such a preference. IREC states that without program details of how distributed SRECs will be compensated or procured, there is no assurance that distributed SRECs will receive a preference, even if they participate in a separate auction. According to IREC, there is nothing definite in the Plan's distributed

SREC proposal to warrant substantive, legal objections. IREC expects that ComEd's concerns will be addressed through the workshop process, resulting in a process that complies with the law and recognizes the benefits of DG Solar to its grid.

IREC also believes objections that SREC procurement from small DG Solar will result in higher costs to ratepayers are premature pending the development of the program and likely ignore the benefits of DG. IREC says that assuming that distributed SRECs will result in higher costs than generic SREC procurement ignores the possibility that customers will be held indifferent if any additional compensation to distributed generators is limited to the benefits those generators provide to the grid. IREC states that to the extent that DG Solar is compensated only for costs that it allows utilities to avoid, such as deferring transmission and distribution upgrades or avoiding line losses, ratepayers will not bear any additional costs as a result of a procurement emphasis on DG Solar. IREC claims ratepayers will benefit from the long-term benefits of DG, including the fact that renewable sources of energy are a hedge against volatile fuel adjustment costs. IREC contends that without compensation for these many benefits, DG Solar owners essentially provide a benefit to the grid without compensation. IREC suggests that parties may satisfy their concerns about ratepayer impacts by participating in the workshops and supporting an accurate assessment of DG Solar's benefits to the grid.

IREC believes that deferment of the distributed SREC program to the 2013 Plan is reasonable, but suggests that proceeding with the 2012 distributed SREC program on a "pilot" basis is practical and will have *de minimus* ratepayer impacts. IREC claims it is important to note that the initial scope of the entire SREC program is limited to just 0.5% of the total RPS requirement for 2012. IREC says this ramps up to 1.5% in 2013. IREC asserts that the distributed SRECs for 2012 would represent merely 3 MW of capacity in 2012 and increase to 10 MW in 2013. IREC claims any negative impact of procuring the equivalent of 3 MW of distributed solar resources in 2012 is mitigated by the experience gained in administering the program and developing cost-effective mechanisms to encourage distributed solar growth prospectively. IREC also claims that if the program was implemented on an interim basis for 2012, to allow for full implementation in the 2013 Plan, the ratepayer impacts of procuring 3 MW of DG Solar will be minimal, even without accounting for the benefits of DG Solar. IREC says that accounting for the benefits of DG Solar is centrally important to moving forward with Illinois' ambitions to procure adequate solar resources to meet RPS obligations. IREC respectfully request that the Commission approve the Plan and require workshops to quantify DG Solar's benefits and develop a mechanism to compensate DG Solar owners.

13. City's Position

The City filed a Reply to Responses in which it addressed distributed SRECs. The City supports IPA's recommendation to conduct workshops in January through May, 2012 to develop the details of a plan to procure distributed SRECs. The City believes that the workshops should be designed to accomplish two primary objectives.

First, the City believes the workshops should develop the details of a DGSolar program that shall be included in the IPA's draft 2013 procurement Plan. Second, the City believes the workshops should produce a written report identifying and quantifying the benefits of DG Solar in Illinois. Besides these two discrete outcomes, the City recommends that the Commission's Order in this case provide the IPA with the flexibility to administer a pilot distributed generation procurement in 2012 if it determines that such a pilot would help prepare the state for the full roll-out of the program in 2013.

14. Constellation's Position

In its Reply to Responses, Constellation states that it continues to believe it is appropriate for the IPA to hold separate procurements for SRECs from DG Solar energy systems. Constellation asserts that distributed generation sources, including solar, provide many benefits. Constellation claims these benefits include the reduced need for new transmission, reduced line losses as distributed energy is generated and consumed on-site, reduced distribution upgrades through the extension of useful lives of lines and transformers, reduced need to upgrade transformers to support load growth, and enhanced distribution system performance through electricity counter-flow and reduced low-end volt gyrations. According to Constellation, DG Solar also helps protect appliances by providing improved power quality that defends against surges and sags. Constellation claims DG Solar is less vulnerable to security threats and rolling blackouts, and it has a significantly lower environmental footprint than other forms of renewable generation that require additional land use. Constellation believes a competitive DG Solar market in Illinois will spur significant competition, as the barriers to entry for developing small systems are far lower than for large scale generation. Constellation asserts that this competition will bring downward pressure to costs for the solar industry throughout Illinois, and benefit ratepayers accordingly. Constellation says to date, however, the IPA's auctions have successfully driven investment only in utility-scale renewable energy generation. Although Constellation supports the concept of workshops to finalize the details of a DG Solar procurement, Constellation believes it is appropriate to send the market signal as soon as possible that Illinois is committed to distributed generation.

15. Commission Conclusion

The IPA originally proposed to include in the 2012 Plan, the procurement of no less than 25% of the solar renewable energy procurement obligation from small and mid-sized distributed systems in Illinois. Subsequently, the IPA withdrew this proposal. As with long-term renewables, this proposal received significant comment with most of the support, not surprisingly, coming from parties in the solar industry.

The opponents of this proposal raised numerous concerns, questioning the legality of the proposal, complaining that it is overly vague, and questioning the validity of the proposed aggregator-only provision of the proposal. The IPA, in its Reply to Responses also notes that on October 26, 2011, the Illinois General Assembly passed SB 1652 which modifies the Illinois renewable resources standard in Section 1-75(c) of the IPA Act. Given this recent change in law, combined with the numerous concerns raised by the parties in this proceeding, the Commission finds that the distributed solar solicitation originally proposed by the IPA should not be included in the 2012 Plan.

The Commission believes it is best to defer consideration of a DG Solar procurement event until a more specific proposal is submitted by the IPA in the 2013 procurement Plan that is consistent with the IPA Act. The Commission, however, accepts the IPA's commitment to hold workshops to thoroughly develop a DG Solar procurement and hereby directs it to do so.

D. Identification of Renewable Energy Resources

1. ComEd's Position

According to ComEd, potential providers of renewable resources can more readily participate in the procurement process if they know with certainty whether they are eligible to participate in renewable procurements. Likewise, ComEd suggests utilities' costs and risks are also reduced if they can readily and definitively determine if particular generation associated with RECs qualifies as a "renewable energy resource[]" under Section 1-10 of the IPA Act. ComEd says the value of this certainty is recognized in connection with the obligation of ARES to acquire renewable resources, as set out in Section 16-115D of the PUA, where the IPA prepares a list of qualifying generation sources that appear on the Commission's web site.

ComEd states that determinations of whether a resource is renewable in the case of utility procurements appear to be made individually, at varying times during the process, and in a variety of ways, including in response to FAQ submissions and in response to direct inquiries to the IPA. ComEd believes that the compiling and publishing of a single, definitive list of eligible renewable resources applicable to utility procurements conducted under each approved Plan would reduce uncertainty for potential bidders and purchasers and reduce risk and, thus, ultimately costs. ComEd says that while compiling such a list is not a legal requirement applicable to utility procurement, as it is with respect to ARES' procurement, it is a procedure that can be adopted and included in a Commission-approved procurement Plan.

ComEd suggests that the Plan be amended to provide that the IPA, Staff, the Procurement Administrator, and the Procurement Monitor will jointly compile a list of generation sources qualifying as renewable resources under Section 1-10 of the IPA Act. Because the same definition of renewable resources governs the list already produced for ARES' procurement, ComEd believes any burden will be minimal. To maximize its utility, ComEd suggests that the list also indicate whether a particular source qualifies for any special type of procurement (e.g., wind resource).

ComEd further suggests that a list of renewable resources should be made available to potential bidders and utilities at least 14 days prior to the commencement of the first procurement event of that planning year. According to ComEd, bidders would certify in their bid application and in the supply agreement that the renewable resources they provide pursuant to that plan year agreement will be generated from a facility on that list. ComEd believes that list should remain in effect for that planning year. ComEd proposes that an updated list would then be generated for the next planning year, prior to that year's first renewable procurement.

In order to provide certainty, ComEd believes the Plan should provide that both potential bidders and purchasers can conclusively rely on this list of qualifying renewable resources in fulfilling their obligations under the Plan. ComEd suggests that because a comprehensive list must already be compiled for ARES procurement purposes, using the same standard, any incremental cost should be *de minimus*.

In its Reply to Responses ComEd indicates that it appreciates the concerns of Staff and IPA and, after careful consideration, believes its proposal can easily be amended to fully address each of those concerns, while still providing participants with the vast majority of the benefits of market certainty. Therefore, ComEd suggests that, rather than establishing a separate process or list, the Plan simply make clear that all parties and participants can rely on the most recent list of qualifying renewable resource generators prepared by the IPA for use in the parallel ARES process, i.e., the current IPA list as of the date the RECs are delivered, for generators existing as of the date of that list. ComEd claims that because no additional processes or updates would be required, this modification addresses both the IPA's concern about additional updates and Staff's concern about additional work being imposed on parties. ComEd also says that because the list would only be definitive as to generators in operation on the date when the list is issued, Staff's concern about generators "on the drawing board" or in the process of construction is eliminated.

According to ComEd the only remaining objection is Staff's assertion that there are differences between qualifying renewable resources for ARES and utilities that would impede use of this list in the utility context. ComEd believes Staff concern is overstated and appears to be based, in part, on a misreading of Section 16-115D of the PUA and, in part, on a misunderstanding of data used to prepare that list. ComEd states that with respect to the definition of renewable resource, Section 16-115D(a)(1) explicitly adopts for ARES the identical definition of renewable energy resources applicable to utilities, stating simply: "The definition of renewable energy resources contained in Section 1-10 of the Illinois Power Agency Act [i.e., the utilities' definition] applies to all renewable energy resources required to be procured by alternative retail electric suppliers." ComEd says it is true that ARES operating under Section 16-115D are not subject to the locational preferences specified in Section 1-75(c)(3) of the IPA Act, but ComEd claims that means that the list already prepared for ARES must include all renewable generators, without regard to the locational preference. Since this list itself contains the "location of generation," ComEd insists it is no obstacle to use it for utilities, too. Utilities and participants will simply have to check that the resource is both listed as qualifying and listed as being in a permissible location.

ComEd claims that Staff appears to misread the PUA itself in asserting that "Section 16-115D sets forth the additional requirement [for ARES] that the resource must be located within Illinois and/or the PJM and MISO footprints." According to ComEd, Section 16-115D, however, contains no such requirement. It appears to ComEd that the genesis of this concern is Section 16-115D's requirements that "renewable energy resources shall be independently verified through the PJM Environmental Information System Generation Attribute Tracking System (PJM-GATS) or the Midwest Renewable Energy Tracking System (M-RETS)," and that the IPA provide to PJM-GATS, M-RETS and ARES "information necessary to identify resources located in Illinois, within states that adjoin Illinois or within portions of the PJM and MISO footprint in the United States that qualify under the definition of renewable energy resources in Section 1-10 of the [IPA] Act for compliance with this Section 16-115D." ComEd contends that these provisions do not limit the location of renewable energy resources that can be used to satisfy ARES' renewable resource obligations; they limit the scope of the IPA's obligation to pre-identify qualifying resources to those in these locations. ComEd asserts that the statutory language does not prohibit use of resources from other locations, nor can such a requirement be inferred from the requirement that such resources be verified through PJM-GATS and M-RETS. ComEd suggests that Staff's concern also stems from a belief that PJM-GATS and M-RETS systems only include generators in the local area and, therefore, that an ARES list based on those systems may be incomplete. ComEd claims that both PJM-GATS and M-RETS do provide for the reporting of renewable energy resources from outside, as well as inside, their respective RTO footprints.

In ComEd's view, the concern over the potential omission of distant generation is also academic, and were it ever to actually materialize, is easily remedied. ComEd asserts that due to the locational preferences contained in the IPA Act, no supplier has ever won an RFP to supply a renewable resource from a facility located outside of Illinois or an adjoining state. Should a supplier ever win the right to provide such a resource and should the facility that the supplier intends to use to generate that resource not already be reflected on the IPA's list, ComEd suggests this issue created by such a scenario should not be difficult to remedy. According to ComEd, the supplier can simply contact the IPA and request to be added to the list. ComEd says a provision can be added to the supply agreement whereby the supplier agrees to supply renewable resources only from facilities identified on the list at the time delivery is made. ComEd believes this should provide the supplier the incentive to be sure its facility is on the IPA's list. ComEd also suggests this proposal takes the burden off of the IPA and places it on the supplier to identify facilities located outside of the PJM or MISO footprint that qualify as renewable energy resources under the IPA Act.

According to ComEd, the benefits of using the IPA's list should not be lost because of concern over such a very unlikely and easily remedied worry. ComEd maintains that the ARES list is a valid, pre-existing, and potentially very useful means of determining whether a generator qualifies as a renewable energy resource. ComEd says the vast majority of qualifying resources will be the same for both utilities and

ARES. In ComEd's view, any additional resources can be easily added to the list at the request of the supplier.

ComEd contends that WoW, in contrast, objects based largely on the remarkable – and plainly false – assertion that “[u]nlike [for] ARES, there is no restriction on the resources that could qualify for use as a renewable energy resource for utilities.” ComEd states that Section 1-10 of the IPA Act defines the “Renewable energy resources” that can meet utilities’ purchase obligations. ComEd says utilities are restricted to meeting their portfolio requirements through purchases from qualifying resources. ComEd also says that Section 16-115D(a)(1) expressly incorporates the exact same definition into the ARES’ purchase obligations. ComEd believes WoW’s other objection is just a strawman: ComEd never sought to publicize resource owners’ confidential data, any more than Section 16-115D requires the publication of confidential data with respect to ARES.

ComEd maintains that reducing uncertainty as to whether a generator qualifies as a “renewable energy resources” will improve the procurement process and will likely lower costs to participants and, ultimately, prices to customers. ComEd believes its revised proposal achieves those benefits while addressing in full the concerns with ComEd’s initial proposal raised by Staff and the IPA.

2. IPA's Position

The IPA agrees that the list of renewable resources is required to be updated. However, the IPA says the process for it to update the list of eligible renewable resources is governed by Section 16-115D of the PUA. The IPA says Section 16-115D of the PUA requires ARES to procure renewable resources in the same amounts as applicable to ComEd and AIC in Section 1-75 of the IPA Act. This section further provides that the renewable energy resource providers are to be independently verified through PJM-GATS and M-RETs. In addition, the IPA says no later than June 1, 2009, the IPA is required to provide PJM-GATs and M-RETS with "all information necessary to identify resources located in Illinois, within the states that adjoin Illinois or within portions of the PJM and MISO footprint in the United States that qualify under the definition of renewable energy resources under Section 1-10 of the Illinois Power Agency Act . . ."

The IPA says it updates the list of renewable energy resource providers on a recurring basis, as new facilities are developed. The IPA asserts that neither the IPA Act, nor Section 16-111.5 of the PUA requires the IPA to update the list for purposes of the procurement Plan. Therefore, the IPA believes the Commission should reject ComEd’s recommendation that the Plan identify some specified time or criteria for updating the list of providers.

In its Reply to Responses, the IPA states that under Section 1-75(c) of the IPA Act, the RPS standard that applies to ComEd and AIC, does not require that a resource be located in Illinois, adjoining states or the PJM or MISO regions. The IPA asserts that for it to publish such a list would require the IPA to qualify virtually every renewable resource facility operating in the United States for publication. Therefore, the IPA requests that the Commission reject ComEd's recommendation.

3. Staff's Position

Staff agrees that it would be beneficial for the IPA to provide participants in the renewable procurement process with a definitive list of generating facilities qualifying as renewable resources for the purposes of each planning year. Nevertheless, Staff is skeptical about the practicality of ComEd's proposal and disagrees with certain aspects of the proposal.

Staff is concerned that ComEd may be underestimating the task of compiling such a list for the IPA's procurement for ComEd and AIC. Staff indicates the list produced by the IPA for ARES' procurement of renewable resources is governed not only by the definition of renewable energy resources found in Section 1-10 of the IPA Act, but also by the provisions of Section 16-115D of the PUA, which applies only to the RPS for ARES. Section 16-115D sets forth the additional requirement that the resource must be located within Illinois and/or the PJM and MISO footprints. In contrast, Staff says as detailed in Section 1-75(c) of the IPA Act, the RPS for ComEd and AIC approaches the issue of resource location in a completely different way. Section 1-75(c) creates preferences for resources located within Illinois and states adjoining Illinois, but "if cost-effective resources are not available" from those preferred locations, "they shall be purchased elsewhere and shall be counted toward compliance." Staff asserts that arguably, "elsewhere" could be anywhere else in the world where there are generating facilities that meet the Section 1-10 definition of a renewable energy resource.

According to Staff, even if "elsewhere" were arbitrarily limited to anywhere else in the U.S., the task of listing qualified generation sources would still be quite difficult. The task would become even more difficult if the Commission accepts the IPA's proposal to procure renewable energy from so-called "distributed generation" facilities (like residential rooftop solar panels). Staff asserts such behind-the-meter facilities are much less likely to appear in databases maintained by REC tracking organizations, like PJM-GATS and MRETS, which Staff knows have been instrumental in enabling the IPA, to date, to create its lists for the ARES RPS.

Finally, Staff states that the RPS for ComEd and AIC (and the IPA) does not explicitly limit eligible resources to those that already exist in concrete form. Staff says the Commission has already approved one RFP for renewable energy resources that explicitly allowed lead-time for winning bidders to actually construct the facilities that would be identified in the contract. In Staff's view, it is not clear how the IPA would be able to identify all the resources that are still on the drawing board and transfer them to a list of eligible resources. Staff believes that if a list of facilities were to be created in advance of an RFP being issued, it should not be considered a "definitive" list, as proposed by ComEd.

Staff recommends that the Commission reject ComEd's proposal, but that the IPA take under advisement the general concept of producing a list of eligible (and/or ineligible) facilities in advance of issuing its renewable energy resource RFPs.

4. WoW's Position

In WoW's view, it is unclear what benefit ComEd's recommendation would provide, and what level of detail is to be included in the list. Wow says a similar list exists for the ARES. WoW claims the purpose of such a list for ARES was to ensure they procured their resources from acceptable or approved resources. WoW states that unlike the ARES, there is no restriction on the resources that could qualify for use as a renewable energy resource for utilities. According to WoW, while the IPA is to give priority to renewable resource facilities within Illinois and adjoining states, if there aren't enough megawatt hours of renewable energy resources from that area that have a price below the benchmark, then the IPA may select the lowest bids from renewable resource facilities from anywhere in the United States. In effect, WoW says the IPA would be making a list of all of the available renewable energy resources in the country.

In WoW's view, it is also unclear from ComEd's request whether information beyond simply identifying a plant would be included in the list of resources. WoW says if ComEd is interested in collecting and posting information that resource owners consider confidential, then further discussion of the issue will be needed. WoW does not support this proposal without a better understanding of its value to the process and the level of detail that is being requested.

5. Commission Conclusion

ComEd wants the IPA to prepare a list of generation sources qualifying as renewable resources under Section 1-10 of the IPA Act. The IPA, Staff, and WoW object to ComEd's proposal. In its Reply to Responses, ComEd makes a modification to its proposal intended to provide most of the benefits it associates with its proposal while eliminating most of the concerns identified.

The Commission is reluctant to adopt ComEd's recommendation that the IPA develop a comprehensive list of generating sources, over the objections of some parties, including the IPA, when there is no mandate the IPA develop the list proposed by ComEd. While there appears to be little doubt that ComEd's proposal, if adopted, would prove beneficial to some entities, the IPA has limited resources and the Commission finds that it would be inappropriate to require it to undertake this discretionary task over its objections. The Commission rejects ComEd's recommendation at this time; however, the Commission may be willing to revisit this suggestion in the future.

E. Recognition of Existing Long-Term Renewable Resources

1. ComEd's Position

ComEd states that while the Plan correctly acknowledges that the long-term renewable resources procured in December 2010 are a supply resource that should be taken into account in deriving the load volumes to be secured in the 2012 procurement cycle, the IPA proposes that the amount of those resources to be taken into account in the monthly MW requirements be calculated by applying an assumed annual wind generation profile to the annual delivery volumes for the long-term renewable PPAs.

ComEd says it has been unable to completely verify the profile proposed by the IPA, which shows unexpectedly low summer and peak generation percentages. ComEd also says that because the Procurement Administrator calculated a 0.98 Resource Factor for wind resources in the 2010 long-term procurement, ComEd was anticipating a more ratable production schedule. ComEd also notes that data from November 2010 appears to be missing or excluded from Table F of the Plan, Table Q is missing a column for Long-Term Renewable Energy (MW), and Table R is mislabeled as "Off-Peak" instead of "Peak."

Absent more data supporting the hypothetical wind profile included in the Plan, ComEd recommends the Plan be revised to reflect a value of 144 MW for both Peak and Off-Peak periods for ComEd's long-term renewable contracts (1,261,725 MWh ÷ 8,760 hours = 144 MW).

2. IPA's Position

The IPA recommends that the Commission approve the Plan as written. The IPA asserts that the Plan provides a detailed description of the calculation used in accounting for the long-term renewable resources. The IPA claims this methodology used PJM data that reported the wind-generated power outputs in the ComEd region for the May 2009 through April 2011 period and accounts for peak and off-peak variability as opposed to ComEd's fixed hourly long-term renewable contract volumes. The IPA finds it notable that AIC did not object to the Plan's proposal.

The IPA recognizes that ComEd also notes that data from November 2010 appears to be missing or excluded from Table F of the Plan, Table Q is missing a column for Long-Term Renewable Energy (MW), and Table R is mislabeled as "Off-Peak" instead of "Peak." The IPA says it will correct for these inadvertent errors.

3. Staff's Position

Staff believes the IPA could have done a better job presenting its data and its methods for creating the output profile found in the Plan. However, Staff contends that ComEd provides an explanation, neither for why it believes the IPA's summer and peak generation percentages are “unexpectedly low,” nor for why they would be inconsistent with the 0.98 resource factor calculated by the Procurement Administrator for the December 2010 procurement event. Staff says that combining PJM real-time LMP data for the ComEd zone for 2006 through 2009 with the IPA’s output profile, Staff finds that the weighted average value of the output would have been approximately 98% of the simple average LMP for that same time period.

Thus, while Staff shares ComEd’s concerns with the Plan’s presentation, Staff is less willing to share ComEd’s preference for its alternative single-value constant output profile. Staff says that alternative implies a “resource factor” of 1.0 rather than 0.98 (in other words, the expected weighted average value of the output would exactly equal the simple average of the prices paid).

4. Commission Conclusion

ComEd objected to the manner in which the IPA planned to estimate the wind profile for long-term renewable wind resources. The IPA responded to ComEd's objection and it appears ComEd did not further pursue the issue. Staff appears to support the IPA's methodology. In any event, the IPA asserts that it used the same methodology used by PJM and the Commission finds this approach to be reasonable for the 2012 Plan.

F. REC Procurement Process

1. Constellation's Position

In Constellation's view, although the Commission has made improvements between and among the REC procurements over the years, it could benefit from further streamlining. Constellation says previous year's REC procurements were held on different days, which was not optimal in that it resulted in different clearing prices for essentially the same product. Constellation adds that bidders were able to submit bids in the second procurement with knowledge of what had cleared in the first procurement. Constellation states that currently, REC bids are due on the same day and at the same time in two separate procurements, both using different forms. Constellation adds that bidders must determine how much to bid into each separate procurement event, once again resulting in the exact same product clearing at different prices. Given the nature of the product, Constellation believes there should be a single procurement process for both utilities, with the procurements linked, essentially acting as a single procurement. Constellation proposes that bidders would submit a single form and a single bid that would be applicable to both utilities. Constellation suggests the volumes for the winning bids would be split between ComEd and AIC proportionately, based on each utility's individual REC requirements procurements, thus resulting in procurements that would clear simultaneously and optimally.

2. Staff's Position

Staff believes that Constellation's proposal to streamline REC procurement is impractical as specifically presented, but worth exploring more generally. Staff suggests that if both ComEd and AIC had identical spending limits (per REC), then Constellation's proposal could be adopted, without significant difficulty. Staff says for choosing winning bids, the sum of the AIC and ComEd REC targets and the sum of their spending limits would be used. Staff adds that the RECs and their costs would be allocated, as Constellation suggests, on the basis of each utility's share of the total REC target, which would be equal to its share of the total REC spending limit. Staff notes however, that since the two utilities have different per-REC spending limits, and since these spending limits, as well as the statute's locational and resource type preferences must be taken into account during the selection process, a single consolidated RFP cannot be employed without considerable complexity. In addition, Staff asserts that Constellation's proposal takes for granted that suppliers, for the most part, are equally willing to sell to ComEd and AIC at the same price. Staff believes this may not be the case, especially if the ComEd and AIC contracts are not required to be identical. Of the two issues noted above, Staff believes the former is the more significant.

Staff provides an example intended to demonstrate the problems with Constellation's proposal. Staff concludes that merely splitting winning bidders' volumes in proportion to the ComEd and AIC REC targets is not feasible if we are to satisfy each utility's REC spending constraint. Staff contends that this becomes a complex process, when we also try to honor the statute's wind, solar, and locational preferences. Staff is cautiously optimistic that an algorithm could be developed that would be consistent with all these requirements. However, if the IPA's procurement administrators are unable to develop such an algorithm before the next REC RFP is issued, Staff believes the simultaneous-but-separate RFP process, which has been used for the last two plan cycles, will continue to suffice.

Staff recommends that the Commission reject Constellation's specific proposal for fully combining the AIC and ComEd REC procurements. However, Staff believes the IPA has the authority, in conjunction with its procurement administrators, to consolidate more thoroughly the AIC and ComEd REC procurements. Staff suggests this may include, for instance, accepting quantity bids that may be directed to one or both utilities. Staff recommends that the IPA put its consultants to the task of developing such a process for implementation this spring or at some point further in the future.

3. Commission Conclusion

Constellation proposes certain changes to the REC procurement process intended to streamline and improve the process. Staff objects to Constellation's proposal, arguing that it is impractical. It appears that Constellation did not reply to Staff's response.

The Commission has reviewed the parties' positions at finds that Staff has identified significant barriers to Constellation's proposal. While the Commission appreciates the input of Constellation and welcomes opportunities to improve the process, it appears Constellation views the REC procurement process in an overly simplistic manner. The Commission finds that Staff has identified significant problems with the implementation of the Constellation proposal and it will not be included in the 2012 Plan.

G. REC Target Volumes

1. WoW's Position

WoW states that the planning year projected total delivery volumes used in tables AA, BB, CC and DD differ from the load forecasts ComEd and AIC provided for the planning year 2012-2013. WoW says these differences have not been explained by the IPA. In addition, Wow indicates that the planning year delivery volumes for ComEd in the 2012 Draft Plan were 26,796,137 MWh and the IPA further reduced that number to 26,124,418. WoW believes that the volumes that should be used are the expected load numbers from the utilities five year forecasts, as reflected in the table below:

	AIC	**ComEd**
Tables AA, BB, CC and DD -- Planning Year Projected Deliver Volume (MWh)	14,389,577	26,124,418
Forecasted Planning Year Volume for 2012-2013 from Utilities Five Year Load Forecast (MWh)	15,306,901	28,376,378

WoW recognizes that the IPA is attempting to find a regulatory solution for load migration and is open to trying a reduced RRB, for the limited purpose of this procurement, to see how well it works. While WoW understands the 50% value to be an attempt to preserve a portion of the RRB for future procurements, WoW asserts that it is unduly constraining for AIC’s low load scenario. WoW says AIC is projecting an approximate 10% drop in load between 2012 and 2017 due to migration of customers to ARES, and while WoW could not find a low load scenario for AIC, it claims there are no facts supporting that its migration will approach a 50% value.

If it is the IPA’s intent to use this method in future procurements, WoW believes that the use of 50% of the RRB is unlikely to be a satisfactory long-term solution given the constraint the reduced RRB would place on larger procurement volumes that would occur in the future.

In its Reply to Responses, WoW notes that both ComEd and AIC assert that the Planning Year Delivery Volumes used in the 2012 Plan are correct. WoW states that the five-year forecasts provided by ComEd to the IPA are adjusted for line loss as well as demand side management. WoW claims could find no mention of line loss in the AIC forecasts. Based on the Responses of AIC and ComEd, WoW concludes the line loss adjustment must be the addition of line loss to the retail sales or metered data. WoW recommends that the Planning Year Delivery Volumes be provided by the utilities in their load forecast's used for procurement, as well as the factors (such as line loss, DSM and others) that account for forecasted load volumes. WoW suggests that providing this information will allow parties and intervenors to check that the correct energy amounts are used in the calculation of the renewable energy resource budget.

2. AIC's Position

AIC believes the IPA has correctly identified the calculation methodology in its Plan by stating "Additionally, the Planning year Projected Total Delivery Volume in the Tables reflect the aggregate projected portfolio minus losses. Lastly, as noted above, Rate Class DS/BGS-3A was declared competitive on May 1, 2011. In accordance with the statute, volumes representing the rate class have been removed from the following calculation yielding a smaller Base year volume for eligible retail customers in Table BB." AIC says WoW has seemingly ignored the above adjustment in coming to its conclusions.

AIC notes this same methodology has been used in previous Plans without objection. While WoW claims the IPA has provided no explanation for the difference, AIV believes the IPA has correctly referred back to the statute for the basis of RPS target volumes.

AIC states that "eligible retail customers" specifically excludes the load of customers whose service has been declared competitive, even though the load for those customers is permitted to be included within IPA energy and capacity purchases during the transition period. According to AIC, pursuant to the Order in Docket No. 11-0192, AIC customers with demands of 150 kW and above but less than 400 kW was declared competitive effective May 1, 2011. AIC adds that customers remaining on fixed price service may remain on such service through April, 2014. AIC insists the IPA has therefore properly excluded load requirements of these customers for purposes of calculating the RPS target volumes.

With respect to the calculation of the RPS target volumes at the customer meter, AIC believes it is again necessary to revisit the statute. At Section 1-75(c)(2) of the IPA Act it provides "the required procurement of cost effective renewable energy resources for a particular year shall be measured as a percentage of the actual amount of electricity (megawatt hours) supplied by the electric utility to eligible retail customers in the planning year ending immediately prior to the procurement." AIC says the "actual amount of electricity supplied by the electric utility to eligible retail customers" is expressed in terms of energy delivered through each eligible retail customers' meter.

In order to supply that actual amount of electricity to customers, AIC says the IPA must purchase enough energy and capacity to cover line losses. According to AIC, this is part of the reason why the total supply forecast is always slightly higher than the RPS target volumes, the other reason is the competitive declaration issue previously discussed. AIC asserts that prudently adjusting energy purchases to cover line losses in the total supply forecast does not change the wording in the PUA pertaining to the RPS target volumes which are to be calculated at the customer meter.

AIC states that Section 1-75(c)(5) of the IPA Act requires the ACP also apply to the utility's retail customers that take service pursuant to hourly pricing tariff or tariffs. AIC says the RPS requirements for customers served by an ARES or the utility's hourly pricing tariffs were designed to be competitively neutral with fixed price load. AIC believes that requiring fixed price load to also purchase a RPS requirement on energy losses would create a competitive advantage to other supply sources.

AIC is convinced the IPA has correctly chosen the proper methodology to calculate the RPS target volumes and the Commission should reject the WoW proposal.

3. ComEd's Position

In its Response to Objections, ComEd says WoW mistakenly suggests that the delivery volumes used in the Plan are incorrect. ComEd insists the 26,124,418 Planning Year Delivery Volume contained in Table DD of the Plan is correct. ComEd says it is based on the Expected forecast and is calculated in the same manner as all past procurement Plans. ComEd says the 28,376,378 MWh value cited by WoW is indeed the forecasted load for the 2012 Plan year. ComEd asserts that the renewables budget is based on the 2.015% cap on the increase in customer rates that is also imposed by the Act. ComEd states that customers' rates are based on sales or delivery volumes, which are calculated taking into effect line losses, and are therefore lower than the load values in the Plan.

ComEd believes the IPA appropriately employs a 50% reduction to the RRB to reduce (but still not eliminate) the risk that utilities are forced to contract for excess RECs and thereby burden customers with excessive costs. According to ComEd, WoW says this is overly conservative and urges the Commission to take greater risks with customers' money. If this recommendation is intended to apply to ComEd, ComEd believes it is ill-founded and should be rejected.

ComEd maintains there has been an increase in enrollments with ARES in recent months. ComEd also asserts that municipal aggregation, which is in its infancy and will result in even more customers switching away from ComEd's fixed price rates. While ComEd does not believe any additional long-term contracts are reasonable given the current acceleration of customer switching, it does believe the IPA's proposal to take a conservative approach in setting the long-term renewables budget, if any long-term renewables are to be procured at all, is warranted.

4. Commission Conclusion

WoW claims that the delivery volumes identified by the IPA are inconsistent with ComEd's and AIC's load forecasts. The IPA defers to the utilities, both of which contend that WoW is incorrect. ComEd and AIC each explain in detail why the delivery volumes identified by the IPA vary from those contained in the load forecasts.

While the IPA's presentation of its delivery could have been clearer, it appears to the Commission that WoW's concern is unfounded. The Commission finds that the delivery volumes identified by the IPA should be incorporated into the 2012 Plan.

H. Public Information Regarding Long-Term Renewables

1. Staff's Position

Staff recommends the Commission order the IPA to revise its Plan, so that the Plan includes certain information previously considered confidential by the Commission pertaining to the 2010 procurement of renewable energy resources via 20-year contracts. Staff states that in its 2009 procurement Plan for plan years beginning June 2010, the IPA proposed and the Commission approved the procurement of renewable energy resources via long-term contracts, where the winning bidders would supply AIC and ComEd with a “product” that bundled RECs and financial energy swaps, where the quantities of the bundled product would be tied to the output of specific electric generating facilities during the nominal period June 2012 through May 2033 (20 plan years). According to Staff an RFP and related documents were issued in the fall of 2010, and bids to supply this product were submitted and evaluated in December 2010. Staff says the results of the RFP were approved by the Commission on December 15, 2010 and posted on the Commission’s web site.

Staff indicates the information release did not include the specific quantities and average winning prices of wind RECs and the specific quantities and prices of solar RECs to be purchased, for fear that such product-specific information could indirectly reveal the winning bid prices of certain individual bidders, in potential violation of Section 16-111.5(h) of the PUA.

According to Staff, the information release also did not include the procurement administrators’ breakdown of the prices into their energy swap components and their REC components. To perform that breakdown, consistent with the IPA’s proposal and the Commission’s Order, Staff says the procurement administrators had to construct a forward energy price curve extending through May 2033, using it as a proxy for the energy swap price component of the bundled product. Staff says the REC price component in any given year was computed as the difference between the winning bid price of the bundled product (escalated to that year) and the forward energy price for that year. Staff asserts that the reason none of this information was released to the public in December 2010 is that in Docket No. 09-0373, the IPA proposed (and the Commission approved) maintaining as confidential the procurement administrators’ forward energy price curve. Staff claims the original rationale for maintaining confidentiality over the forward energy price curve was never articulated in Docket No. 09-0373 (nor is it articulated in the current Plan). Nevertheless, Staff did not oppose the IPA's proposal to keep the forward energy price curve confidential, since the information could conceivably have been construed by some bidders as being pertinent to the price benchmarks developed by the procurement administrators and employed to exclude bids above the benchmarks, or as being pertinent to Commission decisions to accept or reject bidding results. The possibility that bidders would attempt to draw such inferences, whether justified or not, and the possibility that this would influence bidding, with unknown consequences, was deemed by Staff to be a potential, albeit minor, concern. Staff believes that concern is now moot until next spring's procurement events, at which point the forward price curve from December 2010 will be at least 14 months old, and quite stale. Staff believes this information should be released now.

Staff says the rationale for releasing the product-specific (wind versus solar PV) price and quantity results is that this information is pertinent to each of the next 20 annual IPA procurement Plan proceedings. Staff believes interveners in procurement Plan cases have a legitimate need for this information, which otherwise would be known only to ComEd, AIC, the IPA and the Commission. Staff asserts that without the product-specific quantity information, nobody, other than ComEd, AIC, the IPA and the Commission, will know the extent to which the wind and solar PV goals of the IPA Act are being satisfied. Also, without the product-specific price information, Staff says nobody, other than ComEd, AIC, the IPA and the Commission, will know the relative cost of wind and solar PV resources. While there is still a risk that such information will indirectly reveal to the public the winning bid prices of certain individual bidders, Staff believes this risk is outweighed by the need of intervenors and the public to know the extent to which the individual wind and solar PV goals of the IPA Act are being satisfied and at what cost. It is Staff's position that the Commission can and should find that there is a "compelling demonstration of need" to release the information, as authorized by subsection 16-111.5(h) of the PUA.

According to Staff, the rationale for releasing the forward energy price curve developed by the procurement administrators for the 2010 long-term renewable RFP is that without this information, intervenors will have no idea how much of the total REC spending limit has already been reached and how much more can be spent during upcoming procurements. Furthermore, Staff says each year the Commission must post an ACP rate (for the State's RPS applicable to ARES) based on the utilities' expenditures on RECs. Hence, Staff believes release of this ACP rate information will have the same effect as releasing the forward energy prices, one year at a time. Finally, Staff claims that starting with the 2012-2013 compliance period, and continuing for one additional compliance period, this ACP rate must exclude the impact of the solar PV requirement. Staff contends that not only will the forward energy prices be revealed, individual product prices will also be revealed, unless the method of computing the ACP during these two years is kept secret, as well. Staff says that since there is no statutory requirement to maintain confidentially over the forward energy price curve developed by the procurement administrators for the 2010 long-term renewable RFP, one need not cite subsection 16-111.5(h). In Staff's view, the Commission can and should make a finding that there is a compelling need to release the information.

2. IPA's Position

The IPA disagrees with Staff and recommends that the Commission continue to treat the requested information as confidential. Staff recommends the Commission order the IPA to revise its Plan, so that the Plan includes certain information previously considered confidential by the Commission pertaining to the 2010 procurement of renewable energy resources via 20-year contracts. According to the IPA, the total quantity to be supplied and the corresponding average price of the winning bids approved by the Commission was posted to the Commission's website. Staff notes that the specific quantities and average winning prices of wind RECs and the specific quantities and prices of solar RECs to be purchased were not posted because of the fear that such product-specific information could indirectly reveal the winning bid prices of certain individual bidders, in potential violation of Section 16-111.5(h) of the PUA.

The IPA asserts that Staff provides no rationale for the Commission to ignore the IPA's obligations to maintain the forward price curve as confidential, and to reverse the Commission's Order in Docket No. 09-0373 to maintain the information as confidential. The IPA alleges that Staff even recognizes, Section 16-111.5(h) provides that only the "names of the successful bidders and the load weighted average of the winning bid prices for each contract type and for each contract term shall be made available to the public at the time of the Commission approval of a procurement event." The IPA is required to "maintain the confidentiality of all other supplier and bidding information." The IPA also says the Commission ordered that the forward price curve be maintained as confidential. (Docket No. 09-0373, Order, Appendix K at 3) The IPA also claims it was the expectation of the parties that bid on the long-term RECs that the forward price curve be maintained as confidential. The IPA also says Staff even acknowledges that parties could use the public disclosure of the forward price curve to influence the bidding of the long-term contracts, and that "there is still a risk that such information will indirectly reveal to the public the winning bid prices of certain individual bidders." According to the IPA, Staff only argues that because the forward price curve is now 14 months old, it is stale.

The IPA opposes Staff's recommendation. In the IPA's view, one of the hallmarks of the competitive bid process under the IPA Act and the PUA is that the benchmarks being used by the Commission to evaluate bids, and the price of the winning bids, be maintained as confidential. The IPA says Staff admits that the public disclosure of the forward price curve will disclose information that can be used to influence future bid activity. The IPA asserts that what Staff fails to acknowledge is that there are certain characteristics of the winning bids which, if disclosed, will disclose the winning bids, and therefore the relative value of the benchmarks, associated with the RECs. The IPA also claims the bids for these contracts were accepted by the Commission on December 15, 2010, less than one year ago. The IPA believes the information is not stale, and the prices associated with those renewable resources cannot be disclosed at this time.

The IPA does agree that at some point, market conditions, the IPA's subsequent procurement events, and the prices paid for wind and solar renewable resources will overtake the events of the December 2010 procurement event. However, the IPA believes the Commission should not release publicly the forward price curve associated with a procurement event that occurred less than 12 months ago.

In its Reply to Responses, the IPA notes that WoW asserts that the confidential information should be released so that interested parties (i.e., bidders) can develop recommendations on how to structure a portfolio of renewable products. The IPA continues to reject the notion that this confidential information should be released. The IPA believes the information that the parties seek to have released is the price curve, e.g., the IPA's forecasted short-term and long-term prices, for the renewable resources procured less than a year ago. The IPA will continue to develop a method of releasing information in a format that will allow an appropriate analysis of the remaining RRB. However, the IPA maintains it is premature to release the confidential forward price curve at this time.

3. WoW's Position

WoW notes that Staff recommends that certain information specific to the long-term renewable contracts procured in 2010 be made public. WoW supports that recommendation. WoW believes such information is beneficial for parties being able to develop recommendations on how to structure a portfolio of renewable products. WoW also believes Staff is correct in its statement that "intervenors will have no idea how much of the total REC spending has been reached and how much more can be spent during upcoming procurements."

4. ICEA's Position

ICEA supports Staff's recommendations to modify the Plan to release certain information previously held confidential. In ICEA's view, Staff provides ample support for why that information should now be released. ICEA agrees that this information is pertinent to each of the next 20 annual IPA procurement plan proceedings, and interveners in procurement Plan cases have a legitimate need for this information.

ICEA also believes the release of this information is supported by the fact that each year the Commission must post an ACP rate for the State's RPS, applicable to ARES based on the utilities' expenditures on RECs. ICEA agrees with Staff that release of this ACP rate information will have the same effect as releasing the forward energy prices, one year at a time. ICEA notes that Staff acknowledges that starting with the 2012-13 compliance period and continuing for one additional compliance period, this ACP rate must exclude the impact of the solar PV requirement. According to ICEA, not only will the forward energy prices be revealed, individual product prices will also be revealed, unless the method of computing the ACP during these two years is kept secret, as well.

ICEA agrees with Staff's arguments and rationale, and supports its specific recommendation to amend the Plan to include: (1) the expected aggregate imputed cost of RECs acquired through the December 2010 procurement event, for each utility, (2) the expected aggregate quantity of RECs acquired through that procurement event, for each utility and for each resource type (wind and solar PV), and (3) the IPA's energy market price forecast for the 20 years beginning June 2012.

5. Commission Conclusion

Staff recommends the Commission order the IPA to revise its Plan, so that the Plan includes certain information previously considered confidential by the Commission pertaining to the 2010 procurement of renewable energy resources via 20-year contracts. WoW and ICEA support Staff's recommendation. The IPA opposes Staff's recommendation, arguing it is premature to release the information. The IPA also expresses concern that the premature release of confidential information may compromise the success of future procurements.

As a general proposition, it is the policy of the State of Illinois that documents in the possession and control of State Agencies should be available for review by members of the general public. The Commission recognizes that there are exceptions to this general policy. In this instance, all parties appear to recognize that the information in dispute should be treated as confidential for some period of time and that it should be released for public view at some point. The issue before the Commission today is whether it is currently appropriate to release the information for public view.

Given the concerns raised by the IPA about the potentially adverse impact on future procurements, the Commission concludes that Staff's proposal to require the public release of certain information regarding long-term renewables should be rejected at this time. The Commission encourages the IPA to discuss with Staff and any other interested party the appropriate time for the public disclosure of the information at issue. In sum, the Commission finds that of the two completing interests here, the continued confidential treatment of certain information will contribute to future competitive renewable acquisition events.

I. ACP Rate

1. Staff's Position

Staff expresses a concern that the IPA Plan fails to explicitly establish the maximum ACP rate for the 2012-2013 Plan period, and fails to address the statutory requirement for ACP rates during the 2012-2013 and 2013-2014 Plan years to exclude any added cost of solar resources.

Staff asserts that there are numerous ways that one might choose to compute "the total amount of dollars that the utility contracted to spend on renewable resources, excepting the additional incremental cost attributable to solar resources." Staff proposes modifying the Plan to include a method. Staff sees several benefits to having this issue settled within this procurement Plan proceeding for the following reasons. First, by statute, the first step in establishing ACP rates is the annual procurement Plan. Second, the utilities' renewable energy portfolios included no solar resources prior to the Plan year beginning June 2012, and the "excepting" provision expires June 2014. Staff says the approved method would be in effect only for the two Plan years beginning June 2012 and June 2013.

Staff recommends the following method be adopted by the Commission. First, the total MWh of RECs being purchased for the compliance period and the total dollars contracted to be spent on those RECs would be summed separately for solar photovoltaic RECs and all other RECs ("non-solar RECs"). Staff says the average price of the selected non-solar RECs would be computed by dividing the dollars to be spent on the selected non-solar RECs by the total number of non-solar RECs under contract. Under Staff's proposal, this average price (which effectively excludes any incremental cost attributable to solar resources) would be multiplied by the total number of RECs purchased (both solar photovoltaic and non-solar). To obtain the ACP rate, Staff says this product would be divided by the forecasted load of eligible retail customers, at the customers' meters. Staff provides a hypothetical example to demonstrate the calculations.

2. IPA's Position

The IPA notes that Staff proposes modifying the Plan to include a method for establishing the maximum ACP rate for the 2012-2013 Plan period and does not address the statutory requirement for ACP rates during the 2012-2013 and 2013-2014 Plan years to exclude any added cost of solar resources. The IPA disagrees with Staff's suggestion to include a methodology to address the ACP. The IPA claims there is no statutory mandate that this be included in the Plan. According to the IPA, the ACP payments and calculations do not have any effect on the prices paid by eligible retail customers. The IPA says it will continue to work with Staff to develop the rate outside of Plan.

3. ICEA's Position

With regard to Staff's proposal establishing the maximum ACP, ICEA fully supports the proposed method, which ICEA believes is required for the Plan to comply with the PUA.

4. AIC's Position

In its Response to Objections, AIC agrees with Staff's proposal for establishing the ACP for the 2012-2013 Plan years and recommends it be included in the Plan.

5. Commission Conclusion

Staff expresses concern that the IPA's Plan fails to establish the maximum ACP rate for the 2012-2013 Plan period, and fails to address the statutory requirement for ACP rates during the 2012-2013 and 2013-2014 Plan years to exclude any added cost of solar resources. Staff provides a method that it recommends the Commission adopt for establishing the ACP rates during the 2012-2013 and 2013-2014 plan years, when the ACP rate must exclude added costs of solar resources. Staff's proposal is endorsed by AIC and ICEA. The IPA claims there is no statutory mandate that this be included in the Plan, that the ACP payments and calculations do not have any effect on the prices paid by eligible retail customers, and that it will continue to work with Staff to develop the rate outside of Plan.

While Staff raises an important issue, it does not appear to the Commission that there is any requirement for establishing a methodology for computing actual ACP rates during the 2012-2013 and 2013-2014 Plan years. As a result, the Commission declines to do so.

J. Contingency Planning For REC Supplier Default

1. ComEd's Position

Section 3.3.3.3 of the Plan contemplates securing replacement RECs in the event of a supplier default. The Plan states that "[t]o accommodate replacement REC purchases, the IPA proposes to extend the allowable vintage ranges for complying RECs within the terms of the supply contracts negotiated in the 2012 procurement cycle. In the event that replacement RECs are purchased by the Utility due to a default, the Utility will first use the collateral on hand from the defaulting supplier to satisfy costs associated with securing replacement RECs." ComEd believes the proposal to extend vintage ranges is vague and would recommend this be clarified. To do so, ComEd proposes that the time frame for delivering such replacement RECs and their vintage be extended by three months.

Similarly, while ComEd agrees that supplier collateral held for the defaulting party should be taken and used to offset the costs of the replacement RECs, ComEd believes it is still unclear as to what happens if such collateral is insufficient. If the full amount of replacement RECs need to be purchased regardless of cost and amount of collateral held, the Plan should make that clear. If the targeted number of RECs procured are to be reduced, ComEd says the Plan should so specify.

In its Response to Objections, ComEd indicates that it agrees with Staff's proposal on this issue. ComEd believes this is an appropriate and fair means by which to procure targeted RECs without incurring additional costs related to any extra procurement(s), which would ultimately harm consumers. The one clarification that

ComEd would propose is to make clear that any collateral would need to be retained, used, or returned consistently with the underlying REC agreement.

In its Reply to Responses, ComEd states that it and AIC, both concluded that Staff's alternative was superior to the original IPA proposal and recommend it be approved. ComEd says the IPA instead proposed a clarification to its original proposal. ComEd asserts that the IPA's revised language makes it clear that, in the event of default, the utility "will purchase replacement RECs up to the cost of the defaulted contract value." ComEd believes the proposal remains unclear about how "the allowable vintage ranges for complying RECs would be extended." ComEd also states that it does not make clear what happens if the collateral is insufficient. ComEd says the IPA also does not come to grips with AIC's concerns about the proposal's legality. While ComEd takes no position on that argument, ComEd does believe that all other things being equal, proposals raising serious legal challenges should be avoided.

For these reasons, ComEd urges the Commission to approve the Staff alternative.

2. AIC's Position

The IPA proposes contingencies in the event of supplier default on renewable energy contracts for any given plan year. The IPA further states that it does not interpret the statute to allow the transfer of Renewable Resources Budget funds between compliance years. Under the proposal, the first contingency would be applicable if the contract volume associated with the default is under 5% of the annual RPS obligations. In this case, the IPA proposes that the utility request price proposals from the other vendors supplying RECs in that compliance year. The utility would first use collateral on hand from the defaulting supplier to satisfy costs associated with the replacement RECs. The second contingency would be applicable if the contract volume associated with the default is greater than 5% of the annual RPS obligation. In this case, the IPA would solicit bids from all firms deemed qualified as REC suppliers in the most recent REC solicitation. Again, the utility would first use collateral on hand from the defaulting supplier to satisfy costs associated with securing replacement RECs.

AIC states that the supplier default may occur late in the planning year or even after the planning year and under such a scenario, it may be difficult to acquire replacement RECs associated with the planning year for which the default occurred. It appears to AIC that the IPA has attempted to address this issue under a proposal to extend the allowable vintage ranges for complying RECs within the terms of the supply contracts negotiated in the 2012 procurement cycle. AIC says it is not clear if this is the IPA's intent, nor is it clear if the proposal is consistent with the RPS.

With regard to the IPA's proposal that the utilities procure replacement RECs in the event such quantities are less than 5% of the annual RPS obligations, AIC believes this is counter to previous Plans because the solicitation would not be managed by the IPA and its procurement administrator. According to AIC, the IPA Act clearly identifies the IPA as the entity that will make procurements on behalf of AIC. AIC states that though the desire of the IPA to minimize costs associated with a replacement REC solicitation for what would be a small quantity of the yearly renewable target has merit, the proposal for AIC to manage such a solicitation has no basis in legislation. AIC also claims this is consistent with the Commission conclusion pursuant to the 2011 Plan, whereby the Commission found that if a new RFP must be issued, the Commission considers it appropriate for any replacement short-term RECs to be procured by the IPA.

With regard to the procurement of replacement RECs where defaulted quantities are less than 5% of the target, AIC finds the proposal unclear. AIC says there is no discussion whether cost benchmarks would be used and if so, how they would be established. AIC also says if cost benchmarks are not established, it is unclear if replacement RECs would be purchased at any price. AIC states that it is also unclear if replacement RECs would be subject to the RRB. Depending on the IPA's intent with regard those issues, AIC is concerned that by limiting the pool of suppliers to those that were winning suppliers in the planning year, it is possible that only one (or two) suppliers could exist. If that were the case, AIC believes this could provide an opportunity for suppliers to unilaterally set the price of replacement RECs. AIC believes these are critical issues that were not addressed in the Plan.

If the Commission determines the IPA should solicit replacement RECs due to supplier default, AIC recommends the Commission order the IPA to manage solicitations for replacement RECs regardless of quantity. Furthermore, AIC believes any such solicitation should be subject to cost based benchmarks and the RRB, and should be solicited from the universe of available suppliers, not just those for which AIC has existing contracts.

In its Response to Objections, AIC indicates it is not clear if Staff's proposal is consistent with the RPS because the RRB appears to apply to each planning year independent of the other, with no provision to carry forward funds to a future year. AIC says doing so would effectively increase the RRB for the future year.

AIC believes the Staff proposal represents an improvement to that proposed by the IPA, especially the removal of the recommendation that AIC be responsible for solicitations of replacement RECs if the quantities were less than 5% of the annual RPS. AIC says such a solicitation would have been without statutory authority and AIC is therefore in agreement with Staff in this regard. However, AIC suggests that some of the previously mentioned details in the Staff proposal, while they appear to be well thought out and capable of being implemented, should be considered in the context of what the RPS allows prior to implementation.

In its Reply to Responses, AIC indicates that the IPA recommends that contracts with REC suppliers be modified in such a manner to permit AIC to purchase replacement RECs as cover damages arising from default. The IPA continues by stating that replacement RECs would be purchased up to the aggregate cost of the

RECs in default, satisfying the renewable resource budget. Moreover, the Plan proposes that the utilities first obtain replacement RECs from bidders that were successful in the spring 2012 procurement event, under the same price terms as set by the procurement event, thereby satisfying that any replacement RECs be priced below the confidential benchmarks.

AIC states that existing REC contracts contain default provisions which reference AIC's right to collect a settlement amount based on market losses, liquidated damages. AIC suggests as a practical matter, this clause does not ensure that such losses will be collected because the defaulting party may be in bankruptcy. AIC believes it is not clear to that the IPA proposal to change the contract terms provides any additional protection relative to existing contracts.

AIC also believes it is import that it can find no statutory authority by which it could administer any solicitation, even a small solicitation as proposed by the IPA. AIC reiterates that this responsibility falls to the IPA and that the Commission agreed by stating if a new RFP must be issued, the Commission considers it appropriate for any replacement short-term RECs to be procured by the IPA.

If the Commission desires to address the issue of procurement of defaulted RECs in this Plan, AIC believes that Staff has offered the best proposal, but this is primarily because the Staff proposal has correctly eliminated the role of AIC in regards to the procurement of defaulted RECs. AIC maintains that it is not clear if two components of the Staff proposal are consistent with the RPS. The first is the proposal to carry over defaulted RECs to the following proximate year and the second is the proposal that any dollar amounts that were not spent due to the default, plus any additional collateral retained by AIC due to the default, shall be added to the REC budgets for the subsequent plan year. Under both proposals, AIC says a default in one year impacts the subsequent year and doing so may not be consistent with the RPS. When considering the magnitude of disagreement regarding this issue, AIC suggests the better course of action is to allow the parties to explore the use of defaulted RECs before the next Plan, in the hope of finding common ground supported by the law.

3. Staff's Position

In Staff's view, the Plan for when the contract volume effected by the default represents greater than 5% of the annual RPS obligation should be eliminated. Staff believes it is unclear it the IPA intends to solicit these bids, by itself, or with the aid of a Procurement Administrator. Staff also believes it is unclear if the IPA intends for the solicitation to be monitored by a Commission Procurement Monitor and for the bidding results to be approved by the Commission. If so, Staff claims this would add significantly to the cost of the solicitation and could easily render it a tremendous waste of resources.

Staff also believes the Plan for when the contract volume effected by the default represents less than 5% of the annual RPS obligation should be eliminated. Staff claims that one problem with the proposal is that it provides too little guidance to the utility and virtually no oversight. Staff asserts that, it creates the potential for the utility to choose the winning replacement REC suppliers in a discriminatory manner. In Staff's view, even the appearance of such impropriety should be avoided.

Staff proposes the following language be included in Section 3.3.3.3 of the Plan for material instances of supplier default on renewable energy contracts:

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

4. IPA's Position

The IPA believes that the contracts with the defaulting REC suppliers can be modified to permit AIC and ComEd to purchase "replacement" RECs as cover damages arising from the default, while still complying with the legislative direction that the IPA manage the procurement event that leads to those contracts. To clarify this point, the IPA recommends that the Plan be modified at page 57 to state as follows:

> <u>The REC contracts will provide that it will be an event of default for the REC suppliers to fail to deliver RECs in accordance with the contract, and that the utility, as cover damages for the default, will purchase replacement RECs up to the cost of the defaulted contract value (if less than 5% of the RPS.) In such event, the Utility will report the default to the Commission and the IPA. To satisfy its cover damages,</u> the Utility will request price proposals from the other vendors supplying RECs in that compliance year for replacement RECs . . .

According to the IPA, the replacement RECs would be purchased up to the aggregate cost of the RECs in default, satisfying the renewable resource budget. The IPA also says the Plan proposes that the utilities first obtain replacement RECs from bidders that were successful in the spring 2012 procurement event, under the same price terms as the set by that procurement event, thereby satisfying that any replacement RECs be priced below the confidential benchmarks. The IPA believes with these clarifications, that the noted concerns have been addressed.

In its Reply to Responses, the IPA indicates that AIC and ComEd support Staff's proposal submitted on October 3, 2011. The IPA says its proposed alternative language in the October 18, 2011 Response to Objections addresses the concerns raised by AIC, ComEd, and Staff, and provides a more workable solution that is consistent with the IPA Act. The IPA says AIC, for example, notes that Staff's proposal to carry forward any dollar amounts that were not spent due to a default to the following year. AIC notes further that it is unclear whether this is consistent with the IPA Act. The IPA states that its proposal would require the utilities to use unspent funds to procure replacement RECs in the year of the default, satisfying AIC's concerns in a manner that is consistent with the IPA Act.

Therefore, the IPA requests that the Commission adopt the IPA's proposed alternative language set forth in its October 18, 2011 Response to Objections.

5. WoW's Position

In its Reply to Responses, WoW notes that the IPA proposed additional language in its Response to Objections. According to WoW, the IPA's proposed language raises two issues. First, WoW asserts that allowing the utility to meet its statutory requirement with less than the statutory requirement and dollars left in the RRB starts us down a slippery slope of allowing the utilities to meet their requirement amount with less than the number of renewable energy resources to fully meet the requirement. Second, WoW believes it is unclear whether the IPA intends to require successful bidders to provide replacement RECs for the same bid price they submitted for the 2012 procurement.

WoW says the IPA's additional language revises the replacement REC methodology and would result in the number of replacement RECs not being equal to the number of defaulted RECs. WoW indicates that while it does not object to this process being used in this year, since the volume of RECs being discussed is relatively small, this proposal is not consistent with the statute. In Docket Nos. 07-0528/07-0531 and Docket No. 07-0527, the issue of how to prioritize RECs was addressed. WoW says that in both Orders, the Commission concluded that the priority of the statute is (1) achieving the required level of renewable energy resources within the cost cap; (2) meeting the locational requirements; and (3) meeting the percent wind requirement. According to WoW, the Commission's order of priority for renewables would lead one to conclude that the procurement of replacement RECs should not be indirectly capped by the collateral associated with the defaulted RECs, but should be capped by the RRB.

WoW does not object to the implementation of this proposal for the 2012 procurement, given the small amount of RECs in question, but reserves the ability to challenge this proposal in future procurements. WoW is concerned this methodology starts down a slippery slope of allowing the utilities to meet their requirement amount with less than the statutory requirement and dollars left in the RRB.

In WoW's view, it is unclear whether the IPA intends to require successful bidders in the Spring of 2012 to provide replacement RECs or if the proposal is to just give those bidders the first option to provide replacement RECs at the bid price they submitted. The 2012 Plan states that the utility will request price proposals from the other vendors supplying RECs in that compliance year for replacement RECs of the same vintage and specifications of those the defaulting vendor has failed to deliver. WoW recommends that the interpretation be consistent with the language in the 2012 plan – that it give the winning bidders the first option to provide replacement RECs. If the IPA now intends to require the bidder to provide the REC at the bid price, WoW says that would require a bidder to hold open a price and quantity of RECs for an unknown period of time. WoW believes that increases risk to the seller and would increase the bid prices for renewable energy resources.

WoW suggests that if the Commission approves a multi-year REC procurement, instead of a one-year REC procurement, the IPA's additional language would require a bidder to provide a replacement REC in 2015 at the price it submitted in 2012. WoW believes such a requirement is overly burdensome and can be avoided by adopting WoW's position.

6. Commission Conclusion

Both Staff and the IPA provided suggested language to modify this portion of the Plan. Staff's proposal is endorsed by both ComEd and AIC as superior to the IPA's language. WoW, while not specifically objecting to the IPA's proposal, raises concerns about the potential impact on future procurements.

The Commission finds that Staff's proposed language is superior to the IPA's alternative. Among other things, the IPA's alternative language remains somewhat unclear as the other parties suggest. Additionally, Staff's proposal properly removes the utilities from the process of procuring replacement REC in the event of default. In summary, the Commission approves for inclusion in Section 3.3.3.3 of the 2012 Plan, the language recommended by Staff.

K. Contingency Planning For Significant Load Shifts

1. Staff's Position

Staff believes that the language in the Plan for portfolio rebalancing in the event of significant shifts in load is too narrowly focused on customer switching that is expected due to municipal aggregation programs. While Staff believes the language in the Plan is an improvement over the language that was in last year's procurement plan, Staff is concerned that this contingency plan is too narrowly focused on customer switching that is expected due to municipal aggregation programs. Staff says while it may be true that this is recently a significant driver of load changes, it is not the only driver of load changes. Staff believes other drivers would include customer switching to ARES (rather than municipal aggregation), macro-economic shifts, and significant energy price changes. Staff complains that the IPA provides no explanation for why it would intervene only in the special case of customer switching that is expected due to municipal aggregation programs.

In addition, Staff believes certain aspects of the IPA's proposed contingency plan are still too vague, such as the provision for AIC to revise certain data "[p]rior to the procurement event." If it is revised one day prior to the procurement event, Staff says it will be too late to incorporate into the procurement event. If it revised four months prior to the procurement event, Staff avers it may miss three months of subsequent developments.

Finally, Staff supports the IPA's commitment to "work with" AIC, Staff, and the Procurement Administrator and Monitor to determine if the planned purchase quantities should be changed. This provides the flexibility that Staff believes is necessary. However, Staff recommends that the actual decision to change those quantities, if it is not practical to bring the matter before the Commission, should be dependent upon a consensus of those five parties.

Staff provides specific proposed language that it believes should be used to modify the Plan.

In its Reply to Responses, Staff indicates that the IPA and AIC agree with Staff's proposed changes to the Plan's provisions for rebalancing the portfolio in the event of significant shifts in load. AIC's concurrence with Staff is contingent upon removing the word "energy" from one sentence. Staff agrees that this is an appropriate modification.

Staff notes that ComEd argues that it is unlawful for a change in the portfolio quantities to be determined through a consensus of the IPA, Staff, the Procurement Administrator and Monitor, and the utility. ComEd explains that this is because the PUA unambiguously requires that the Commission review and approve not just the Plan generally, but that the Commission shall approve the procurement Plan, including expressly the forecast used in the procurement Plan. ComEd concludes that changes, if any, to the quantities of power called for by the Plan must be limited to circumstances that can be objectively defined and therefore reviewed and approved by the Commission with the Plan itself. According to Staff, ComEd opines that municipal aggregation is just such an objectively defined circumstance, and recommends that it alone be the circumstance that may trigger portfolio rebalancing during Plan implementation.

ComEd is correct that pursuant to Section 16-111.5(d)(4) of the PUA, the Commission must approve the forecast used in the plan. Staff believes that a change in the forecasted quantity demanded due to municipal aggregation is fundamentally the same as a change in the forecasted quantity demanded due to other well-defined inputs used in the forecasting process. In Staff's view, ComEd's proposal is no more in sync with the PUA than Staff's proposal, if the word "forecast," in Section 16-111.5(d)(4) of the PUA, refers to the actual quantities that are forecasted. Staff suggests that if the word "forecast" instead refers to the mathematical models and methods used to derive forecasted quantities, then both the ComEd and Staff proposals may be considered equally consistent with the PUA. In Staff's view, the latter interpretation of the PUA is the proper interpretation. That is, to the extent to which there would be any controversy over a forecast used in a procurement plan, Staff says it would be a dispute about the mathematical models and methods used rather than the output of those models and methods. For example, Staff believes one cannot reasonably argue against a forecasted quantity of 13,000,000 MWh on the grounds that "thirteen is an unlucky number." Staff believes the Commission properly should be resolving disputes over models and methods and not over numbers.

Staff also asserts that the requirement in the PUA that the Plan include procedures for balancing loads, including portfolio rebalancing in the event of significant shifts in load implies that, between Plans, significant changes in forecasted quantities must be identified and dealt with. If the IPA is barred from considering forecasted quantity changes during Plan implementation, Staff wonders how changes in load could be dealt with, except through subsequent Plan proceedings. Staff believes changes in forecasted quantities, derived in a manner consistent with the Commission-approved forecasting models and methods, logically must be authorized by the PUA.

2. AIC's Position

The IPA proposes that prior to the procurement event, AIC will true-up its forecasted amount of customer switching that is expected due to municipal aggregation programs. AIC is to also survey the actual number and size of the municipalities that have at that time filed with the relevant election authority to hold, or have already passed referenda approving "opt out" aggregations. As AIC understands, it is required to report the results to the IPA who will work with AIC, Staff, and the Procurement Administrator and Monitor to rebalance the portfolio commensurate with the change in forecasted customer switching due to municipal aggregation programs.

AIC indicates it does not object to this proposal to provide a trued up forecast, however AIC points out that in previous Plans, the section titled "Portfolio Rebalancing in the Event of Significant Shifts in Load" addressed the time period after the procurement events. AIC also notes Attachment A, which contains its load forecast report, includes language that assumed the methodology used in previous Plans would continue in this Plan. AIC says that Attachment A provides that during the active delivery year of 2012 and in the event that AIC's energy forecast increases above the high forecast or decreases below the low forecast, AIC shall promptly notify the IPA. AIC says it further provides that the IPA will subsequently convene a meeting with AIC, Staff, and the Procurement Administrator to determine whether it is appropriate to rebalance the portfolio, and if so, to what extent and how such a rebalancing can be achieved. If the Commission agrees with the IPA, AIC requests acknowledgement that the language in Attachment A no longer apply to this Plan.

In addition, AIC says the IPA proposal primarily references the impact of municipal aggregation programs based on a survey of municipal aggregation programs that have "opted out." AIC states that municipal aggregation, while appearing to gain momentum within its service area, currently lags that seen within ComEd and therefore may limit the ability of AIC to true-up the forecast based on municipal aggregation that may not exist at the time of the true up. AIC indicates that it envisions a scenario where instead the forecast true-up in early 2012 would be driven primarily by retail switching activity associated with individual customer load as opposed to less than robust survey results pertaining to municipal aggregation. AIC requests the Commission acknowledge the differences between ComEd and AIC in this regard and that AIC will use the best data available associated with this forecast true-up in early 2012, whether it is switching statistics, surveying of municipal aggregation, or some other combination.

In its Response to Objections, AIC indicates that it generally agrees with Staff on this issue. That being said, AIC recommends the Commission consider a change to the language as proposed by Staff. Specifically the word "energy" should be removed from the following sentence: "revise the volumes of energy products that will be sought through the spring procurement events, but only if a consensus is reached." AIC believes that doing so will clarify that "volumes" could include energy, RECs, or capacity in the event the Staff, IPA, Procurement Administrator and Procurement Monitor reach consensus.

In its Reply to Responses, AIC interprets the current proposal in the Plan to include three forecast updates. AIC suggests minor suggestions to the proposals made by the IPA as they relate to forecast updates and portfolio rebalancing intended to provide improvement. AIC interprets that it has three requirements under the IPA proposal.

AIC states that ComEd believes that the IPA's original and more limited proposal specific to the effect of municipal aggregation is more in keeping with the language and spirit of the PUA. AIC restates its desire to use a combination of municipal aggregation data and switching statistics given the relative infancy of municipal aggregation in the AIC service territory when compared to that of ComEd. AIC says this is consistent with the revised IPA proposal. AIC supports the revised proposal by the IPA.

3. ComEd's Position

Staff proposes several modifications to the Portfolio Rebalancing sections of the Plan. Staff expresses concern that the IPA proposal is too focused on customer switching that is expected due to municipal aggregation programs. Staff also proposes language that would authorize rebalancing if consensus is reached between the IPA, Staff, the Procurement Monitor, the Procurement Administrator, and the utility. ComEd believes that Staff's proposal is inconsistent with the PUA.

According to ComEd, the PUA prescribes a particular and specific process for determining the amount of energy that the IPA is to procure. ComEd says it requires utilities, like ComEd, to develop a forecast and requires the IPA to set out the amount of energy it proposes to procure in the power procurement Plan it files with the Commission. ComEd claims the PUA then gives all stakeholders an opportunity to review and have input into both the forecast and the Plan. ComEd asserts that it then requires that the Commission review and approve not just the plan generally, but that the Commission shall approve the procurement Plan, including expressly the forecast used in the procurement Plan. In ComEd's view, given this statutorily prescribed process, changes, if any, to the quantities of power called for by the Plan must be limited to circumstances that can be objectively defined and therefore reviewed and approved by the Commission with the Plan itself.

ComEd believes that the IPA's more limited proposal specific to the effect of municipal aggregation is more in keeping with the language and spirit of the PUA. ComEd states that under the IPA proposal, the Commission knows in advance and, thus, can review and approve this specific circumstance as one triggering rebalancing and knows how change in energy purchases would be ascertained (i.e., by the effect of municipal aggregation). ComEd claims this proposal is also consistent with history. ComEd asserts that customer switching historically has been the cause of the only circumstance where rebalancing was required. ComEd says that due to significant customer switching that was forecasted to occur, the IPA rebalanced the portfolio that was approved by the Commission for last year in Docket No. 10-0563. While customer switching is impacted by both municipal aggregation programs and ARES switching, ComEd claims we now have a history of ARES switching, while municipal aggregation is more uncertain and potentially more problematic. In ComEd's view, it is more appropriate to focus solely on customer switching forecasted to occur by municipal aggregation.

In its Reply to Responses, ComEd states that as in past years, the IPA proposed a means to rebalance portfolios in the event that specific events occur, especially unforeseen municipal aggregation. ComEd also says Staff's Objections suggested instead that rebalancing be authorized when "consensus is reached" between the IPA, Staff, the Procurement Monitor, the Procurement Administrator, and the utility. ComEd's Response pointed out that this Staff's proposal was likely inconsistent with the PUA's requirement that the Commission approve the forecast and the Plan, including the amount of energy to be procured. As ComEd noted, the PUA then gives stakeholders an opportunity to have input into the forecast and Plan, but clearly and unavoidably mandates the Commission itself "approve the procurement plan, including expressly the forecast used in the procurement plan . . . ."

ComEd notes that AIC accepts Staff's proposal, but, in contrast, provides no analysis of whether allowing parties other than the Commission to modify the forecast -- based on their own "consensus" and without limitation to a Commission-defined circumstance (i.e., excess municipal aggregation) -- constitutes an unlawful delegation of discretion. In ComEd's view, that is a needless legal risk to which the Commission should not expose this critical process. ComEd believes the IPA's original proposal, which identified the circumstances under which rebalancing would occur, is the safest and best course.

In response to another suggestion from AIC, ComEd says the IPA also now offers to revise that plan by having two rebalancing events, one before and one after the procurement event. ComEd believes this is unnecessary and needlessly complex, especially given that the Plan already calls on ComEd to submit an updated load forecast. ComEd says if significant unforeseen and unforecast changes in load requiring rebalancing do occur, there is no reason why they cannot be addressed by a single rebalancing, as provided in past years' Plans, or why they cannot be addressed in the next annual procurement event. ComEd also believes it is unclear how a post-event rebalancing would accomplish any purpose. However, if the IPA and AIC remain concerned about the situation in AIC's territory and MISO, ComEd suggests at a minimum that the double-rebalance proposal be restricted to AIC.

ComEd also notes that AIC proposes a wording change to the IPA's original language, deleting the word "energy" from one provision so as to make clear that rebalancing can also include capacity and other products. ComEd has no objection to this clarification.

4. IPA's Position

In its Response to Objections the IPA says it wishes to clarify that it does not intend to delete the language in Attachment A, which governs the process in the event that there is a material shift in load after the procurement event. According to the IPA, the Plan proposes an additional trigger to account for a shift in load that is recognized by the utilities from the time that Commission approves the Plan in December 2011, and the procurement event in the spring of 2012. To clarify this proposal, the IPA recommends that the language at pages 38 (AIC) and 47 (ComEd) be revised as follows:

> The PUA requires that the IPA provide the criteria for portfolio rebalancing in the event of significant shifts in load. Over the term of this Plan, the most significant driver of load shifting levels is customer switching. <u>In the event that AIC's [ComEd's] annual forecast increases above the High Forecast or decreases below the Low Forecast during the active delivery year of an approved Procurement Plan, Ameren [ComEd] shall promptly notify the IPA. The IPA will subsequently convene a meeting with AIC [ComEd], Commission staff, and the procurement administrator to determine whether it is appropriate to rebalance the portfolio, and if so, to what extent and how such a rebalancing can be achieved</u> . . . .

The IPA notes that AIC seeks Commission acknowledgment that its municipal aggregation impacts may not be as aggressive as ComEd's, and its forecasts will likely be affected more by retail switching activity associated with individual customer load as opposed to municipal aggregation. As such, AIC commits to using the best data available associated with this forecast true-up in early 2012, whether it is switching statistics, surveying of municipal aggregation, or some other combination. The IPA's goal of the rebalancing provision was to understand the impact of customer migration, be it from municipal aggregation or other factors such as retail customer switching. The IPA notes that Staff sought clarification on this issue and provided suggested language to further develop this issue.

Subsequently in its Response to Objections, the IPA says it agrees that there are other factors affecting load changes. The IPA did not intend to limit the portfolio rebalancing to shifts in customer switching due solely to municipal aggregation. As such, the IPA agrees that the language needs to be further clarified as suggested by Staff. Specifically, the IPA agrees with the following modifications to page 38 and 47 of the Plan, adjusted accordingly for each utility:

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

5. WoW's Position

WoW notes that in its Objections, Staff recommends that the utilities be allowed to provide revised load forecasts in March of 2012. WoW also notes that in its Response to Staff's Objections, the IPA agreed to Staff's recommendation and provided replacement language. WoW states that if the revised load forecasts to be submitted by the utilities in Spring 2012 changes the procurement volumes the Commission should issue an order consistent with its Docket No. 08-0519 Order and in compliance with Section 16-111.5(4) of the PUA.

6. Commission Conclusion

Several parties raised concerns with the IPA's proposal for dealing with the possibility of significant load shifts. Staff proposed specific language changes intended to address its concerns. ComEd endorses the IPA's original proposal and suggests Staff's proposal is inconsistent with the statute.

While the Commission understands ComEd's position, it is not clear that the IPA's original proposal, which ComEd endorses, is superior to Staff's from a legal perspective. The Commission also believes that to the extent ComEd is correct that for its service territory, municipal switching is the most likely source of significant load shifts, the Staff proposal would, as a practical matter, have no adverse impact on the procurement process. Having reviewed the parties' positions, the Commission therefore finds that the 2012 Plan should be modified to include Staff's proposed language, as modified by AIC. The Commission is convinced that it is a more robust proposal for dealing with possible significant load shifts, which by law, must be addressed in the Plan. The Commission also believes that ComEd has raised a valid concern that the IPA's proposed amendment to its original proposal is overly complex. The Commission believes this concern supports the decision to adopt Staff's proposal, as modified by AIC.

L. Capacity Purchases

1. Staff's Position

Staff has no objection to the IPA's proposal to acquire capacity for AIC for the proximate 2012-2013 planning year. However, given the current state of flux acknowledged by the IPA, Staff sees no reason to use the spring 2012 procurements to secure capacity for AIC for the 2013-2014 and 2014-2015 planning years. According to Staff, looking forward to plan years beginning on and after 2013-2014, it is unclear why the IPA proposes that AIC continue to obtain capacity through IPA procurement events rather than through the forward capacity market that MISO has proposed to implement. Staff states that while the Plan (and all IPA plans, to date) called for ComEd to satisfy capacity requirements through participation in the PJM forward capacity market, the IPA has apparently rejected, for reasons not stated, this approach for AIC in a MISO forward market similar to the PJM structure.

Staff objects to the IPA's plan to purchase capacity for AIC during spring 2012 for plan years 2013-2014 and 2014-2015. Staff recommends modifying the Plan to include capacity purchases for AIC only for the June 2012-May 2013 Plan year. Staff suggests that if the IPA is intent on rejecting an RTO-organized market mechanism for AIC that the IPA has already accepted for ComEd, then the IPA should provide valid reasons for the apparent inconsistency.

In its Reply to Responses, Staff states its belief that AIC misinterprets Staff's objections to the Plan. Staff was not making a recommendation to rely on the MISO market for all capacity needs beginning with the 2013-2014 Plan year. Rather, Staff was objecting to the Plan's lack of analysis and a rationale for not relying on such a market for AIC vis-à-vis MISO, when the IPA has taken the complete opposite approach with ComEd vis-à-vis PJM. Staff states that AIC, on the other hand, provides just such an analysis and rationale, which Staff believes are satisfactory for now, pending further developments at MISO.

Staff says AIC notes that the PJM capacity market is based on a three year forward process, whereas the proposed capacity market at MISO is based on a one year forward process. AIC further explains the importance of this distinction. Staff says this first part of AIC's analysis and the accompanying rationale are satisfactory for now, but Staff claims neither the IPA nor AIC provide any convincing proof that the three-year versus one-year distinction between the PJM and MISO capacity markets will be sustained when a final determination is ultimately made.

Staff notes that AIC also argues that procuring 100% of the capacity for the 2013-2014 plan year through an untested MISO process could carry with it certain risks to customers because the new auction process could result in prices well above those seen in recent IPA solicitations and via the MISO monthly auction process. Staff agrees that this "new and untested" argument has appeal, but again, only for so long. Staff believes that eventually, the new auction process will be tested and will cease to be new.

As for Staff's proposal to limit this year's procurement to the 2012-2013 Plan year, AIC responds that allowing the IPA to solicit capacity for the 2013-2014 and 2014-2015 Plan years carries with it an option, but not an obligation to procure. Staff states that this is true, but only to the limited extent that the price benchmark and the Commission's final approval process permit the rejection of bids. Staff believes that taken together, AIC's arguments reinforce a wait-and-see approach toward capacity procurement for the 2013-2014 and 2014-2015 Plan years.

2. AIC's Position

AIC agrees with Staff that the MISO capacity market beyond the proximate 2012-2013 Plan year is in flux. AIC says at the least there is no certainty regarding the fledgling MISO capacity market. MISO has proposed to FERC that beginning with the

2013-2014 Plan year, it will move from a monthly capacity construct to a yearly capacity construct with zonal differences. AIC indicates this filing has caused considerable interest among parties and AIC estimates that approximately 90 entities have intervened. According to AIC, it is uncertain if the MISO proposal will be approved by FERC, approved as modified, or rejected outright. Nor is it certain when any resulting changes will be implemented by MISO. AIC claims that what is clear is that AIC load will have some form of MISO capacity requirement going forward. AIC says it also knows that the monthly construct will be applicable for the 2012-2013 Plan year. AIC therefore agrees with the IPA proposal to procure any remaining 2012-2013 quantities as described in the Plan.

In AIC's view, what remains unclear is the best course of action for customers beginning in the 2013-2014 Plan year and beyond. While AIC understands the basis for the Staff recommendation to rely on the MISO market for all capacity needs beginning with the 2013-2014 Plan year, AIC believes two issues should be brought forth before a decision is made.

First, AIC indicates that the PJM capacity market is based on a three year forward process, whereas the proposed capacity market at MISO is based on a one year forward process. AIC believes this is a key difference between the two RTOs because any bilateral solicitations by the IPA in advance of the PJM auction would require a solicitation in excess of three years in advance of the planning year. However, AIC says an IPA solicitation in advance of the MISO auction could be accomplished on a timeline consistent with the IPA's past practice (i.e., ladder for years 1, 2 and 3). For example, AIC states that that in previous procurement plans, the IPA has purchased capacity for AIC at 100% of forecast for year 1, 70% for year 2 and 35% for year 3. For ComEd, the PJM capacity market purchases 100% of year 3 capacity and on a rolling three year basis, the result to ComEd is that 100% of years 1, 2, and 3 are purchased. The Staff proposal to rely entirely on the proposed MISO market for AIC beginning with the 2013-2014 Plan year would result in 100% purchased for year 1, but 0% purchased for years 2 and 3. AIC notes this represents a significant departure from past procurement plans pertaining to AIC. AIC claims it would also create a dramatic difference in hedging strategies when comparing AIC to ComEd.

Second, AIC states that procuring 100% of the capacity for the 2013-2014 Plan year through an untested MISO process could carry with it certain risks to customers because the new auction process could result in prices well above those seen in recent IPA solicitations and via the MISO monthly auction process. AIC also suggests that allowing the IPA to solicit capacity for the 2013-2014 and 2014-2015 Plan years carries with it an option, but not an obligation to procure. AIC believes this option may help to mitigate customer risk because the IPA, Staff, Procurement Administrator, and Procurement Monitor would set price benchmarks associated with the IPA capacity solicitation. AIC says that using the IPA proposal as a guide, this benchmarking process will result in no more than 50% of the capacity required to be procured by the IPA for the 2013-2014 Plan year and 35% of the requirement for the 2014-2015 plan year. AIC adds that it could also result in less capacity being procured by the IPA depending on supplier bids relative to the price benchmarks. Given a scenario where no suppliers meet the price benchmarks associated with the solicitation, AIC says 0% would be procured by the IPA and 100% would be procured via the MISO auction. AIC asserts that a bilateral solicitation creates optionality that the IPA, Staff, Procurement Administrator, and Procurement Monitor can manage on behalf of customers through the price benchmark process.

AIC indicates that it understands the difficulty associated with determining the best course of action regarding capacity solicitations beginning with the 2013-2014 Plan year. AIC believes both the IPA and Staff have put forth proposals that have merit. However, given the discussion set forth previously, AIC believes the IPA proposal represents the better of the two options. That being said, if the Commission disagrees with AIC and determines that the IPA should solicit capacity for the 2012-2013 Plan year only and not for the 2013-2014 and 2014-2015 Plan years, AIC requests that this issue be reviewed again in the following Plan years as opposed to making a precedent-setting decision while the MISO proposal as filed at FERC remains under scrutiny.

In its Reply to Responses, AIC notes that the IPA agrees with the Staff position that the Plan should be modified to procure capacity for AIC only for the June 2012 through June 2013 planning year as opposed to the original Plan which would solicit 50% of the projected capacity for 2013-2014 and 35% of the capacity for 2014-2015. The IPA therefore recommends modifications to the Plan to eliminate solicitations for the 2013-2014 and 2014-2015 planning years.

AIC maintains that that the original Plan arguably contained a better proposal. AIC states that this decision is a difficult one, but AIC points to key differences between the PJM capacity market and that pondered by MISO, namely a three-year forward market versus a one-year forward market. AIC says the result is that adopting the strategy in the revised IPA proposal will result in a dramatically different hedging strategy between AIC and ComEd. AIC states that while it is true that that past Plans have had different hedging strategies for AIC and ComEd, this difference becomes more dramatic with the revised IPA proposal. AIC believes returning to original IPA proposal would reduce this difference and maintain consistency with prior Plans.

According to AIC, pursuing a solicitation as pondered by the IPA in its original Plan does not obligate the IPA to make purchases on behalf of AIC. AIC claims that is because the benchmarking process lies with the IPA in conjunction with the Procurement Administrator, Staff and Procurement Monitor. AIC says any bids above the benchmark would be rejected in favor of purchases via MISO.

AIC notes that MISO has committed to keep its monthly capacity construct in place for 2012-2013. AIC states that bilateral purchases, as proposed in the Plan should be priced as $/MW-Month, which is consistent with prior years. AIC claims the MISO proposal pending at FERC suggests a transition to a yearly capacity construct with zonal differences starting in 2013-2014, though it remains unclear if such a proposal will be approved and implemented by 2013-2014. AIC suggests bilateral purchases could be made by the IPA for 2013-2014 and 2014-2015 pursuant to its original Plan, with pricing as $/MW-Year in anticipation of the MISO transition to a yearly construct. However, in the event the MISO proposal at FERC is delayed or rejected, AIC says the contracts associated with any 2013-2014 and 2014-2015 bilateral purchases could include language such that the quantities and price are converted to $/MW-Month so as to comply with the current monthly capacity construct.

According to AIC, uncertainty surrounding when MISO will commence its yearly capacity market can easily be addressed by the Procurement Administrator in the drafting of the contracts associated with an IPA bilateral solicitation for 2013-2014 and 2014-2015. AIC states that if such a solicitation results in capacity suppliers applying a risk premium to their bids, the benchmarking process will protect customers should that premium be priced at unacceptable levels.

AIC says it understands the difficulty associated with determining the best course of action regarding capacity solicitations beginning with the 2013-2014 Plan year. Given the detailed discussion in its Response, AIC believes the original IPA proposal to purchase a portion of capacity for 2013-2014 and 2014-2015 represents the better of the two options. If the Commission disagrees with AIC and determines that the IPA should solicit capacity for the 2012-2013 Plan year only and not for the 2013-2014 and 2014-2015 Plan years, AIC requests this issue be reviewed again in the future Plan years.

3. IPA's Position

The IPA agrees that the Plan should be modified to procure capacity for AIC for the June 2012 through May 2013 plan year since that is how MISO's existing tariff is set up. Therefore, the IPA suggests making the following modifications to the Plan:

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

In its Reply to Responses, the IPA indicates that AIC recommends a compromise between the IPA's original Plan (to procure capacity in a 3-year laddered approach), and Staff's recommendation (a single-year procurement event). The IPA says AIC recommends that the IPA be granted authority to: 1) set benchmarks for a 3-year laddered approach, 2) solicit bids for three years consistent with the IPA's Plan, but 3) only procure capacity in the 2012-2013 and 2013-2014 years if the bids are within the benchmarks. The IPA states that AIC's approach will allow the Commission to ensure that capacity procured in subsequent plan years are within the Commission's benchmarks, but still permit the IPA to reject bids where the future uncertainties of the MISO market are causing current prices to exceed the benchmark.

The IPA believes that AIC's compromise proposal is reasonable, and requests that the Commission accept AIC's recommendation.

4. Commission Conclusion

In its Objections to the Plan, Staff raised concerns about the IPA's plan to secure capacity for the 2013-2014 and 2014-2015 planning years. Both AIC and the IPA responded to Staff's proposal and recommended modification to Staff's recommendation. Staff believes that AIC misinterpreted its recommendation. In its Reply to Responses, the IPA recommends adopting AIC's recommendation. Additionally, it appears that while Staff sees limited potential in adopting AIC's recommendation, Staff believes its proposal to only solicit capacity for 2012-2013 is preferable.

The IPA views AIC's proposal as a compromise between the IPA's original Plan (to procure capacity in a 3-year laddered approach), and Staff's recommendation (a single-year procurement event). The IPA says AIC recommends that the IPA be granted authority to: 1) set benchmarks for a 3-year laddered approach, 2) solicit bids for three years consistent with the IPA's Plan, but 3) only procure capacity in the 2013-2014 and 2014-2015 years if the bids are within the benchmarks. The IPA states that AIC's approach will allow the Commission to ensure that capacity procured in subsequent plan years are within the Commission's benchmarks, but still permit the IPA to reject bids where the future uncertainties of the MISO market are causing current prices to exceed the benchmark.

The Commission again believes that Staff has raised an important issue. It appears to the Commission, however, that AIC's proposal is superior to Staff's. Under both proposals, a solicitation for capacity would take place for 2012-2013. Under AIC's proposal, a solicitation for capacity would occur for 2013-2014 and 2014-2015 as well. Also under AIC's proposal, capacity for 2013-2014 and 2014-2015 would only be procured if bids are within the benchmarks. In the Commission's view, AIC's proposal represents an opportunity, with no obligation, compared to Staff's proposal. The Commission finds AIC's proposal for capacity solicitation should be included in the 2012 Plan.

M. Three-Year Laddered Approach to Procurement

1. ICEA's Position

According to ICEA, the current procurement approach for eligible customers creates a barrier to achieving full, sustainable competition by procuring too infrequently and relying too heavily on longer-term contracts that can create a “boom or bust” cycle for ARES and send incorrect price signals to consumers. ICEA asserts that the IPA’s three-year laddered approach to procuring electricity relies on “point-in-time” pricing, which essentially guarantees that the default rate fails to reflect current wholesale market prices over the course of the procurement period.

ICEA claims that at any given time, the default pricing may be significantly above current wholesale prices, which seemingly provides an opportunity for ARES to effectively compete by “beating” the default rate. ICEA believes that model is unsustainable because at any other given point in time the default rate could be significantly lower than current wholesale prices, making it difficult for ARES to properly manage risk and encouraging consumers to return to utility service. ICEA asserts that default pricing that is continuously reflective of current wholesale prices provides the best environment for sustainable, robust retail competition and correct market price signals for consumers.

ICEA contends that continued progress towards a robust competitive electric market best helps consumers balance price risk and budget certainty. According to ICEA, robust retail competition puts downward pressure on prices, offers a variety of product options for end-use customers, increases conservation incentives, and enhances customer service. ICEA says recent developments indicate that significant reductions to the barriers to retail competition in residential markets are on the near-term horizon. ICEA also says that, in order to protect consumers and encourage residential retail competition, the IPA should procure power more frequently.

ICEA argues that given the recent positive developments in residential shopping and the IPA’s repeated acknowledgement that more frequent procurements are better for consumers, there is simply no reason to continue with the current laddered procurement approach. In ICEA's view, now is the time to increase the frequency of the procurements and shorten the contract lengths to allow the default price to be more reflective of current market prices and enhance competition.

2. RESA's Position

RESA complains that the 2012 Plan does not even mention, let alone recommend, multiple procurement events as a means to mitigate the risks inherent in a one-time procurement event approach. RESA believes that this is a serious shortcoming of the 2012 Plan which should be remedied by the Commission in this proceeding.

RESA suggests there are many methods that can be used to implement a multiple procurement structure, including having the current once-a-year approach broken down into four phases, with potential bidders electing at the first phase which of the four procurements in which to take part. RESA says this would prevent the IPA from having to conduct the same participant application and screening process four times (thus needlessly adding to the IPA's administrative burdens. RESA suggests other additional steps can be taken to reduce the additional burden caused by multiple procurement events, and those too should be considered.

RESA recognizes that in addition to more frequent procurement events, there are other mechanisms that can be considered to make current default service more market reflective. RESA says, for example, the current weighting of the three-year blended contracts could be changed so that heavier weight is placed on the current energy year; or, rather than using three-year blended averages, shorter contract terms, such as 3, 6, and 12 month blended terms could be utilized.

RESA believes that 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 says 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. According to RESA, 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 argues that the failure of long-term procurement contracts to reflect current wholesale market prices creates inefficiencies in either direction. RESA says that in the event that the company's procurement costs are higher than those available in the wholesale market, then customers are harmed by having to pay higher than market prices. In the event that wholesale market prices rise above the locked in utility costs, RESA says customers will receive incorrect price signals that distort the market and give rise to the following unintended harmful consequences: 1) a belief that energy is less expensive than reality, leading to potential over-consumption; 2) discouraging energy efficiency investment by under-valuing avoided costs; and, 3) the risk of rate shock as those contracts end. RESA claims that in all of these instances, customers will be harmed.

RESA contends that the use of mechanisms which would result in market reflective pricing would enable the procurement of shorter-term contracts which could be procured closer in time to actual delivery of the supply. RESA also says the use of shorter term contracts procured closer in time to the date of delivery will enable customers to see a default price that better reflects prevailing market prices and will minimize long-term contract hedging premiums that are associated with longer term contracts procured far in advance of delivery. RESA insists that better price signals will spur more thoughtful efficiency investments, wise energy usage, and spur development of the competitive market. RESA says better accuracy reduces customer costs over the long-term. In RESA's view, 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 its Response to Objections, as well as its Reply to Responses, RESA, essentially restates its position on this issue. RESA suggests the AG misstates RESA's position to be that the three-year laddered approach should be replaced with a simple annual procurement. RESA says it is not advocating an annual procurement. RESA advocates market reflective pricing, which could include multiple procurement events. RESA suggests that in addition to more frequent procurement events, there are other mechanisms that can be considered to make current default service more market reflective. RESA says the current weighting of the three-year blended contracts could be changed so that heavier weight is placed on the current energy year; or, rather than using three-year blended averages, shorter contract terms, such as 3, 6, and 12 month blended terms could be utilized. RESA suggests these mechanisms, and more, can be examined in the workshops advocated by RESA and, if appropriate, incorporated into the IPA's 2013 procurement Plan.

RESA states that the AG claims that RESA and ICEA are suggesting that customers should be disproportionately exposed to short-term wholesale prices. RESA says the use of the term "expose" implies that Illinois ratepayers only have default service as an option. RESA claims that is not the case, RESA believes there are opportunities for customers to shop for customized products and services from retail electricity suppliers.

According to RESA, the AG implies that RESA and ICEA's objection to the three-year laddered approach is because it is inconsistent with their business plans. RESA does not object to the three-year laddered approach because it is inconsistent with the business plans of its members. RESA objects to the three-year laddered approach because it believes it is an inferior method of procurement.

RESA says the AG faults RESA and ICEA for not demonstrating that the three-year laddered approach harms consumers or contradicts the IPA's statutory duty. While RESA is unable, after the fact, to demonstrate that the three-year laddered approach has resulted in increased prices to consumers because the data does not exist to make such a demonstration, RESA claims it has shown that the three-year laddered approach is not in the best interest of customers. With respect to the IPA's statutory duty, RESA claims the IPA itself acknowledged in its first procurement plan that it should move toward market reflective pricing.

ComEd states that the IPA has performed a risk analysis demonstrating that the three-year laddered approach best satisfies the requirement of providing energy to customers at the lowest cost over time taking into account any benefits of price stability.

RESA contends that risk analysis does not demonstrate that the three-year laddered approach is superior to a market reflective approach, particularly from a cost standpoint.

ComEd claims that more frequent procurement events and shorter contract durations will move toward spot market pricing, which, according to ComEd, conflicts with the PUA's directive to seek price stability, as well as low cost. RESA's response is that its proposal for market reflective pricing is a long way from advocating that spot market pricing be utilized in the IPA's procurement Plan. Although it is not advocating it here, RESA notes that in other jurisdictions, spot market pricing is used as a small component of a blended default service rate offered to small customers.

According to RESA, ComEd suggests that RESA's and ICEA's proposals are based on a claim that they cannot compete for customers and that this is refuted by the fact that ComEd's eligible retail customer base is "shrinking rapidly" due to customers switching to ARES. RESA responds that it has never claimed that the three-year laddered approach prevents its members from competing for customers. RESA says it advocates in favor of market reflective pricing to the benefit of consumers.

RESA says the IPA also opposes RESA's and ICEA's proposals to move away from its three-year laddered approach. According to the IPA, it is unclear that the costs of additional procurements would be outweighed by the benefits of holding these events. RESA claims that because the IPA has not investigated multiple procurement events, despite indicating in its initial procurement Plan, that it would do so, it is equally true that it is unclear that the benefits of additional procurements would be outweighed by the cost of holding these events.

RESA is requesting is that the Commission order workshops to investigate the use of market reflective pricing. During those workshops, RESA says the benefits and costs of proposals to implement such pricing can be examined.

Staff disagrees with the proposals of RESA and ICEA for market reflective pricing, claiming that these proposals would be too costly to implement with the IPA procurement process and would unduly increase risk to ratepayers without a reasonable expectation of savings. RESA is not aware of any evidence of what the cost of additional procurement events would be, let alone that they would be too costly to implement. RESA also says it is not aware of any evidence that a move toward market reflective pricing would either increase risk to ratepayers, or describe what type of risk that might be. RESA claims that the IPA's first procurement Plan correctly identifies the increased price risk consumers face with a single procurement event – a risk that can be avoided by holding more frequent procurements.

Staff indicated that, if the Commission agreed with RESA and ICEA that greater market reflective pricing would be beneficial, Staff would not oppose a modest reduction in the 2012 Plan's hedge ratios. Staff offered, for illustrative purposes, a table showing an alternative plan that would reflect such modest reductions. RESA says this is a plan that could be reviewed during the workshops requested by RESA.

3. IPA's Position

The IPA acknowledges, as it has in past procurements, that there can be market conditions where multiple procurement events in a planning year could result in increased competition. The IPA believes that ultimately, real-time pricing (where prices to eligible retail customers are set on an hourly basis) could reflect a more competitive market. That said, the IPA observes that its sole purpose is not to increase competition, but to "ensure adequate, reliable, affordable, efficient, and environmentally sustainable electric service at the lowest total cost over time . . . ." Additionally, the IPA believes it is unclear that the costs of the additional procurements would be outweighed by the benefits of holding those events. Therefore, taking into consideration all factors that go into determining how to best structure the 2012 procurement event, including administrative burden and price stability, among others, it is the IPA's judgment that the Plan is best served through a single annual procurement at this time.

4. ComEd's Position

ComEd recommends that the Commission reject RESA's and ICEA's recommendation that the Commission and the IPA turn away from the combination of low prices and price stability that the 3-year laddered procurement approach has produced to a world of more frequent procurement events and shorter-term contracts. ComEd states that the IPA has performed a risk analysis demonstrating that its proposed three-year laddered procurement process best satisfies the requirement of providing energy to customers at the lowest total cost over time taking into account any benefits of price stability. ComEd asserts that RESA and ICEA have provided no contrary analysis and have demonstrated no flaw in the IPA's analysis. ComEd believes that failing alone should lead to their objection being rejected, because the Commission must evaluate it based on evidence.

ComEd argues that moving toward more frequent procurement events, and shorter and shorter contract durations, will move the pricing of energy for ComEd's eligible retail customers to something close to spot market pricing. ComEd believes this is in conflict with the PUA's directive to seek price stability for customers as well as low cost.

ComEd says RESA and ICEA also imply that providing a relatively stable, three year average price for eligible retail customers somehow unfairly restricts ARES ability to compete for customers. In ComEd's view, this argument makes no sense. ComEd contends that nothing prevents an ARES from engaging in its own long-term procurement for a portion of its load (or to use financial tools to achieve an equivalent result) if it actually believed that the appeal of price stability for customers was too strong to complete with. ComEd contends the implied consumer preference for stability undercuts RESA's and ICEA's request to make retail energy prices less stable. According to ComEd, any claim that they cannot compete is refuted by the facts. ComEd's claims its eligible retail customer base is shrinking rapidly due to customer switching. ComEd says ARES not only can compete – but every day are competing very successfully in ComEd's territory. ComEd insists that the claim that the current procurement program retards retail competition clearly has no merit.

In its Reply to Responses, ComEd says RESA asks the Commission to direct the IPA to hold workshops on replacing the proven yearly laddered approach proposed by the IPA and approved by the Commission in every order since the genesis of the IPA. ComEd maintains that the laddered approach has promoted supplier competition and provided price stability for customers. ComEd claims it is also supported by detailed analysis in the IPA Plan. ComEd also claims there is no support from any other interested party in this proceeding to move away from it. ComEd notes that the AG specifically rejects it and Staff opposes making such a dramatic change with no evidence of how it would benefit customers. Given the striking absence of both evidence and interest, it would not be productive to hold workshops dedicated to moving away from the laddered approach and ComEd believes the Commission should decline to mandate them.

5. AG's Position

The AG states that some representatives of the competitive energy sector argue that the three-year ladder strategy, which includes purchases for future years in each annual procurement, is inconsistent with the "competitive market" and should be replaced with a simple annual procurement. The AG believes this objection takes an unreasonably restrictive view of the "market" by suggesting that customers should be disproportionately exposed to short-term wholesale prices, and should be rejected.

The AG contends that in purchasing electricity from suppliers, end-users are not limited to spot market prices, single year contracts, real time prices, or any other combination of terms. Similarly, the AG says suppliers are free to offer consumers services and prices based on various terms, reflecting a combination of peak, off-peak, long-term, short-term, or other factors. According to the AG, the IPA is charged with obtaining the lowest total cost over time, taking into account any benefits of price stability. The AG argues that while suggesting that the three-year ladder was not consistent with their business plans, the parties objecting to the three-year ladder strategy did not demonstrate that the 2012 Plan would harm consumers or contradict the IPA's basic statutory duty. The AG recommends that the Commission reject the Objections to the three-year ladder and confirm that aspect of the 2012 Plan.

6. Staff's Position

Staff states that in theory, it does not necessarily oppose the concept of introducing more frequent procurement events or reducing how far into the future energy price hedges are established. However, Staff is reluctant to support the proposals of ICEA and RESA to hold more than one energy procurement event per year because there are significant costs to holding more frequent procurement events (that are compliant with the PUA and the IPA Act). Staff is also reluctant to support a dramatic alteration of the IPA's current strategy of partially hedging up to three years into the future, without some convincing evidence that the replacement strategy is expected to decrease total costs or that eligible retail customers are unconcerned about price volatility. However, Staff would not be opposed to modest reductions in the Plan's hedge ratios, if the Commission were to agree with ICEA and RESA that more market reflective pricing would be of benefit. For illustrative purposes, Staff would consider the "Alternative Plan" in the following table to reflect modest changes.

	Target Hedge Ratios by the Start of Each Plan Year	
Plan Year	Per IPA Plan	Alternative plan
PY 2012-2013	100%	90%
PY 2013-2014	70%	50%
PY 2014-2015	35%	25%
	Annual Additions to Hedge Ratios following Transition	
Plan Year	Per IPA Plan	Alternative plan
Immediate PY	30%	40%
Immediate PY + 1	35%	25%
Immediate PY + 2	35%	25%

7. AIC's Position

In its Reply to Responses, AIC notes that Staff puts forth a conditional alternative to the three-year hedging ratio used by the IPA in this and past Plans given a scenario where the Commission agrees with ICEA and RESA that more market reflective pricing would be of benefit.

AIC states that the hedging strategy of 100% in year 1, 70% in year 2 and 35% in year 3 has been used successfully in past Plans and resulted from considerable analysis by the IPA. AIC believes any deviation from the existing strategy should be backed by analysis suggesting it is the more beneficial alternative. AIC says since no analysis exists in this Plan, AIC suggests the Staff alternative should be tabled until such time as the IPA and its consultants can evaluate this proposal and include the results in future Plans.

8. Commission Conclusion

ICEA and RESA want the Commission and the IPA to reconsider the three-year laddered approach to procurement and develop an alternative that better reflects market prices. At a minimum, RESA wants the Commission to direct the IPA to undertake workshops to reconsider this issue. The AG, the IPA, AIC, and ComEd object to reconsidering the three-year laddered approach. Staff states that it does not necessary oppose changing the procurement approach and provides an illustrative alternative to procurement.

It appears to the Commission that there may some miscommunication or misunderstanding among various parties regarding this issue. While the Commission does not wish to revisit history, the Commission believes it is important to recall that the IPA Act and the IPA itself arguably grew out of the Illinois Auction processes approved in Docket Nos. 05-0159 through 05-0162. The existing procurement process has evolved since then.

It is not clear that in this proceeding there is any basis for deviating from the three-year laddered approach adopted in the previous procurement proceedings. While ICEA and RESA seem to suggest a change is appropriate and Staff suggests it is theoretically possible, no party seems to go as to propose an alternative in this proceeding. For purposes of the 2012 Plan, the Commission concludes that the IPA's three-year laddered approach is reasonable and should be approved.

As for RESA's request regarding workshops, the Commission believes that requiring workshops is not necessary at this point in time. All parties have significant obligations and limited resources. If RESA wishes to present a quantitative analysis supporting its position that an alternative to the three-year laddered approach is superior, the Commission might be willing to reconsider the issue in a future proceeding.

N. Procurement Schedule

1. Constellation's Position

According to Constellation, many of the 2011 procurements took place several weeks later than those same procurements had occurred in the past and were the latest in history since the creation of the IPA in 2007. Constellation believes that timing contributed to approved utility tariffs regarding new rates being made available by ComEd a mere one day before those rates went into effect. Constellation states that upon completion of the procurements, utilities must run the numbers through their respective rate translation mechanisms to arrive at a particular price per kWh for bundled service customers. Constellation believes that holding procurements so close in time to June 1st necessarily backs up the timeline of when those new rates can effectively be published.

In Constellation's view, delays in release of the tariffs and charges cause substantial confusion and competitive harm in the retail market. Constellation says last year was the first year in which there was meaningful opportunity for switching to ARES in the residential market. Constellation says there are currently 13 ARES licensed to serve residential customers in ComEd's service territory, and 8 ARES licensed to serve residential customers in AIC's service territory. Constellation asserts that ARES may have found it difficult to go to market with offers that were attractive to customers, given that changes to utility bundled rates were imminent, but without knowledge as to those revised rates and tariffs.

Constellation notes that the Plan calls for procurement events to be held earlier than occurred for the 2011 Plan. Constellation believes that to the extent that procurements are to occur in the same year as the start of the new June-May cycle, as the Plan currently contemplates, the procurement events should be held in late February or early March. Constellation asserts that holding all procurement events during that time will have no material negative impact on the procurements themselves, and the timing will benefit suppliers and, ultimately, retail customers. Constellation believes the Commission Order ultimately approving the IPA Plan should establish a schedule that permits calculation of new rates sufficiently in advance of their effective date, and require that utilities file and make available approved tariffs and charges not less than two weeks before new rates go into effect.

2. RESA's Position

Like Constellation, RESA notes that many of the 2011 procurements took place several weeks later than those same procurements in the past. RESA says they were the latest since the creation of the IPA in 2007. RESA states that timing contributed to approved utility tariffs regarding new rates being made available by ComEd only one day before those rates went into effect.

RESA asserts that delays in the release of utility tariffs and charges cause substantial confusion and competitive harm in the retail market. To the extent that procurements are to occur in the same year as the start of the new June-May cycle, RESA suggests the procurement events should be held in late February or early March. This will benefit suppliers and their customers. RESA recommends that future Commission orders approving the IPA Plans should establish schedules that permit calculation of new rates sufficiently in advance of their effective dates and require that utilities file and make available approved tariffs and charges no less than two weeks before the new rates would go into effect.

In its Response to Objections, RESA maintains its position.

3. IPA's Position

The IPA acknowledges the benefits of standardizing contracts and will continue to work with the utilities, wholesalers, Procurement Administrators, and Staff towards that goal. Ultimately, the IPA believes that contract issues such as this should be handled outside of the Plan.

In its Reply to Responses, the IPA acknowledges the benefits of accelerating the procurement schedule, and notes that it will endeavor to accommodate an accelerated schedule. However, the IPA insists it must also abide by all statutory restrictions and requirements that may not always result in an advanced schedule. For example, Section 1-75(a) provides a lengthy RFP process that the IPA must go through to select a Procurement Administrator, which includes the requirement that affected utilities and other interested parties be given an opportunity to object to a list of proposed qualified experts. The IPA states that thereafter, the Procurement Administrator is required to design the final procurement process, develop benchmarks used to evaluate the bids, manage the bidder pre-qualification and registration process, and obtain the utilities' agreement to the final form of the contracts. The IPA urges the Commission not to set deadlines that micromanage this process.

The IPA plans to continue to work with Staff, Procurement Administrators and Procurement Monitor to come up with the best possible schedule, but the IPA believes the Commission should not direct that the procurement event take place on or before any specific date.

4. Commission Conclusion

Constellation and RESA complain that that many of the 2011 procurements took place several weeks later than those same procurements in the past. Both request that the Commission Order establish a schedule that permits calculation of new rates sufficiently in advance of their effective date, and require that utilities file and make available approved tariffs and charges not less than two weeks before new rates go into effect.

The IPA acknowledges the benefits of accelerating the procurement schedule, and notes that it will endeavor to accommodate an accelerated schedule; however, the IPA insists it must also abide by all statutory restrictions and requirements that may not always result in an advanced schedule. The IPA urges the Commission not to set deadlines that micromanage this process.

The Commission is sympathetic to the issue raised by Constellation and RESA. The Commission, however, is mindful of the many responsibilities of the IPA and the difficulties it faces in fulfilling its legislative mandates. The Commission concludes that for purposes of the 2012 Plan, it will not adopt the recommendations of Constellation and RESA. The Commission cautions the IPA that in the future, if it is not willing or able to carry out its obligations in a timely manner, the Commission will, reluctantly, take steps to intervene, even if it requires setting deadlines which the IPA may view as micromanaging the process.

O. Regulatory Uncertainty

According to Constellation, the time period between the submission of bids and the timing that potentially winning suppliers are notified should be shortened, to the greatest extent possible. Constellation says both the IPA and the Commission are to be commended for reducing the time period between submission of bids and contract execution. Constellation states that the most recent IPA Plan 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 during this most recent procurement cycle. Constellation believes further improvements can be made in shortening the time period for “informal” notification to potentially winning bidders.

Constellation asserts that 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. Constellation says that while bids are held open during the review process, bidders retain the risk that market prices will change suddenly or unexpectedly. In Constellation's view, this risk is particularly important in procurement events involving block energy products, given the volatility in today's market. Constellation claims potential suppliers have to incorporate such risks in their bids to account for this time lag and these risks will necessarily translate into bid prices.

Constellation insists 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. Given that the block energy products are standard wholesale energy products, Constellation asserts the review of these bids should be relatively straightforward, and should not require negotiation or additional review time. Constellation 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. Constellation says 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.

Constellation believes that ideally, bids would be submitted in the morning with results as to likely winning bidders provided that same day. Constellation repeats that the review of bids for standard block energy products should be relatively straightforward, and should not require additional time. Constellation says at most, next day notification of likely winning bidders should be provided. Constellation also says scheduling procurements for earlier in the week, preferably Monday or Tuesday, will best ensure that bidders will not need to hold prices open unnecessarily over a weekend. Constellation thinks this is of particular importance for the energy procurement, in which there is the greatest price volatility.

Constellation recommends that to the greatest extent possible, the time period between the submission of bids and the timing that potentially winning suppliers are notified should be shortened. No party responded to Constellation's suggestion and the Commission directs the IPA and Staff, to the extent possible, to implement Constellation's recommendation in the 2012 procurement process.

P. Application, Credit, and Contracting Process

Constellation recognizes and appreciates the strides that have been made through previous procurement cycles for improvements in standardizing products and contracts, and recommends that the IPA and the Commission take this opportunity to make further refinements in this year's Plan.

In Constellation's view, the process could benefit from streamlining and standardizing contracts. Constellation says the three products are currently procured under three distinct contracts, one for energy, one for capacity, and a third for RECs. Constellation adds that new “master 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. Constellation believes entering into new contracts for each product each year is inefficient. Constellation asserts that the master agreement should be a true master agreement; there should only be one agreement, containing separate confirmations for each product. Constellation suggests that each year, additional confirmations could be entered into pursuant to the existing master agreement. Constellation suggests the master agreement could and should be used for procurements in multiple years, updating as necessary through the amendments during the annual process, rather than entering into new contracts with slightly different contract terms each year. Constellation believes using a single master agreement to procure all products across multiple years would significantly reduce the administrative burden on bidders, the Procurement Administrator, the Procurement Monitor, and the Commission. Constellation believes reducing the administrative burden on bidders could potentially lead to an increase in the number of bidders and a decrease in the cost of the products procured.

Constellation recommends streamlining and standardizing contracts to the extent possible. No party responded to Constellation's suggestion and the Commission directs the IPA and Staff, to the extent possible, to implement Constellation's recommendation in the 2012 procurement process.

Q. Bidder Signatures

Constellation believes that given the number of forms to be signed at different times throughout the procurement process, the bidding rules should allow for some flexibility. Constellation says that currently, ComEd requires that the same officer of a bidder sign each of the following forms: Part 1 Form, Part 2 Form, Master Agreement, Confirmation, and Supplier Fee Binding Agreement. Constellation claims that strict adherence to such a policy fails to recognize the fact that the same person may not be physically in the office each day, due to business travel, personal vacation, or unforeseen events. Constellation says AIC's rules take these exigencies into account, permitting a secondary signatory if the original signatory is unavailable for whatever reason; Constellation believes ComEd should be required to do the same.

Constellation recommends that ComEd be required to adopt AIC rules permitting a secondary signatory if the original signatory is unavailable for whatever reason. As no party, including specifically ComEd, responded to Constellation, the Commission finds that its recommendation should be approved. ComEd is hereby directed to implement Constellation's recommendation.

R. Procurement of Full Requirements Products

1. Constellation's Position

In order to procure supply required to meet the needs of eligible retail customers, as defined within the PUA, Constellation believes the Plan should be modified to use full requirements, load following ("full requirements") products. Constellation says the IPA is given discretion to procure products individually, or in combination. Constellation suggests the IPA should take into consideration the fact that customers bear greater risk with separate block products, because the shape and quantity of the load is not known, and should modify the Plan accordingly by procuring full requirements contracts.

According to Constellation, the benefits offered by a full requirements approach have never been greater than this upcoming procurement cycle due to the likelihood that the number of utilities bundled customers and underlying load will be reduced, potentially dramatically, during that time. Constellation 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 a Commission "Price to Compare" to research retail price offers, development of referral programs, and local communities moving forward with municipal aggregation plans, all support the proposition that the policy supporting competitive electricity markets will continue and strengthen, and that a portion of the eligible retail consumers currently served through the IPA portfolio will migrate towards ARES options. Constellation says the IPA acknowledges recent developments indicate that significant reductions to the barriers to retail competition in residential markets are on the near-term horizon. Constellation also asserts that as a function of the unknown pace of migration of eligible customers to ARES, the portfolio is exposed to load uncertainty risk.

In Constellation's view, a full requirements approach will best meet the requirements of Illinois law. Constellation believes 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. Constellation contends that a full requirements approach will limit risks to customers by shifting them 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 product offerings of ARES.

According to Constellation, as risks and costs to ComEd and AIC appropriately are passed on to their customers, it follows that the full requirements approach limits the risk to utilities customers by shifting them largely to full requirements product suppliers. Constellation asserts that full requirements products provide consumers with insurance for the duration of the contract by shifting risk to wholesale suppliers. Constellation believes 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 Constellation's view, a diverse pool of wholesale full requirements product suppliers provides the most cost-effective method of management for eligible retail customers. Constellation claims that under full requirements product procurements, utilities provide to potential bidders prior to procurements, and to winning bidders on an ongoing basis afterwards, all of the load data for their individual customer classes. Constellation says wholesale suppliers are specialists in the area of portfolio management, and have greater resources, expertise, and ability to appropriately utilize this data to manage portfolios of supply at the least possible cost, by allocating the costs for their operations over much larger load obligations throughout the country. Constellation also says such suppliers are able to draw from their substantial experience throughout PJM, MISO, and in 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. Constellation asserts 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. Constellation claims 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.

Constellation claims to have hundreds of employees involved in the process of providing full requirements service to utilities and customers around the country, serving tens of thousands of megawatts of various types of full requirements load from coast to coast. Constellation says it employs a team of seasoned portfolio managers for large regional portfolios that serve Constellation's customers' full requirements loads. Constellation says it must ensure that any transaction that goes into Constellation's 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. Constellation also says 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 Constellation's portfolio managers may face. In addition, Constellation 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. Constellation 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 Constellation's supply portfolio. Moreover, Constellation says 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. Constellation adds that similar resources focus on fuel oil, natural gas, coal, currency, emissions and renewable energy markets. According to Constellation, full-time meteorologists on Constellation's team continually monitor and predict the weather, so that Constellation's team can plan for weather effects on load requirements, and adjust supply accordingly. Constellation says the task of meeting full requirements load supply additionally requires controllers, schedulers, and dispatchers. Constellation says 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.

In Constellation's view, a wholesale supplier's greater expertise in these activities represents a valuable asset in evaluating and engaging in transactions for not only for complex hedges and other energy products, but for more common products in a portfolio such as block and spot market purchases. Constellation says increased levels of expertise and the ability to take on and manage a large portfolio's risks and responsibilities enable a wholesale supplier such as Constellation to provide significant competitive benefits over a smaller, less sophisticated market participant. According to Constellation, a wholesale supplier has the added expertise necessary to enter into more complex transactions which can provide additional appropriate management and hedging tools to further drive down costs.

Constellation believes that each of the tasks and positions described for Constellation's team plays an integral role in being able to drive down a wholesale supplier's costs of meeting load requirements and provide the most reliable, up-to-the minute improvements and adjustments to a portfolio of resources, from which all of the supplier's customers will benefit. Constellation asserts that without the benefits of accurate and around-the-clock weather monitoring and predicting, if an IPA Plan estimates a need and purchases block products ahead of time to meet a utility's expected eligible retail customer load for the summer, one can, for instance, evaluate a situation where there happens to be an unusually hot week in the middle of July. Constellation says the utility may face a situation where, because of the unusually hotter weather, homes and businesses are requiring much more electricity to run their air conditioners. Constellation states that if the IPA Plan did not accurately predict how much load it would have in that week, because of that inability to accurately predict and react to the weather, the utilities may face a situation where they need to purchase in the spot market the additional supply that it requires at high electricity rates because, as demand for electricity increases around the region during a hot week, supply becomes constrained and prices for limited supply increase. Constellation says the utility's consumers will bear the burden of the costs of this inability to accurately predict and plan for the weather in real-time.

Constellation claims that it and other wholesale suppliers continually monitor and predict the weather as part of their portfolio management function and are able to react in real-time and adjust supply accordingly and efficiently, with an incentive to keep costs low. According to Constellation the costs for all of the above types of expertise are mitigated significantly by utilizing a well-developed infrastructure and spreading the overhead for such activities across a supplier's entire portfolio of tens of thousands of megawatts of supply obligations across the country. Additionally, Constellation says the costs for full requirements product suppliers to provide such service for a utility's eligible retail customers will be highly constrained by the very competitive nature of this business, because wholesale suppliers throughout the market have operations similar in structure to those of Constellation, and will compete to serve a utility's eligible retail customers at the lowest cost.

According to Constellation, it is true that wholesale suppliers bidding on full requirements products may place a certain value on the risk that they assume, for instance, for customer migration. Constellation asserts 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. Constellation 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. Constellation suggests it is a zero sum game. Constellation says customers bear each "cost," either in the price or in the form of an assumed risk. Constellation believes this type of shifting of risks directly to consumers fundamentally alters the nature of the product being provided.

Constellation states that proponents of a managed portfolio approach often make claims that these monetizations and costs are exclusive to full requirements products. Constellation contends 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. Constellation argues 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. 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. According to Constellation, if the fixed costs for the added benefits of full requirements products, including for load variation, are highly constrained through the competitive nature of full requirements product procurements, then it would be difficult to imagine that a managed portfolio approach could result in more competitive prices than those achieved under the full requirements product procurements.

Constellation says 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. In reality, 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. Constellation contends that basic economic principles suggest that this is the case. Constellation says when a seller sells a product, whether he is selling oranges, widgets or electricity, he seeks a return on his costs of producing the product. Constellation claims basic economic principles also 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. According to Constellation, 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. Constellation says 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. Constellation claims 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. Constellation contends that 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.

In its Reply to Responses, Constellation argues that contrary to ComEd's claim, full requirements are not prohibited by statute. ComEd takes its position that full requirements are inconsistent with the PUA based in part on its reading that the legislature intended to replace the former auction process with that of an RFP process. Constellation contends that whether the competitive procurement is conducted via an auction or an RFP in and of itself does not preclude a full requirements solicitation. ComEd next cites to Section 16-111.5(b)((3)(iv) as evidence that the legislature intended to exclude full requirements. Constellation argues that a reading of that section of the law does not reveal such a prohibition. Constellation says the statute specifically provides for contracts executed for products "separately or in combination . . . including but not limited to." In Constellation's view, by the statute's own wording, the list of products was meant to be illustrative, not exhaustive. By combining various products identified in the statute, Constellation claims one can achieve a full requirements product. Constellation believes the IPA has the discretion to procure those products in combination.

Constellation asserts that ComEd's suggestion that full requirements should not be explored because the RFP process has worked well is not persuasive. Constellation argues that regardless of whether some feature of the IPA Plan has worked well in the past does not mean that the parties should be content with the status quo, and ignore different elements that carry the possibility of even greater success in the future. Constellation contends that the goal of the statutorily mandated IPA review process each year, and the requirement for filing a new plan each and every year, is so that the process can be continually improved upon. Constellation also says that narrow thinking does not address the varied and substantial potential benefits that full requirements can provide.

Although Constellation recognizes the fact that there may be some cost to suppliers wearing those risks that will factor into bids, Constellation claims those full supply costs are known and measurable at the time of the procurement results, in contrast to the current situation, in which the effects of inaccurate forecasting or significant customer migration cannot be known.

2. IPA's Position

The IPA opposes Constellation's proposal at this time. The IPA says that Section 1-5 of the IPA Act provides that the IPA 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 . . . ." As the IPA stated in previous submissions on this topic, Constellation's proposal that there is reduced price risk on eligible retail customers with full requirements contracts is unsupported, and the contrary may also be true – full requirements contracts shift the benefit of reducing prices to the wholesale supplier, and deprive eligible retail customers of the benefits of reduced prices in a declining market. The IPA believes that in reality, any risk associated with future demand for energy, whether declining or not, and future price for energy, is factored into the bids submitted by wholesale suppliers for block contracts. Finally, the IPA is not convinced that Constellation's suggestion to use full requirements contracts satisfies the PUA's statutory requirement for use standard wholesale products. While the IPA is willing to discuss the use of full requirements products in future procurement plans, it continues to believe that its current approach continues to be preferable to full requirements contracts.

3. ComEd's Position

ComEd disagrees with Constellation's recommendation that the IPA incorporate full requirements products within its Plan. ComEd understands that the Illinois General Assembly, in enacting Public Act 95-0481, intended to replace the Commission-approved auction process for acquiring full requirements products with an RFP process for standard wholesale products. According to ComEd, it is difficult to see how full requirements products are consistent with the definition of Standard Wholesale Product contained in the PUA. ComEd also argues that the RFP process has worked well. For those reasons, ComEd believes the Commission should continue to accept the IPA's proven plan for procuring block energy products and should decline to change the plan to use full requirements products.

4. AG's Position

The AG notes that Constellation objects to the 2012 Plan because it does not include "full-requirements" contracts. While it argues that full requirements contracts reduce customer risk, the AG asserts that it fails to establish: (1) that the risk of price fluctuation in the 2012 Plan approach is excessive or unreasonable, or (2) that the risk premium for full-requirements contracts justifies their use.

Constellation asserts that a full-requirements contract promotes opportunities for customers by providing well-defined, competitively-procured default service supply that provides appropriate benchmarks for comparisons to product offerings of ARES. The AG argues that suppliers are free to compete against full requirements contracts or the three-year laddered approach of the 2012 Plan. The AG suggest that while it may prefer to compete against a full requirements contract procurement, there is no reason that Constellation or other suppliers cannot compete against whatever services and prices are available to consumers from either the IPA or other suppliers.

The AG also asserts that Illinois experimented with full requirements contracts at the end of the statutory rate freeze in 2007 when full requirements contracts were the basis of the reverse auction approved by the Commission upon the petitions of ComEd and AIC. The AG claims the full requirements auction resulted in prices that exceeded market values by approximately 20%.

The AG asserts that the approach used by the IPA in this and prior procurements have more closely matched NYMEX Northern Illinois Hub prices. The AG urges the Commission to reject Constellation's objection to the 2012 Plan and reject its recommendation to return to unnecessarily expensive full requirements contracts in the 2012 Plan.

5. Solar Alliance's Position

The Solar Alliance believes requiring full-service supply contracts would limit competition in serving the load in Illinois. The Solar Alliance states that many component suppliers currently participating in the Illinois procurement process will not bid on full-requirements contracts. The Solar Alliance claims this has been proven out in New Jersey and other states with a history of full-service supply contracts. The Solar Alliance says even Constellation admits that full requirements contracts would be anti-competitive, noting in its Objections that it would have “significant competitive” advantages over “smaller, less sophisticated market participants.

According to the Solar Alliance, the IPA and many other electric buyers in many markets buy the components of full-service contracts because the full-service supply contracts offered by entities such as Constellation carry too much of a premium in exchange for the risks they say they would take on. According to Constellation, this suggestion would cost the ratepayers an additional $28.8 million in just energy year 2012 to 2013. Constellation’s “[a]nalysis suggests that a managed portfolio approach [like that currently used by the IPA, is] generally . . . cheaper than a full requirements structure.” The Solar Alliance believes that requiring a full requirements contract is simply not in the best interest of Illinois ratepayers; it would allow a few large companies to prosper at the ratepayer’s added expense.

6. IREC's Position

In its Reply to Responses, IREC argues that full requirements contracts are wholly inappropriate for renewable, intermittent generators, which are dependent on variable inputs to produce intermittent, as-available output. IREC notes that Constellation proposed in its Objections that full requirements contracting would shift the risks to wholesale providers, who would be required to meet and bear the risk of unexpected load. IREC believes this concept simply does not translate to intermittent generators who do not control the source fuel, i.e., the sun and the wind. IREC claims studies have shown that in the aggregate, solar generation provides predictability and reliability to the grid, despite the variability of any given individual project. IREC suggests aggregate output from 1,000 solar arrays across ComEd's and AIC's service territories would be very predictable a day in advance, though any one array will be subject to fluctuations caused by clouds. According to IREC, the proposal is inappropriate as a guiding principle for IPA's procurement planning and should be rejected.

7. ICEA's Position

In its Reply to Responses, ICEA notes that ComEd opposed a recommendation made by Constellation that the IPA incorporate full requirements products within its Plan. While ICEA itself has not made any recommendation as to the types of products that could and should be used by the IPA in its Plan, ICEA feels compelled to address ComEd's mischaracterization of full requirements contracts as not being "standard wholesale products."

ICEA says ComEd states that full requirements products are inconsistent with the definition of Standard Wholesale Product contained in the PUA. According to ICEA, the PUA does not even contain a definition of "standard wholesale product." ICEA says the PUA merely requires the IPA Plan to include a proposed mix and selection of standard wholesale products, and provides block products as an example of the types of products that could be included. ICEA states that the relevant section of the PUA, cited by ComEd, says the types of block products listed should be used "separately or in combination . . . including but not limited to" other standard wholesale products. ICEA asserts that by the statute's own wording, the list of products was meant to be illustrative, not exhaustive. ICEA claims by combining various products identified in the statute, one can achieve a full requirements product. ICEA believes the IPA has the discretion to procure those products in combination.

ICEA asserts that ComEd's claim that full requirements are inconsistent with the PUA, based in part on its reading that the legislature intended to replace the former auction process with that of an RFP process, also falls flat. ICEA claims that whether the competitive procurement is conducted via an auction or an RFP in and of itself does not preclude a full requirements solicitation.

According to ICEA, ComEd's suggestion that full requirements contracts should not be explored because the RFP process has worked well does not address the varied and substantial potential benefits that full requirements contracts can provide. ICEA claims regardless of whether some feature of the IPA Plan has worked well in the past does not mean that the parties should be content with the status quo and ignore different elements that carry the possibility of even greater success in the future. ICEA believes the goal of the statutorily mandated IPA review process each year, and the requirement for filing a new plan every year, is so that the process can be continually improved. ICEA rejects ComEd's notion that the IPA could not and should not consider using full requirements products in future procurement plans.

8. Commission Conclusion

Constellation recommends that the Plan should be modified to use full requirements, load following products. The IPA, ComEd, the AG, the Solar Alliance, and IREC oppose Constellation's proposal. ICEA disputes ComEd's assertion that full requirements are inconsistent with the PUA.

As in previous years, the IPA finds it is in the best interests of eligible retail customers to procure standard block products for energy. The Commission also notes that the General Assembly delegated to the IPA the primary responsibility for developing each procurement plan. While the Commission appreciates the input of Constellation, it has not demonstrated that its proposal is superior to the IPA's, from the perspective eligible retail customers. The Commission concurs with those parties, including the IPA, who contend that Constellation's assertion its proposal results in reduced price risk on eligible retail customers is unsupported. The Commission concludes that it is not necessary, at this time, to address ComEd's legal theory that full requirements products are inconsistent with the PUA.

S. Demand Response

1. Comverge's Position

Comverge notes that the Plan does not contain any provisions for using demand response to meet capacity needs of eligible retail customers. Comverge says the Plan does not even analyze demand response as an option or provide any mechanism for determining whether demand response is cost-effective for purchasing capacity for either ComEd or AIC. Comverge believes these omissions violate the requirements of Section 16-111.5(b) of the PUA.

Comverge believes that at a minimum, the IPA is required to determine whether cost-effective demand response measures can be procured at a lower cost than comparable capacity products. Comverge says Section 8-103(c) of the PUA requires both ComEd and AIC to use cost-effective demand response to reduce their peak demand from eligible retail customers by 0.1% per year over the prior year. Comverge indicates that according to the Plan, it is not clear if AIC is meeting this obligation.

Comverge asserts that the Plan unfairly locks eligible retail customers, residential and small business consumers, out of demand response programs. According to Comverge, large commercial and industrial customers and aggregators of such customers currently make demand response bids in PJM capacity auctions. Comverge claims that aggregators of residential and small business customers have not made bids at the PJM auctions, presumably because it is impractical. Comverge adds that large commercial and industrial customers have long been eligible for payments for demand response payments directly from ComEd and AIC pursuant to their tariffs. Comverge says that while ComEd has a program for residential demand response, new customers are not eligible for this program. In Comverge's view, under the Plan, residential and small business consumers are effectively denied any opportunity to receive demand response payments.

Comverge proposes that the IPA determine whether demand response products for capacity for, and from, eligible retail customers are cost-effective by using a procurement event. For ComEd, Comverge suggests the IPA should hold a separate, stand-alone procurement event in the spring of 2012 for capacity from demand response providers. Comverge says the RFP for such an event should specify that the IPA is seeking to purchase demand response capacity for and from eligible retail customers. Under Comverge's proposal, the IPA would include RFPs for five and ten year contracts. Comverge says the benchmark for determining whether bids are cost-effective from these procurement events would be the weighted average price of: (a) the average price of capacity projected by the procurement administrator for PJM's incremental capacity purchases, for the first three years of the contract, and (b) the average price of capacity projected by the procurement plan administrator for years four through ten, as applicable. Comverge believes the amount of capacity sought would range from 0.5% of projected capacity requirements in the first year to 2.5% of projected capacity requirements in year 10.

For AIC, Comverge proposes that the IPA allow demand response capacity bids in response to IPA's existing RFPs for capacity resources. Comverge says the short-time frame (currently monthly) for IPA's existing procurement events may not allow demand response providers to participate in such events in a cost-effective manner. Therefore, to supplement any of AIC's existing efforts to comply with its statutory obligations under Section 8-103(c) of the PUA to reduce peak demand by 0.1% per year over the prior year, Comverge contends the IPA should also hold a stand-alone procurement event in the spring of 2012 similar to the one proposed for ComEd demand response capacity procurement. Comverge suggests the RFP for such an event should specify that it is seeking to purchase demand response capacity for and from eligible retail customers. Again, under Comverge's proposal, IPA would include RFPs for five and ten year contracts. Comverge says the benchmark for determining whether bids are cost-effective from such procurement events would be the weighted average price of the projected capacity by the procurement plan administrator for all applicable years. Comverge again suggests the amount of capacity sought would range from 0.5% of projected capacity requirements in the first year to 2.5% of projected capacity requirements in year 10.

Comverge insists that its proposal is feasible. For ComEd, Comverge says the principal objection in the past to the IPA's procurement of demand response has been that ComEd's capacity for the next three years has already been purchased through PJM auctions. Comverge claims that this argument ignores that PJM's three-year forward-looking procurement covers only 97.5% of the projected need for capacity. Comverge says PJM supplements its base procurement with incremental capacity auctions. Comverge suggests the proposed IPA procurement event for the spring of 2012 could purchase some or all of the additional capacity that would otherwise be sold at PJM's incremental capacity auctions.

Comverge also says that PJM already has a process in place for returning capacity credits to ComEd if the amount of capacity procured exceeds the amount of capacity actually needed. To the extent that the IPA obtains bids for capacity for the next three years at its demand response procurement event, and ComEd has already purchased all of its capacity needs, then Comverge says ComEd can receive capacity credits from PJM and either bid those capacity credits into incremental PJM auctions or sell those credits to third parties.

Comverge asserts that because demand response contracts can be long-term, up to 10 years in length, savings in later years can make up for deficits in earlier years. Comverge says that to the extent that the cost of demand response products for a long-term contract is less than the weighted average of the benchmark during the entire period of the contract, then demand response capacity would be cost-effective and should be procured under the statute.

Comverge believes the fact that the proposed demand response contracts are longer term than current PJM purchase contracts is not a significant barrier. Comverge says the utilities and IPA currently have statutory obligations to include cost-effective renewable energy resources. To fulfill those obligations, Comverge says IPA has previously entered into 20 year contracts, and proposes to invite bids for 10 and 20 year contracts in procurement events in 2012.

According to Comverge, the IPA can and must create its own process for using demand response and assessing whether it is cost-effective. Comverge believes that criticism of its proposal does not prove that demand response is not cost-effective or relieve the IPA of its statutory obligation. Comverge insists that the IPA is obligated by statute to create some method to determine whether demand response proposals are cost-effective, and Comverge believes the market is the best way to test whether demand response bids can meet this standard.

In its Reply to Responses, Comverge complains that the IPA does not include the mix of demand response products for which contracts will be executed during the next year in its Proposed Plan. Comverge says the IPA states in its Response that the IPA is committed to working with interested parties to develop a demand response proposal that is consistent with the statutory goals and will conduct workshops to discuss proposals for accomplishing these goals.

Comverge appreciates the opportunity to participate in such workshops. Although Comverge acknowledges that these workshops could be productive with respect to inclusion of demand response in future IPA procurement Plans, Comverge does not see how the workshops could lead to the inclusion of procurement of demand response in the IPA's 2012 Procurement Plan. Comverge urges the Commission to make the revisions to the Proposed Plan set out in Exhibit A to Comverge's Objections so that the IPA's Procurement Plan 2012 does not violate Illinois law.

According to Comverge, ComEd tacitly acknowledges that demand response is completely ignored in the Proposed Plan, in contravention of the statute, by discussing past IPA procurement plans rather than the current Proposed Plan. Comverge disputes the arguments ComEd makes regarding the Commission's prior decisions that the IPA was not required to include demand response in its procurement plans. Comverge says the prior IPA procurement plans simply proposed the use of stand-alone auctions for demand response, with no explanation or detail of how those auctions would function. In contrast, Comverge claims it has proposed a mechanism for how demand response procurement would function, and how the IPA would determine that bids would meet the cost-effectiveness test of the statute.

Comverge states that in prior proceedings regarding IPA procurement plans, the Commission relied on its understanding that PJM purchased all of the necessary capacity three years in advance. As a result, the Commission concluded any additional purchase of demand response capacity would be additive. Comverge maintains that PJM actually purchases only 97.5% of its expected capacity three years in advance. ComEd does not dispute this fact. Comverge proposes that demand response capacity purchases be limited to 0.5% of projected capacity requirements in initial years. Comverge proposes that the demand response capacity would be purchased through five and ten year contracts – well outside the time frame covered by the PJM auctions. Comverge insists these demand response purchases would not lead to "additive" purchases of capacity that would increase customers' bills as ComEd contends.

Comverge believes the demand response RFP process it proposed is a mechanism to determine whether cost-effective demand response capacity products are available or not. Assuming that the Procurement Administrator uses a proper benchmark (either the one proposed by Comverge or another benchmark that the procurement administrator develops), Comverge asserts the RFP process would either lead to the purchase of cost-effective demand response capacity products, or the purchase of no demand response products.

According to Comverge, ComEd's claim that a vibrant and robust demand response market exists for residential and small business customers is not accurate. To support its claim, ComEd points to its Direct Load Control Program ("DLC") for residential customers. Comverge claims that ComEd stated in its 2011-2013 Energy Efficiency and Demand Response Plan dated October 1, 2010, that "ComEd will maintain the [DLC] A/C Cycling program at its current level in maintenance mode over the next three years but will not grow the program."

Comverge notes that ComEd also references its Voluntary Load Reduction Program. Comverge contends that this program includes only a few hundred small business customers - a tiny fraction of the market. Finally, ComEd notes that curtailment service providers ("CSP") participate in PJM's auction. Comverge complains that ComEd does not provide any evidence that these CSP aggregate residential or small business customers, much less that they aggregate Illinois residential and small business customers. Comverge asserts that aggregators for Illinois residential and small business customers do not participate in the PJM market because the terms that PJM requires for bids are not practical for demand response aggregators of these customers. Comverge contends that demand response for residential and small commercial customers is uneconomic in the PJM market because of the limited time horizon of the PJM capacity markets.

While Comverge believes its proposal is a useful tool to show that some mechanism is feasible, criticisms of the details surrounding Comverge's proposal do not mean that the IPA's Proposed Plan meets statutory requirements.

Comverge claims that ComEd argument that, under Comverge's proposal, ComEd would be required to purchase capacity at PJM base auction prices (currently $110/MW-day for 2011-12 and resell them at PJM incremental auction prices (currently $5/MW-day) mischaracterizes Comverge's proposal. Comverge say under its proposal, the proposed benchmark for the first three years would be PJM's incremental auction price, not the base auction price.

It appears to Comverge that ComEd implies that it cannot procure capacity outside of the PJM process. Comverge claims ComEd already purchases demand response capacity from customers through its Rider CLR7, Direct Load Control Program and Voluntary Load Reduction Program. Comverge says ComEd bids demand response capacity into PJM auctions. According to Comverge, there is no reason why ComEd can bid its current demand response capacity into PJM auctions, but would not be able to bid demand response capacity purchased at IPA auctions into PJM.

Comverge states that ComEd complains against using long-term contracts. Comverge responds that PJM already requires ComEd to purchase 97.5% of its capacity three years in advance. Comverge presumes that ComEd and PJM approve of this speculative purchasing because they believe it is prudent to hedge against the risk of higher prices existing at the time the capacity is actually needed. Comverge also asserts that it is prudent to hedge against the risk of increased future capacity costs by purchasing cost-effective demand response capacity with longer-term contracts. Comverge says ComEd's own consultant projected that future capacity costs will more than triple by 2015 (from $110/MW-day to $379.43/MW-day) and will continue to rise to $484.26/MW-day by 2020.

Comverge says AIC responded that demand response providers can already participate in IPA solicitations for capacity if such resources are registered as PRC at MISO. Comverge asserts that demand response aggregators cannot, as a practical matter, participate because IPA is proposing such a short time frame for AIC for its capacity procurement events. Comverge says even one year capacity auctions are not practical for residential and small commercial demand response products. Comverge insists that the RFP procurement processes it proposed, which would entail five- and ten-year contracts, should be adopted in the IPA's 2012 procurement Plan.

Staff argues in its Response to Objections that the Procurement Administrator is responsible for developing benchmarks, and Comverge says it agrees. Comverge claims its Objections contain proposals for implementation of a demand response procurement process for IPA and a suggestion for calculation of a proposed benchmark. Comverge says it is confident that its proposal will help efforts to implement a mechanism to determine whether demand response capacity is cost effective, consistent with the statutory mandate. Comverge agrees the Procurement Administrator is ultimately charged with developing and implementing the actual benchmark used to comply with the statute.

2. AIC's Position

AIC notes that Comverge states that "at a minimum the IPA is required to determine whether cost-effective demand response measures can be procured at a lower cost than comparable capacity products. Nevertheless, the proposed Plan totally ignores demand response products despite the clear statutory requirement." AIC disagrees with this statement on the basis that any IPA solicitation for capacity allows demand response resources if such resources are registered as PRCs at MISO. AIC says after each IPA solicitation for PRCs, AIC is provided is list of winning suppliers and the associated terms and quantities that each supplier has been awarded. AIC claims it has no way of determining whether such PRCs are from traditional capacity resources or demand response resources. Nevertheless, AIC states that demand response resources are allowed to participate in the IPA solicitations so long as they are registered at MISO. AIC says this includes demand response resources from eligible retail customers. AIC claims such demand response resources can compete head to head with traditional capacity resources solely based on price and therefore the test for cost effectiveness desired by Comverge is already met through the IPA solicitation process. AIC says this issue of who should be responsible for registering demand response at MISO has been debated extensively in previous Plans (Docket No. 10-0563 and Docket No. 09-0373), so it will not belabor the Commission by repeating a detail of its position here. AIC maintains the proper place for demand response resources to compete with traditional capacity is at the level of MISO, with registration being the responsibility of each demand response provider.

3. ComEd's Position

In ComEd's view, Comverge both misinterprets the plain language of the PUA and ignores the long history of Commission decisions interpreting and applying the law to demand response proposals. ComEd indicates that Section 16-111.5(b)(3)(ii) of the PUA provides that the Plan shall include "the proposed mix of demand-response products for which contracts will be executed during the next year." That subsection goes on to provide that "cost-effective demand response measures shall be procured whenever the cost is lower than procuring comparable capacity products . . . ."

According to ComEd, if cost-effective demand response measures cannot be procured at a cost lower than comparable capacity products then, no contracts will be executed and there will be nothing to include in the Plan regarding demand response. ComEd suggests a review of the history of this issue at the Commission demonstrates, cost-effective demand response measures cannot be procured through a separate procurement process in ComEd's territory due to the operation of PJM's RPM.

ComEd says the Commission first addressed this issue in Docket No. 09-0373. There, ComEd indicates the IPA had proposed to procure demand response measures independently, supposedly pursuant to PUA Section 16 111.5(b)(3)(ii). ComEd reports that the Commission rejected this proposal because procuring additional demand response resources outside the PJM process was not cost-effective.

According to ComEd, the IPA repeated its proposal in the procurement plan for the next year, apparently believing it was required to do so by the PUA. ComEd says the Commission again rejected the proposal, pointing out the fallacy in the argument for additional demand response procurements.

It is ComEd's position that nothing relevant to the operation of PJM's RPM, or the capacity requirements applicable to ComEd thereunder, has changed since the Commission entered those decisions. ComEd asserts that cost-effective demand response resources cannot be procured in the ComEd territory outside of the RPM process. ComEd believes that any additional demand response measures that ComEd obtains and bids into PJM will not reduce its PJM capacity obligations and will result in additional costs being borne by its customers, no matter what the price at which that demand response is acquired. ComEd claims that is because PJM determines capacity obligations on the basis of a peak load forecast that includes all load that is shed by implementing such demand response measures. ComEd says PJM does this because it must procure resources to serve all anticipated load, including load associated with demand response.

ComEd disputes Comverge's assertion that residential and small commercial customers are effectively denied any opportunity to receive demand response payments. ComEd says it offers two demand response programs that are available to residential and small business customers. ComEd claims the Direct Load Control Program has over 70,000 residential customer participants. ComEd says that contrary to Comverge's claim, it is currently available to all residential customers. ComEd also says it has bid 25 MW of capacity from this program into the PJM RPM capacity auctions.

ComEd also indicates that it offers the Voluntary Load Reduction Program to any nonresidential customer that can commit to a 10 kW load reduction. ComEd states that currently, several hundred small (i.e., <100kW) business customers participate. ComEd says it bids the capacity from this program into the PJM RPM.

ComEd asserts retail customers can also access PJM's demand response programs and RPM market through independent CSPs. According to ComEd, this is not just a theoretical option. ComEd says PJM lists 47 active CSPs in the ComEd zone. ComEd claims these CSPs account for over 1,200 MW of demand response registered as capacity in the ComEd zone.

In ComEd's view, there can be no dispute that the demand response market for residential and small business customers is functioning well and that all available economic resources can participate in the PJM market.

Comverge first argues that because PJM only procures 97.5% of its projected need for capacity in the base auction, ComEd can procure more demand response this spring through the IPA rather than suppliers having to bid into one of PJM's incremental auctions. ComEd suggests it should not do this. ComEd does not believe that the CSPs would not capture all of the practical and economic demand response that is available. ComEd claims suppliers will not resell resources to ComEd at or below RPM market prices, they can already sell all the demand response they have available to PJM. According to ComEd, Comverge supplies no credible reason why having ComEd act as an intermediary that must buy and resell resources into the same PJM market that the CSPs already operate in will reduce costs to customers. ComEd contends that that by acting as such an intermediary, ComEd will effectively be turned into a speculator that purchases the IPA capacity at one price with the hopes of selling it into a PJM incremental auction at a later date and passing all of the associated losses or gains on to its customers. ComEd asserts this would have been a bad bet in the past. ComEd claims that the 2011/12 planning year base auction cleared at a price of $110.00/MW-day, while the excess resources disposed of in the final incremental auction returned only $5.00/MW-day. While not always as stark, ComEd contends the same risk will always apply. According to ComEd, for the last four years, buying at the base residual auction price and selling into the PJM Incremental auctions would have lost money for customers. As a matter of principle, ComEd believes it should only procure resources required by its customers, not speculate in the capacity markets. ComEd argues that it should not speculate in a manner suggested by Comverge that historically would have lost money.

ComEd states that the RPM is comprised of one base residual auction and up to three incremental auctions per delivery year (June 1 – May 31). ComEd claims is obliged to fully cover its capacity obligation through the RPM process, which includes both base and incremental auctions. ComEd says the 97.5% obligation applies only to the initial base auction, which is held during the month of May, three years prior to the actual delivery year. Even assuming that it were feasible and reasonable for ComEd to procure more demand response directly, which ComEd asserts it is not, ComEd claims it would not be cost-effective. ComEd insists any such demand response would not lessen ComEd's capacity obligation in the RPM process, or PJM's capacity charges to ComEd.

ComEd argues that the only parties who would potentially benefit from this arrangement are the companies who sell ComEd the demand response. ComEd claims the money flow in such a situation would be as follows: PJM pays ComEd the Incremental Auction clearing price, ComEd must pay the CSP the IPA determined price, and the CSP pays the selling retail customer. ComEd presumes that the CSP can lock in a profit by selling to the IPA only if the price exceeds what it pays to the selling customers. ComEd says its customers however see no reduction in PJM capacity charges. Instead, ComEd indicates they have to pay PJM’s full capacity charges plus all of the costs involved in setting up and administering this demand response program plus any difference between the price paid for the demand response in the IPA procurement and what, if anything, ComEd receives in the PJM incremental auction.

ComEd also disputes Comverge's argument that PJM will provide capacity credits to ComEd if ComEd procures excess capacity and that ComEd can then turn around and sell those capacity credits, claiming this is not how the PJM process works. ComEd says only when PJM, not ComEd, winds up with more capacity than it needs for reliability can PJM allocate the excess to all load serving entities (“LSE”) in PJM in the form of Excess Commitment Credits (“ECCs”). ComEd asserts that because PJM is really the only ultimate purchaser of RPM capacity in the market, when PJM declares it has more capacity than it needs, there are few if any buyers and the price is, unsurprisingly, minimal. ComEd claims PJM initially will attempt to sell into its incremental auctions any excess capacity it has acquired in its prior auctions. ComEd says only if PJM is unable to sell such excess capacity does PJM then allocate ECCs to the LSEs. According to ComEd, if PJM is unable to sell this capacity, there is no reason to believe an LSE will be able to. ComEd also says the ECCs are valid only in the planning year for which they were issued, i.e. the planning year in which PJM has already acquired more capacity than it can use. ComEd indicates that ECCs cannot be carried over to other years to offset RPM capacity obligations.

ComEd also argues that there is no guarantee that ComEd will actually receive any ECCs for any demand response that it would procure through the IPA process. That is because, ComEd claims, PJM allocates ECCs to LSEs only when the PJM system as a whole ends up with excess capacity and it makes this determination by reviewing the capacity obtained in the RPM auctions. ComEd posits a scenario where ComEd contracted for 100 MW of capacity through a process like Comverge recommends. ComEd says if PJM eventually determines that the PJM system did not end up with any excess capacity for the plan year, it would not issue any ECC’s. ComEd contends the 100 MW of IPA demand response capacity that ComEd procured would not result in ComEd receiving any ECCs. ComEd says its customers would pay significant sums of money for nothing.

ComEd contends that if, contrary to Comverge’s vision, those demand response resources had been bid into the initial PJM Base Residual Auction as intended, the capacity price would have been reduced for all PJM capacity purchasers including ComEd and its customers. ComEd asserts this is precisely why the Commission has found the proposal to purchase demand response outside of the PJM process unsupportable in the past and why it should do so again in this plan.

Comverge argues that procuring demand response pursuant to long-term contracts can be cost-effective because savings in later years can make up for deficits in earlier years. ComEd complains that Comverge never explains where these “later year savings” would come from or why providers would give the savings to ComEd customers rather than sell into PJM’s capacity market at a presumably higher future price. In ComEd's view, while the proposal is vague, it appears that Comverge is again suggesting that ComEd speculate on behalf of its customers by purchasing demand response under a long-term contract in the hope of selling it into future PJM auctions at a profit since the long-term demand response purchased outside of PJM will not reduce ComEd’s capacity obligation. ComEd maintains such speculation is not in the best interest of ComEd’s customers.

While Comverge notes that the IPA has procured 20 year contracts in the past, ComEd says it fails to note that such contracts were designed to meet future REC and energy requirements. ComEd insists that demand response purchased outside of RPM for later sale into an RPM auction would not meet or lower ComEd’s capacity obligation as such demand response is always added back into the load forecast.

ComEd suggests that the Commission and the IPA should consider revising the Plan to eliminate this issue. If the Commission wishes for the Plan to address that issue explicitly, ComEd believes the Commission should direct that the following language be added to the Plan:

> Section 16-111.5(b)(3)(ii) provides that the Plan should include the proposed mix of cost-effective demand-response products for which contracts will be executed during the next year. Any demand response measures that ComEd procures will not serve to lessen ComEd’s capacity obligation or the capacity charges it must pay to PJM. The cost of all such demand response will be an additional charge that must be borne by ComEd’s retail customers. Thus, such demand response is not cost-effective and ComEd will not be entering into any such contracts during the period of this Plan.

4. IPA's Position

The IPA notes that it included demand response in its previous two Procurement Plan submissions. The Commission rejected its inclusion for various reasons, but did not foreclose its consideration entirely. The Commission and the IPA welcomed further comments and arguments for inclusion in future Plans.

While the current Plan does not include demand response, the IPA maintains that the IPA Act directs that the IPA promote and advance demand response measures. Section 1-5 declares that demand response measures are currently under used in

Illinois, and directs that "it is necessary . . . to promote investment in . . . demand-response measures" in Illinois. This section also requires the Agency to annually report "to the Governor and the General Assembly on the . . . transactions of the Agency." The IPA says this report is required to specifically identify the "quantity, price, and rate impact of all energy efficiency and demand response measures purchased for electric utilities." Section 16-111.5(b) requires that the IPA develop a procurement plan that includes a "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 is committed to working with interested parties to develop a demand response proposal that is consistent with these statutory goals. As such, the IPA will conduct workshops to discuss proposals for accomplishing these goals.

5. Commission Conclusion

Comverge argues that because the Plan does not contain any provisions for using demand response to meet capacity needs of eligible retail customers it is violates Section 16-111.5(b) of the PUA. Comverge proposes that demand response capacity purchases be limited to 0.5% of projected capacity requirements in initial years. Comverge also proposes that the demand response capacity would be purchased through five and ten year contracts.

AIC, ComEd, and the IPA dispute Comverge's position and oppose its recommendations. The Commission has addressed the issue of demand response in each previous procurement proceeding. In Docket No. 09-0373 the Commission stated:

> 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)

It is Comverge rather than the IPA urging the Commission to pursue demand response this year. The Commission believes, however, that Comverge has provided no basis for the Commission to conclude that pursuing additional demand response would be beneficial to eligible retail customers. For purposes of the 2012, the Commission concludes that the record does not support the recommendation of Comverge and it is hereby rejected.

T. Technical and Miscellaneous Corrections

ComEd says the Commission is specifically authorized by Section 16-111.5(d)(3) of the PUA to enter an "order confirming or modifying the procurement plan" and the IPA Act provides that the IPA "shall revise a procurement plan if the Commission determines that it does not meet the standards set forth in Section 16-111.5 of the Public Utilities Act." According to ComEd, while the obvious intent of these provisions is to arrive at a final Commission-approved Procurement Plan, a final Commission approved version of the Procurement Plan has not in the past been readily available. Instead, parties had to individually review the Plan initially filed plus the Commission's Final Order revising it.

ComEd believes that it would be helpful to all parties if a Procurement Plan, as approved, was prepared and made generally available. ComEd also believes that having a final and approved version of the plan would be more convenient to all parties, including future potential bidders, provide greater clarity, and reduce potential confusion or misinterpretation of the final-approved Plan's provisions. Thus, ComEd recommends that the Commission's Final Order in this proceeding provide that the IPA submit an "as approved" version of the Procurement Plan as a compliance filing in this Docket. ComEd recommends this filing occur within 14 days of the Final Order, but has no objection to a longer period if that would be more convenient to the IPA.

In its Response to Objections, AIC agrees with the proposal as put forth by ComEd and reiterates the difficulty associated with comparing the filed Plan to the Commission's Order. AIC believes having a final and approved version would alleviate this concern.

In its Response to Objections, the IPA commits to posting to its website a final Plan taking into account the Commission's Order within 30 days of Plan approval.

In its Reply to Responses, Staff indicates that agrees that a final and Commission-approved Plan would be helpful to all stakeholders and appreciates the IPA's willingness to provide it within 30 days of approval. However, Staff believes it would be useful for Staff to review the final Plan to ensure it complies with the Final Order of the Commission. Staff recommends the IPA circulate its final Plan to Staff within 30 days for its comments, then file the Plan on e-Docket under Docket No. 11-0660 within 60 days, as well as on the IPA website.

In its Reply to Responses, AIC indicates that the IPA commits to posting to its website a final Plan taking into account the Commission's order within 30 days of Plan approval. AIC says while it appreciates the efforts of the IPA in this regard, it is noteworthy that ComEd recommended the IPA submit an "as approved" version of the Plan as a compliance filing in this Docket. AIC agrees with this recommendation by ComEd. AIC says this would become especially important given a scenario where the final Plan has errors or inconsistencies with the Commission's Order. Under the IPA proposal, AIC believes it is unclear what recourse the parties would have, if any, to correct such errors or inconsistencies. AIC therefore recommends the IPA submit its final Plan as part of a compliance filing in the docket.

It appears to the Commission that ComEd, AIC, Staff, and the IPA are generally in agreement on this issue, although there is some disagreement about how it should be implemented. Having reviewed the various proposals of the parties, the Commission finds that Staff's proposal is the most reasonable and appears to largely mitigate the concerns of other parties. For purposes of the 2012 Plan, the IPA is directed to implement the recommendation of Staff. As stated earlier in this Order, when the IPA provides its draft to Staff and when it files the updated Plan, the Commission directs the IPA to update the energy charts and capacity values for both AIC and ComEd to reflect the updated load forecasts filed in this proceeding.

ComEd also provided a redlined version of the Plan as Attachment B to its Objections, which identified technical errors that it identified in the Plan. With the IPA commitment to provide a final post-Commission Order Plan, in order to help facilitate corrections, the IPA requests that ComEd provide a list of specific additional typographical and arithmetic errors to be included in that final Plan.

AIC notes that on page 49 of the Plan, Table U should reference the “2012 Cycle” rather than the “2011 Cycle." The IPA agrees with AIC’s correction and suggests that it be incorporated into the final Plan.

The Commission believes that there is no need to address the technical corrections. It appears that the IPA intends to incorporate the necessary changes into a revised Plan that will be filed in this proceeding consistent with the Commission's conclusion immediately above.

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 28, 2011, as modified to incorporate the update in AIC's November 15, 2011 "Motion

for Leave to File Updated Load Forecasts" should be approved; the load forecast for ComEd attached to the IPA's September 28, 2011 petition, as modified to incorporate the update in ComEd's November 17, 2011 "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 28, 2011 Plan, as modified by the Commission conclusion in Section VII. K of this Order, 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 implementation of the approved Plan, the IPA is directed to implement the technical corrections adopted in Section VII.T of this Order.

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, 2011.

(SIGNED) DOUGLAS P. SCOTT

Chairman